NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Balancing and Frequency Control

Reference Document

Prepared by the NERC Resources Subcommittee

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RELIABILITY | RESILIENCE | SECURITY




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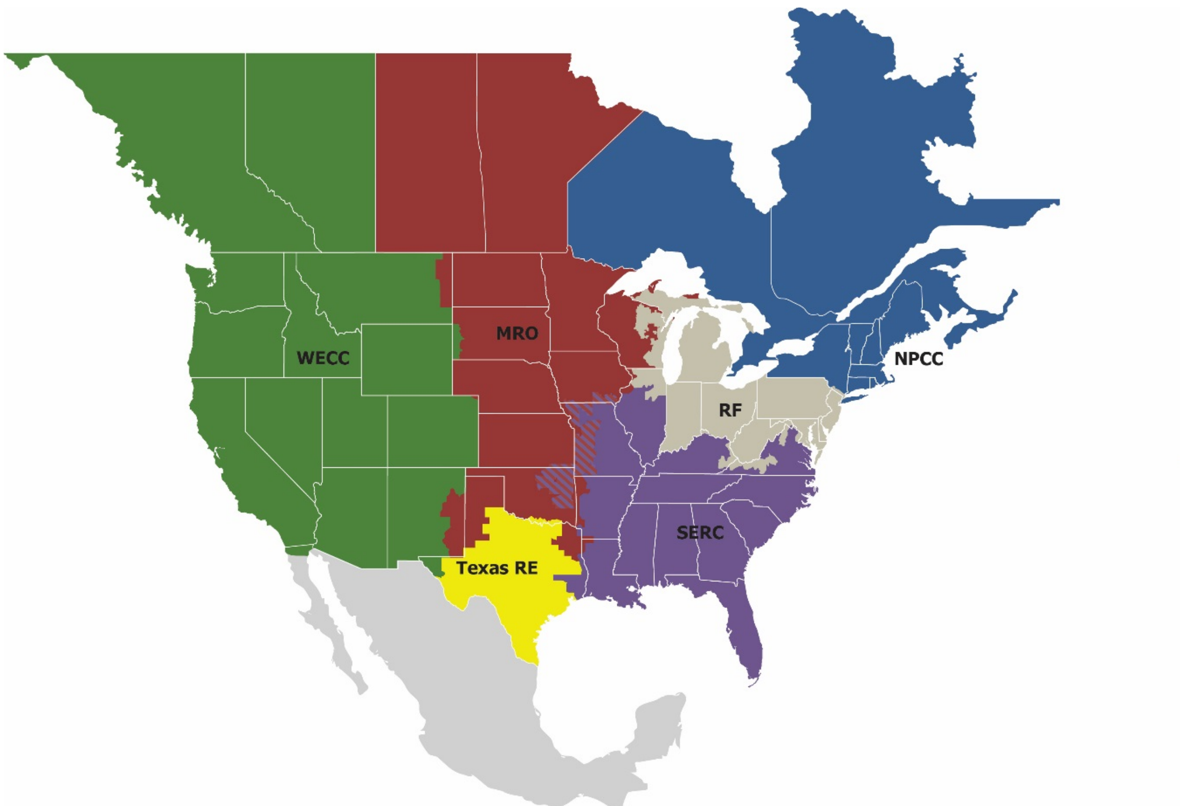
Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the six Regional Entities (REs), is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security

Because nearly 400 million citizens in North America are counting on us

The North American BPS is divided into six RE boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Region while associated Transmission Owners/Operators participate in another.



The Six Regional Entities	
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Introduction

Background
The NERC Resources Subcommittee (RS) drafted this reference document at the request of the NERC Operating Committee as part of a series on operating and planning reliability concepts. The document covers balancing and frequency control concepts, issues, and recommendations. Send questions and suggestions for changes and additions to balancing@nerc.com.

Note to Trainers
Trainers are encouraged to develop and share materials based on this reference. The RS will post supporting information on the RS website.[1]

Disclaimer
This document is intended to explain the concepts and issues of balancing and frequency control. The goal is to provide an understanding of the fundamentals. Nothing in this document is intended to be used for compliance purposes or to establish obligations.

[1] https://www.nerc.com/comm/OC/Pages/Resources-Subcommittee.aspx

Chapter 1: Balancing Fundamentals

Balancing and Frequency Control Basics

The power system of North America is divided into four major Interconnections (see **Figure 1.1**). These Interconnections can be thought of as independent electrical islands. The four Interconnections consist of the following:

- **Western Interconnection (WI):** Generally everything west of the Rockies
- **Texas Interconnection (TI):** Operated by the Electric Reliability Council of Texas (ERCOT)
- **Eastern Interconnection (EI):** Generally everything east of the Rockies except Texas and Quebec
- **Quebec Interconnection (QI):** Operated by Hydro Quebec TransEnergie

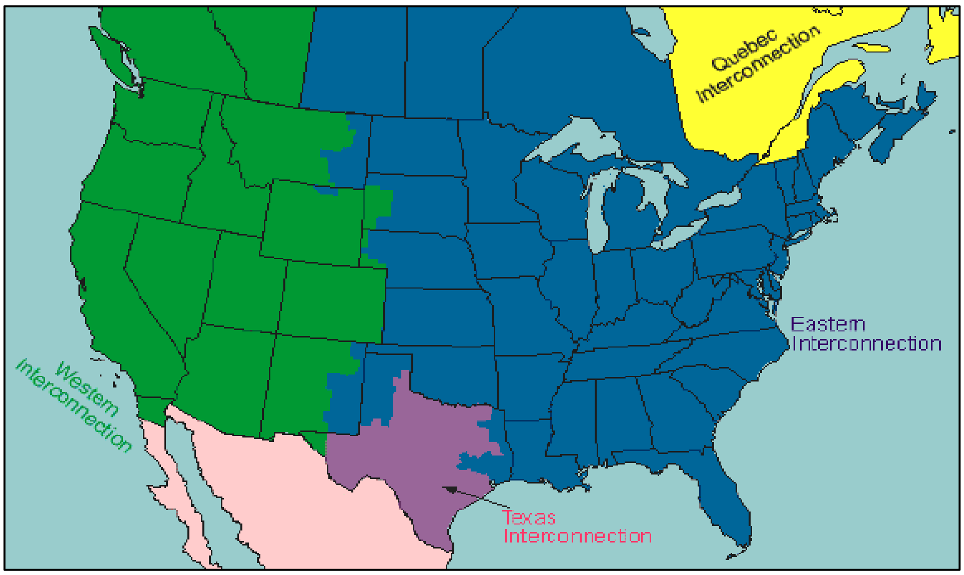


Figure 1.1: North American Interconnections

Each Interconnection can be viewed as a single large machine with every generator pulling together to supply electricity to all customers. This occurs as the electric generating units rotate (in steady-state) synchronously. The “speed” (rotational speed) of the Interconnection is frequency measured in cycles per second, or Hertz (Hz). When the total Interconnection supply exceeds customer demand, frequency increases beyond the scheduled value (typically 60 Hz[2]) until energy balance is achieved. Conversely, when there is a temporary supply deficiency, frequency declines until a balance between supply and demand is restored.

During normal operations it is typical for there to be small mismatches between total demand and total supply, so the frequency of each Interconnection varies above and below nominal on a continuous basis. Regardless of whether the variations are above or below scheduled frequency, the supply-demand balance is restored due to frequency sensitive demands and supply resources that change output in response to frequency changes. For example, some electric devices (e.g., electric motors) use more energy if driven at a higher frequency and less at a lower frequency. Most generating units are also equipped with governors that cause the generator to inject more energy into the Interconnection when frequency is lower than nominal and slightly less energy when the frequency is higher than nominal.

[2] Nominal frequency (termed “scheduled frequency”) is sometimes intentionally offset by a small amount via a mechanism called time error corrections to correct for sustained periods of high or low frequency.

Balancing Authorities (BAs) balance generation and load within their Balancing Authority Areas (BAAs) of the Interconnections. See **Figure 1.2** for an example of BAAs across North America. The BAs dispatch generating resources in order to meet their BAA demand and manage the supply/demand balance. Some BAs also control demand to maintain the supply/demand balance.

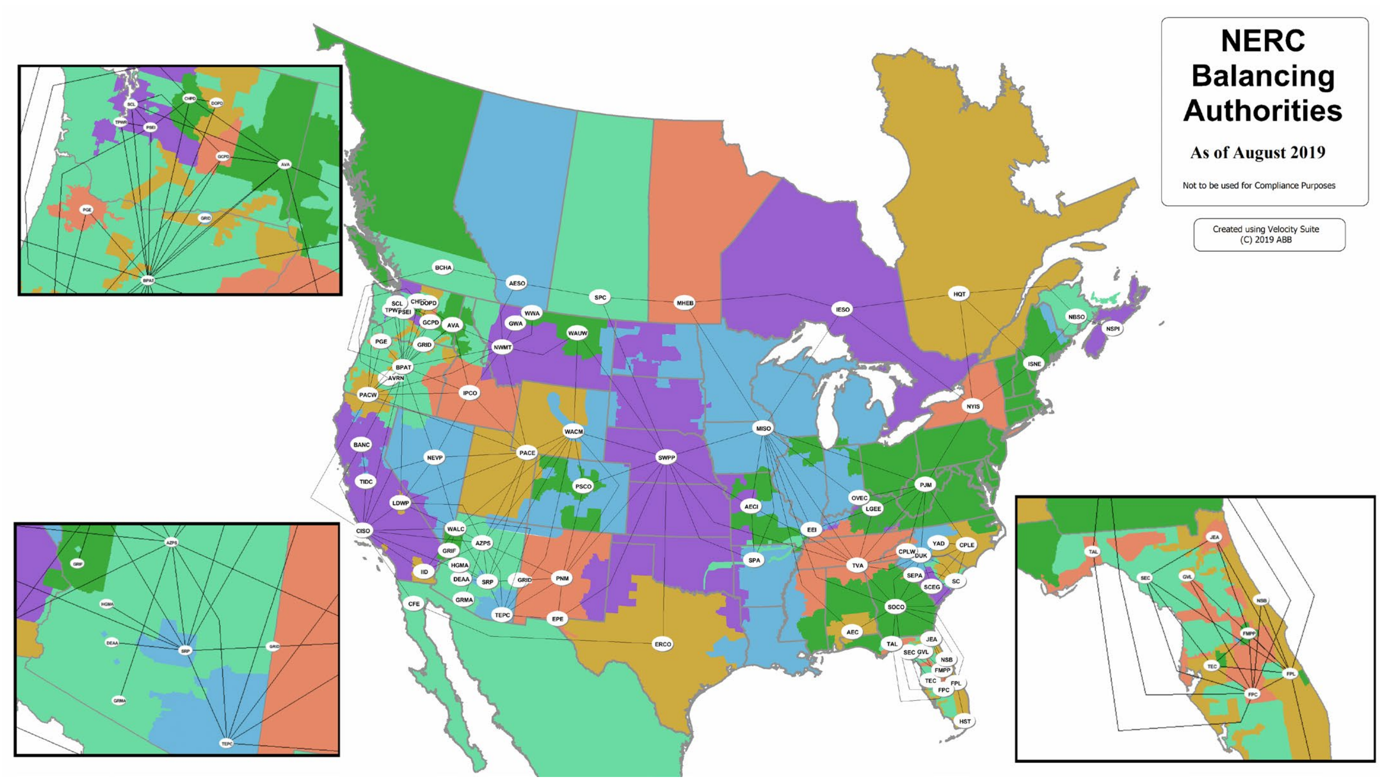


Figure 1.2: North American Balancing Authorities and Regions

The number of BAs in an Interconnection varies; Texas and Quebec are single BA Interconnections while the Eastern and the Western are multi-BA Interconnections. Each BA in an Interconnection is connected via high voltage transmission lines (called tie-lines) to neighboring BAs. The Reliability Coordinators (RCs) oversee the BA operations and coordination. BAs are responsible for the supply/demand balance within their BAA while RCs are responsible for the wide area health of the Interconnection.

Frequency will be constant in an Interconnection when there is a balance between supply and demand, including various electrical losses. This balance is depicted in **Figure 1.3**.

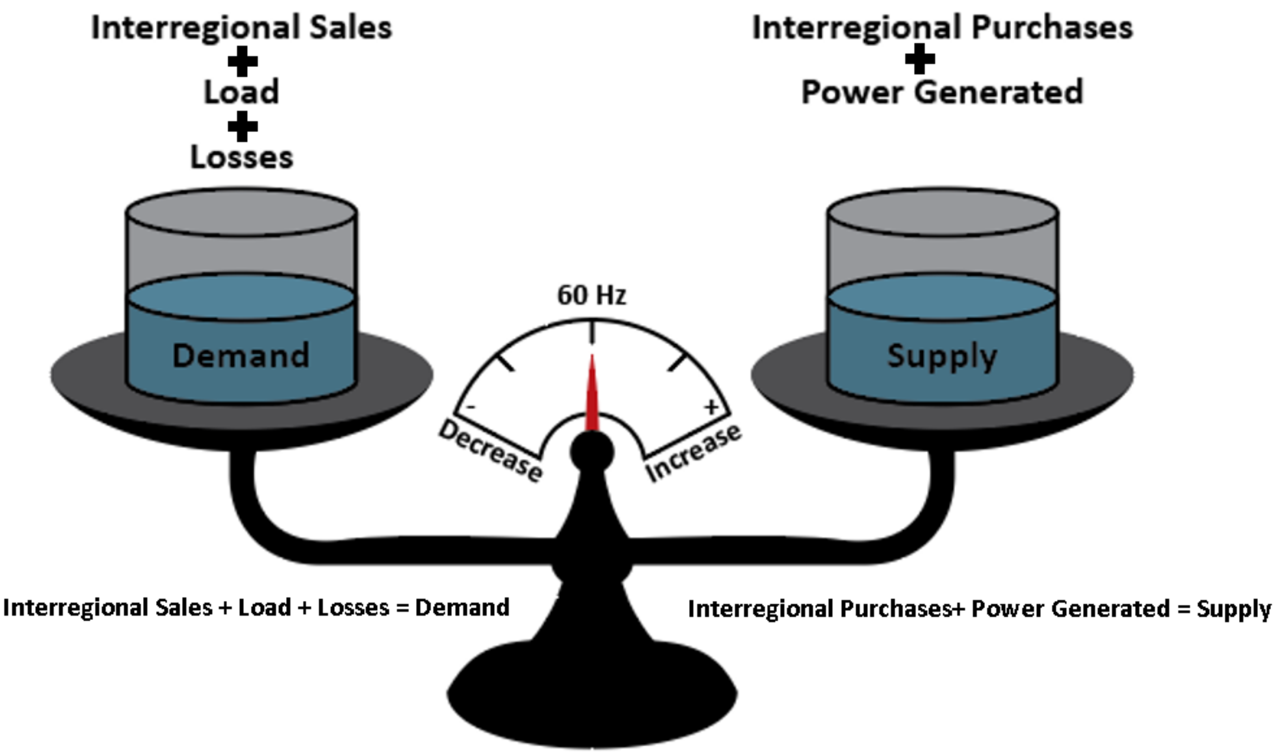


Figure 1.3: Generation | Demand Balance

Each supply resource embedded in an interconnected system has its own characteristics (e.g., ramp rates, fuel supply, output controllability, and sustainability). From a simplified viewpoint, a supply resource can be analogized to a water pump with storage and control as shown in **Figure 1.4**. In this example, the pump's output fills an open storage tank similar to a swimming pool. The water depth in the tank needs to be controlled to within very tight limits: too much water accumulating will cause the pool to overflow, and too little water will cause other problems. The control valve changes average output to meet system demand in a manner analogous to automatic generation control (AGC). The surge tank on the final output is analogous to the rotational inertia of the generator.

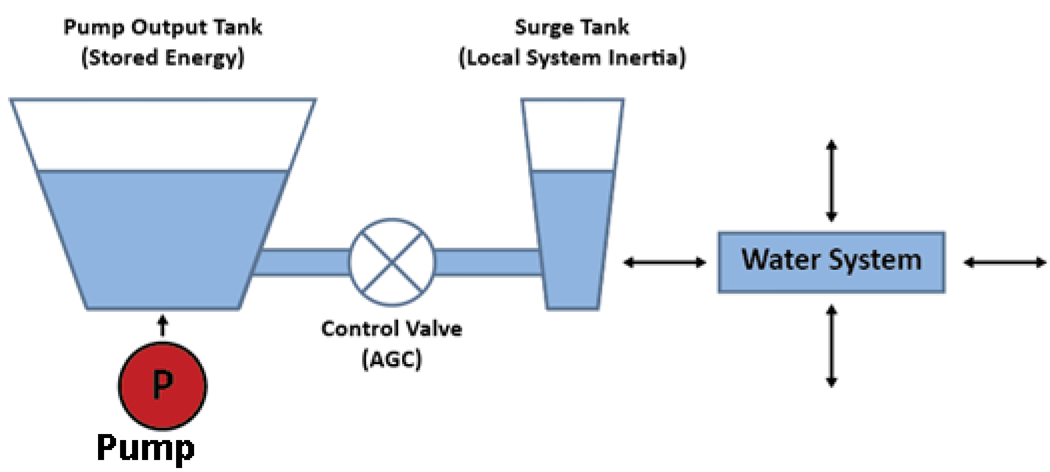


Figure 1.4: Generator | Pump Analogy

To understand how Interconnection frequency is controlled, it may help to visualize a traditional water utility that is composed of a delivery system, customers, and several pumping stations as depicted in **Figure 1.5**. If a municipality operates its own system, it needs sufficient pumps (supply) to maintain the water level in the pumping stations' storage tanks (frequency) to serve its customers. When demand exceeds supply, the water levels in the pumping station tanks will drop prompting the pumps to respond. Water level (frequency) is the primary parameter that must be controlled in an independent system.

In the early history of the power system, utilities quickly learned the benefits in reliability and realized reduced expense associated with maintaining operating reserves by connecting to neighboring systems. In our water utility example, an independent utility must have pumping stations in standby that are equivalent to its largest on-line pump if it wants to maintain the water level in case there is a problem with the largest pumping station. However, if utilities are connected together via tie-lines, reliability and economics are improved because of the larger resource capacity of the combined system and the ability to share capacity when needed.

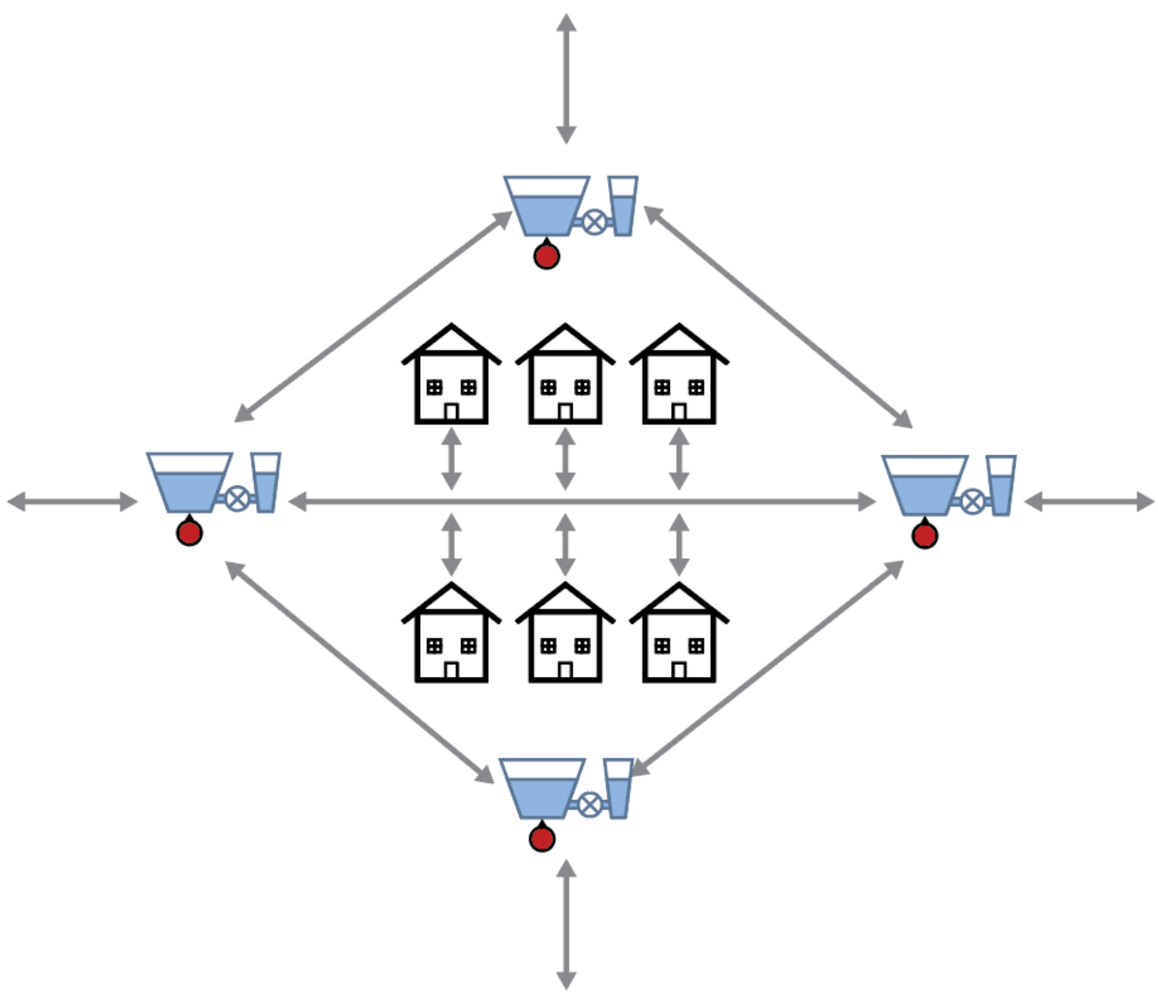


Figure 1:5: BA Analogy

Once the systems are interconnected, the steady state frequency (i.e. water level) is the same throughout. If one BA in the electric grid loses a generating resource, then there may be a drop in frequency. This drop in frequency is less than in an independent system because the overall resource capacity of the interconnected system is much greater. The BA that needs energy could purchase it from others provided that the interconnected system can reliably accommodate the additional flow. Purchasing and/or selling energy between BAs is known as Interchange.

There are two inputs to the BAs control process:[3]

- **Interchange Error:** the net outflow or inflow compared to the scheduled sales or purchases (The units of interchange error are in megawatts.)
- **Frequency Error:** the difference between actual and nominal frequency (The units of frequency error are hertz.)

Frequency bias is used to translate the frequency error into megawatts. Frequency bias is the BAs obligation to provide or absorb energy to assist in maintaining frequency. In other words, if frequency goes low, each BA is asked to contribute a small amount of extra generation in proportion to its system's relative size.

Each BAA usesa common source on the tie-lines with its neighbors for control and accounting. There will be an agreed upon meter at each BA boundary that both neighboring BAs use to perform balancing operations and accounting. Thus, all supply, load, and transmission lines in an Interconnection fall within the metered bounds of a BA.

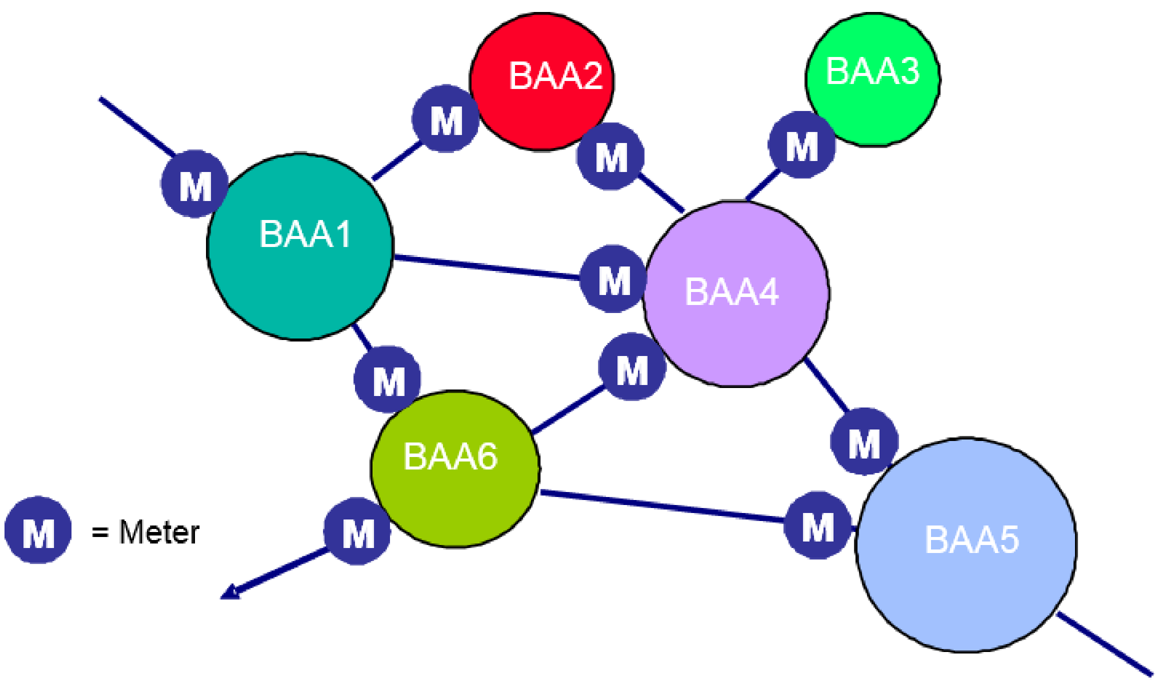


Figure 1:6: Interconnected BA Areas

If the BA is not buying or selling energy,[4] and its supply is exactly equal to the demand and losses within its metered boundary (BAA), the net of its tie line meters will be zero (assuming that the frequency of the system is at nominal). If the BA chooses to buy energy (e.g., 100 Megawatt hours (MWh)), it tells its control system to allow 100 MWh to flow in (by, for example, allowing 100 MW to flow in for one hour). Conversely, the seller will tell its control system to allow 100 MWh to flow out by allowing the corresponding 100 MW to flow out for one hour. If all BAs behave this way, the Interconnection remains in balance and frequency remains stable. Variations in the supply/demand balance

[3] There are two control inputs in multi-BA Interconnections. Texas and Quebec are single BA Interconnections and need only control to frequency.

[4] In most cases, BA's do not buy and sell energy. Transactions now are arranged by wholesale marketing agents that represent load or generation within the BA.

cause frequency to vary from its nominal value. Problems on the grid, such as congestion that prevents the ability to meet schedules, equipment faults that dictate rapid unilateral adjustments of generation, loss of load, incorrect schedules, or poor control cause changes in frequency. Maintaining Interconnection frequency near its nominal value can therefore be thought of as a fundamental indicator of the health of the power system.

Demand and supply are constantly changing within all BAAs. This means that a BA will usually have some unintentional outflow or inflow at any given instant. This mismatch in meeting a BA's internal obligations, along with the small additional "bias" obligation to maintain frequency, is represented via a real-time value called Area Control Error (ACE), with units of MW.

System operators at each BA fulfill their NERC obligations by monitoring ACE and keeping the value within limits that are generally proportional to BA size. This balancing is typically accomplished through a combination of adjustments of supply resources, purchases, and sales of electricity with other BAs, and possibly adjustments of demand.

Conceptually, ACE is to a BA what frequency is to the Interconnection. Over-generation makes ACE go positive and puts upward pressure on Interconnection frequency. A large negative ACE can cause Interconnection frequency to drop. A highly variable or "noisy" ACE tends to contribute to similarly "noisy" frequency. However, the effect of ACE on frequency depends on how ACE is correlated (or anti-correlated) with frequency error. Over-frequency error tends to be made larger when ACE indicates over-generation, and is made smaller when ACE indicates under-generation. Under-frequency error has the opposite relationship. This principle is captured in the way Control Performance Standard 1 (CPS1) measures performance. Accumulation of frequency error over time results in the Interconnection's time error. For better overall Interconnection performance, the Western Interconnection (WI) uses automatic time error correction (ATEC) that allows BAs to make incremental corrections that are caused by under/over performing ACE.

Control Continuum

Figure 1.7 demonstrates that Balancing and frequency control occur over a continuum of time using different resources that have some overlap in timeframes of occurrence.

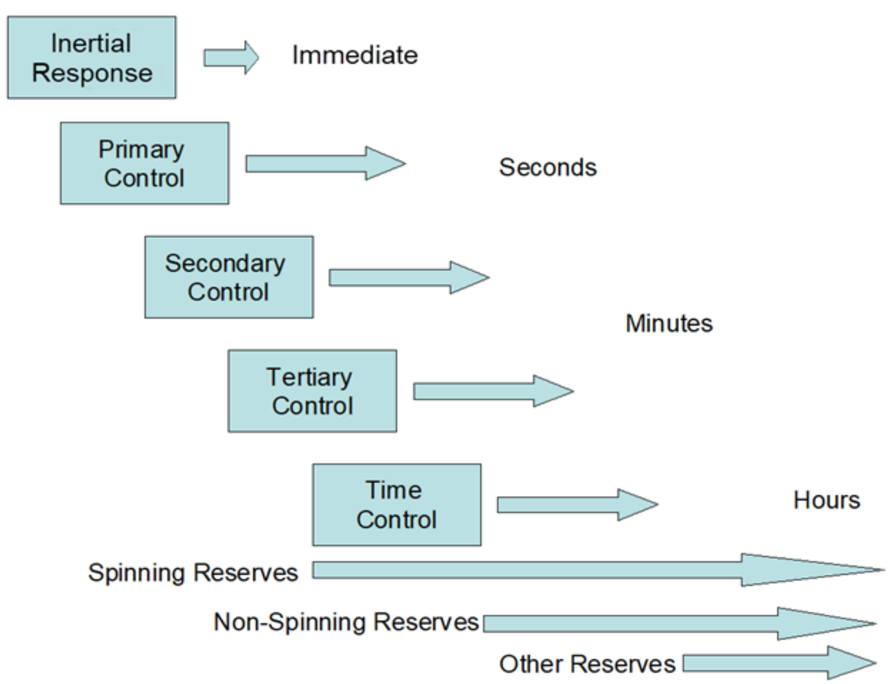


Figure 1.7: Control Continuum

A primary focus of the controls in the control continuum is to maintain nominal frequency under all conditions. One common operating condition is the loss of a (sometimes large) generator. This causes the frequency to drop which then requires the various pieces of the control continuum to recover the frequency to nominal. A stylized example is shown in **Figure 1.8**. The frequency event is somewhat arbitrarily divided into 4 phases: the Arresting Period (when frequency decline is arrested), the Rebound Period (where frequency begins to recover towards nominal), the Stabilizing period (where frequency is stabilized), and the Recovery period (where frequency is recovered to nominal).

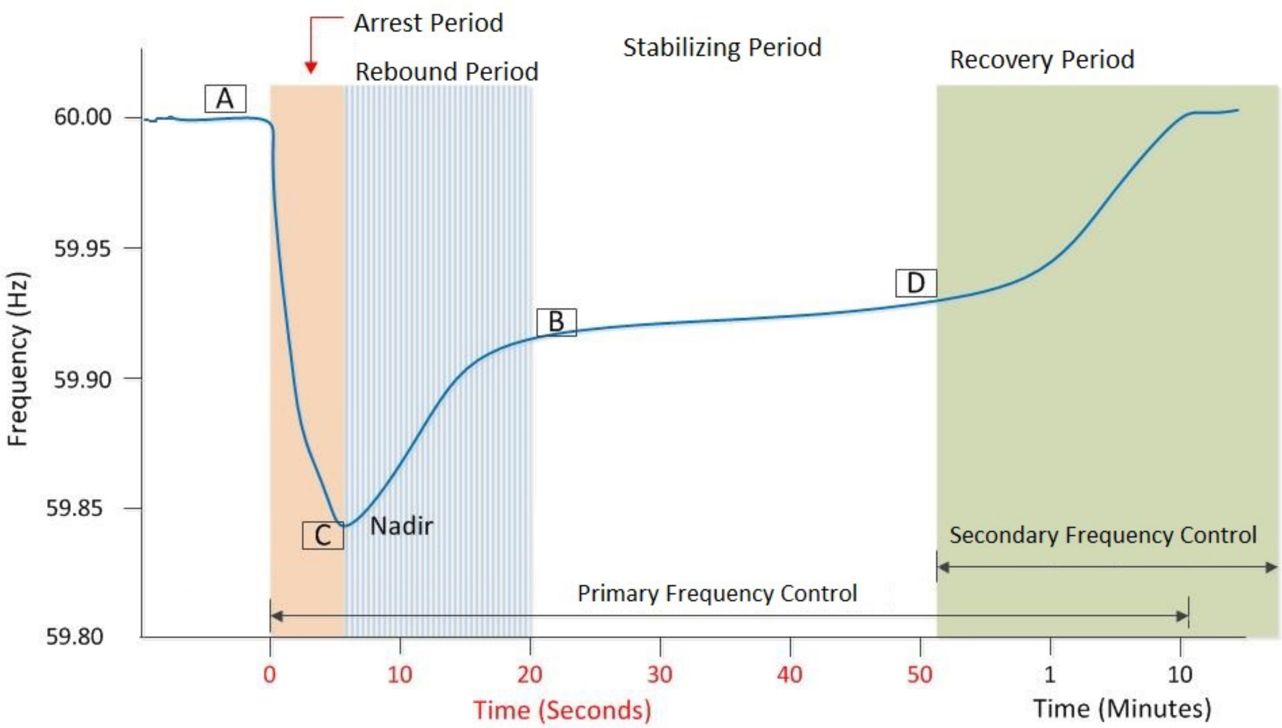


Figure 1.8: Typical Frequency Trend for the Loss of a Generating Resource

Four points of particular interest are shown in **Figure 1.8:** Point A is defined as the pre-disturbance frequency; Point C or Nadir is the maximum deviation due to loss of resource; Point B is defined as the stabilizing frequency and; Point D is the time the contingent BA begins the recovery from the loss of resource.

Inertial Control

Inertial control is more of an effect than an actual control since it is governed by physical principles for most resources and emulated by others. The rotating mass in a typical generator combined with the speed at which it is rotating creates a large amount of stored energy. If a decelerating force is applied (e.g., a large drop in system frequency), energy is transferred from the rotating mass and into the system. One analogy is that of a bicycle wheel and brake. If the wheel is first set spinning and then the brake is applied, the energy from the wheel flows into the braking surfaces. The contact surfaces of the brake will heat up due to the transformation of energy from the wheel into heat.

This is the same principle for the inertia effect in the power system. A sudden increase in the braking force is applied by a decrease in the amount of energy being injected into the system (e.g., losing a large generator or addition of a large load). When the mismatch between injected and consumed energy occurs, energy flows from the rotating masses of the connected resources into the power system. The propagation of this effect across an Interconnection happens within a handful of seconds.

Resources that are not directly coupled via an alternating current connection to the power system (e.g., inverter-based resources) are not typically governed by the same physical principles and therefore might not possess inertia per se from the perspective of the power system. Instead, inertia can be emulated to varying degrees of success by using sensing and control.

Primary Control

Primary control is more commonly known as primary frequency response (PFR). PFR also includes inertial response described under Inertial Control above as well as other types of frequency response actions, as described in the Primary Frequency Control Guideline.[5] PFR is autonomous; it does not require external inputs and begins to occur within the first few seconds following a change in system frequency (disturbance) to stabilize the Interconnection. Frequency response is provided by the following:

- **Governor Action:** Resource governors are like cruise controls for cars. They sense changes in local system frequency and adjust the energy output of the resource to counteract that change. Some resources do not have "governors" per se but instead can emulate governor action to varying degrees of success by using sensing and control actions.
- **Demand Response:** The speed of directly-connected motors in an Interconnection will change in direct proportion to frequency changes. As frequency drops, motors will turn slower and consume less energy.

  Rapid reduction of system load may also be affected by automatic operation of under-frequency relays which interrupt predefined loads within fractions of seconds or within seconds of frequency reaching a predetermined value. Such reduction of load may be contractually represented as interruptible load or may be provided in the form of resources procured as reliability or Ancillary services. As a safety net, percentages of firm load may be dropped by under-frequency load shedding programs to ensure stabilization of the systems under severe disturbance scenarios.

The most common type of a frequency disturbance in an Interconnection is associated with the loss of a generator, causing a decline in frequency; this happens on a daily basis and must be considered. In general, the amount of frequency-responsive, synchronized, and unloaded generation (a.k.a. headroom) in an Interconnection will directly influence the amount of available frequency response because this is the amount of supply that is connected, ready, and able to immediately increase output when needed. Inverter-based resources, especially those coupled with storage or headroom, may also be able to contribute to frequency response.

It is important to note that primary control will not return frequency to nominal, but only arrest and stabilize it. Other control components are used to restore frequency to nominal.

Operating Tip: Frequency response is particularly important during disturbances and islanding situations. System operators should be aware of their frequency responsive resources. Blackstart units must be able to autonomously participate in frequency control; this is especially important during system restoration.

Secondary Control

Secondary control typically includes the balancing services deployed in the "minutes" time frame. However, some resources (e.g., hydroelectric generation or fast electrical storage) can respond faster in many cases. Secondary control is accomplished using the BA's supervisory control and data acquisition (SCADA) and energy management systems (EMSs)[6], and the manual actions taken by the dispatcher to provide additional adjustments. Secondary control also includes some initial reserve deployment for disturbances.

[5] PFC (v 2.0 approved by the Operating Committee 6/4/2019)

[6] Terms most often associated with this are "load-frequency control" or "automatic generation control"

In short, secondary control maintains the minute-to-minute balance throughout the day and is used to keep ACE within CPS bounds and thereby maintain Interconnection frequency close to its scheduled value (usually 60 Hz) following a disturbance. Secondary control is provided by both Operating Reserve – Spinning and Supplemental. During frequency disturbances, secondary control returns the frequency to nominal once primary control has arrested and stabilized it.

The most common means of exercising secondary control is through an EMS's AGC (Automatic Generation Control). AGC operates in conjunction with SCADA systems; SCADA gathers information about an electric power system, particularly system frequency, generator outputs, and actual interchange between the BA and its neighbors. Using system frequency and net actual interchange and knowledge of net scheduled interchange and upcoming changes, it is possible to determine the BA's energy balance (i.e., its ACE) within its Interconnection. Most SCADA systems poll data points sequentially for electric system data, with a typical periodicity of two to six seconds. Because of this, data is naturally slightly out of perfect time sync, but is of sufficient quality to permit balancing and good frequency control.

AGC computes a BAA's ACE from interchange and frequency data. ACE indicates whether a system is in balance or is in need of an adjustment to generation resources. AGC software generally sends signals that cause resources performing secondary control to move to oppose the ACE. Some AGC systems use pulses for raise/lower signals while other AGC systems use MW set points.

The degree of success of AGC in complying with balancing and frequency control is manifested in a BA's control performance statistics that are described in greater detail later in this document.

Tertiary Control

Tertiary Control encompasses actions taken to get resources in place to handle current and future contingencies. Reserve deployment and reserve restoration following a disturbance are common types of Tertiary Control.

Time Control

Frequency and balancing control are not perfect. There will always be occasional errors in tie-line meters whether due to instrument transducer inaccuracy, problems with SCADA hardware or software, or communications errors. Due to these errors and normal load and generation variation, ACE in an Interconnection cannot be maintained at zero. In fact, the average value of ACE over many time frames is non-zero. ACE must be managed such that its magnitude is relatively small. There is no operational reason to force ACE to be an independently randomly distributed variable. This means that frequency is never maintained at exactly 60 Hz for any appreciable length of time and average frequency over time usually is not exactly 60 Hz.

Each Interconnection has a time control process that can be used to maintain the long-term average frequency at 60 Hz. While there are some differences in process, each Interconnection designates a RC as a "time monitor" to provide Time Control.

The time monitor compares a clock driven off Interconnection frequency against the "official time"[7] provided by the National Institute of Standards and Technology. If average frequency drifts, it creates a Time Error between these two clocks. The QI and TI operate so that Time Error is automatically minimized or eliminated while the WI operates to automatically mitigate accumulated Time Error through its ATEC. If the Time Error gets too large in the EI and WI, the Time Monitor may notify BAs in the Interconnection to manually correct the situation.

For example, if frequency has been running 2 mHz high (i.e., 60.002 Hz), a clock using Interconnection frequency as a reference will gain 1.2 seconds in a 10-hour interval:

[7] The Official NIST US Time: https://www.time.gov/

$$\frac{(60.002\ \mathrm{Hz} - 60.000\ \mathrm{Hz})}{60\ Hz} * 10\ hr * 3600 \frac{sec}{hr} = 1.2\ sec$$

If the Time Error accumulates to a predetermined initiation value (e.g., +10 sec in the Eastern Interconnection (EI)) the Time Monitor will send notices for all BAs in the Interconnection to offset their scheduled frequency by -0.02 Hz (Scheduled Frequency = 59.98 Hz). This offset, known as Time Error Correction, will be maintained until Time Error has decreased below the termination threshold (e.g., +6 sec).

A positive offset (i.e., Scheduled Frequency = 60.02 Hz) would be used if average frequency was low and Time Error reached its initiation value (e.g., -10 seconds). Manual time error corrections are no longer required by NERC Reliability Standards but each Interconnection may elect to perform manual time error correction. See the *NERC Time Monitoring Reference Document (Version 5)* on manual time error correction for additional information.[8]

Control Continuum

Table 1.1 summarizes the discussion on the control continuum and identifies the service that provides the control and the NERC standard that addresses the adequacy of the service. Current issues, good practices, and recommendations on balancing and frequency control are discussed later.

Table 1.1: Control Continuum Summary

Control	Ancillary Service/ERS	Timeframe	NERC Measurement
Inertial Control	Inertial Control	0–12 Seconds	N/A
Primary Control	Frequency Response	10–60 Seconds	FRM
Secondary Control	Regulation	1–10 Minutes	CPS1 – DCS - BAAL
Tertiary Control	Imbalance/Reserves	10 Minutes–Hours	BAAL - DCS
Time Control	Time Error Correction	Hours	N/A

[8] https://naesb.org/pdf4/weq_bps062520w1.pdf

Area Control Error (ACE) Review

The CPSs are based on measures that limit the magnitude and direction of the BAs Reporting ACE. The equation for Reporting ACE is as follows:

- Reporting ACE = $(NI_A – NI_S) – 10B (F_A – F_S) – I_{ME}$
- Reporting ACE (WI) = $(NI_A – NI_S) – 10B (F_A – F_S) – I_{ME} + I_{ATEC}$

where:

- NI_A is Actual Net Interchange,
- NI_S is Scheduled Net Interchange,
- B is BA Bias Setting
- F_A is Actual Frequency,
- F_S is Scheduled Frequency,
- I_{ME} is Interchange (tie line) Metering Error
- I_{ATEC} is ATEC (WI only)

NI_A is the algebraic sum of tie line flows between the BA and the Interconnection. NI_S is the net of all scheduled transactions with other BAs. In most areas, flow into a BA is defined as negative; flow out is positive.

The difference between net actual interchange and net scheduled interchange (N_{IA} - N_{IS}) represents the so-called "inadvertent" error associated with meeting schedules without consideration for frequency error or bias. If it is used by itself for control, it would be referred to as "flat tie line" control.

The term 10B (F_A - F_S) is the BAs obligation to support frequency. B is the BAs frequency bias stated in MW/0.1 Hz (B's sign is negative). The "10" converts the bias setting to MW/Hz. F_S is normally 60 Hz but may be offset ± 0.02 Hz for time error corrections. Control using "10B (F_A - F_S)" by itself is called "flat frequency" control.

I_{ME} is a correction factor for meter error. The meters that measure instantaneous[9] flow are not always as accurate as the hourly meters on tie lines. BAs are expected to check the error between the integrated instantaneous and the hourly meter readings. If there is a metering error, a value should be added to compensate for the estimated error; this value is I_{ME}. This term should normally be very small or zero.

I_{ATEC} is an ACE offsetting term for automatic timer error correction in the WI. BAs correct for any delta Time Error that they are responsible for each hour.

Reporting ACE is calculated in Real-time, at least as frequently as every six seconds, by the responsible entity's Energy Management System (EMS) predominantly based on source data automatically collected by that system. Also, the data must be updated at least every six seconds for continuous scan telemetry and updated as needed for report-by-exception telemetry. See the Integrating Reporting ACE Guideline for more detail on the components of ACE and the calculation frequency.

Here is a simple example: Assume a BA with a bias of -50 MW/0.1 Hz is purchasing 300 MW. The actual flow into the BA is 310 MW. Frequency is 60.01 Hz. Assume no time correction, metering error or ATEC.

[9] Instantaneous, as used herein, refers to measurements that are as close to real-time as is possible within the limits of data acquisition and conversion equipment.

- ACE = (-310 – -300) – 10*(-50) * (60.01 – 60.00) = (-10) – (-5) = -5 MW.

The BA should be generating 5 MW more to meet its obligation to the Interconnection. Even though it may appear counterintuitive to increase generation when frequency is high, the reason is that this BA is more energy-deficient at this moment (-10 MW) than its bias obligation to reduce frequency (-5 MW). The decision on when or if to correct the -5 MW ACE would be driven by CPS compliance.

A distinction can be drawn between reporting ACE, which measures the effect of a BA on the Interconnection, and Control ACE. At any given time, a BA might use a control ACE that is different from reporting ACE because AGC resources respond to control ACE, and this difference might be used, for example, to cause AGC resources to assist in "paying down" accumulated inadvertent energy or some other purpose.[10]

Bias (B) vs. Frequency Response (Beta)

There is often confusion in the industry when discussing frequency bias and frequency response. Even though there are similarities between the two terms, frequency bias (B) is not the same as frequency response (β).

Frequency response, defined in the NERC Glossary,[11] is the mathematical expression of the net change in a BA's net actual interchange for a change in Interconnection frequency. It is a fundamental reliability characteristic provided by a combination of governor action and demand response. Frequency response represents the actual MW contribution by inertial control and primary control to stabilize frequency following a disturbance.

Bias is an approximation of β used in the ACE equation. Bias (B) is designed to prevent AGC withdrawal of frequency support following a disturbance. If B and β were exactly equal, a BA would see no change in ACE following a frequency decline even though it provided a MW contribution to stabilize frequency.

Bias and frequency response are both expressed as negative numbers. In other words, as frequency drops, MW output (β) or desired output (B) increases. Both are measured in MW/0.1 Hz

Important Note: When people talk about frequency response and bias, they often discuss them as positive values (e.g., as "our bias is 50MW/0.1Hz"). Frequency response and bias are actually negative values.

Early research (Cohn) found that it is better to be over-biased (i.e., absolute value of B greater than the absolute value of β) than to be under-biased.

[10] Bilateral or Unilateral payback of inadvertent is not allowed in the WI. ATEC is used by BAs in the WI to control primary inadvertent accumulation while automatically correcting time error.

[11] Select from list found at: https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf

Chapter 2: Primary Control

Background

Primary control relates to the response to a frequency deviation by generator governors (aka. speed controls) and inertia that helps stabilize Interconnection frequency whenever there is a change in load-resource balance. Primary control is provided in the first few seconds following a frequency change and is maintained until it is replaced by AGC action (secondary control). Frequency response (or Beta), which also includes rotational inertia response from resources and load response from frequency dependent loads, is the more commonly used term for primary control. Beta (β) is defined by the total of all initial responses to a frequency excursion.

Figure 2.1 shows a trace of the WI's frequency that resulted from a generating unit trip. The graph plots frequency from 5 seconds prior to the loss of a large generator until 60 seconds thereafter.

NERC references three key events to describe such a disturbance. Value A is the pre-disturbance frequency, typically close to 60 Hz. Point C is the maximum excursion point, commonly referred to as the Nadir, which occurs about 10 seconds after the loss of generation in this WI example. Value B is the settling frequency of the Interconnection.

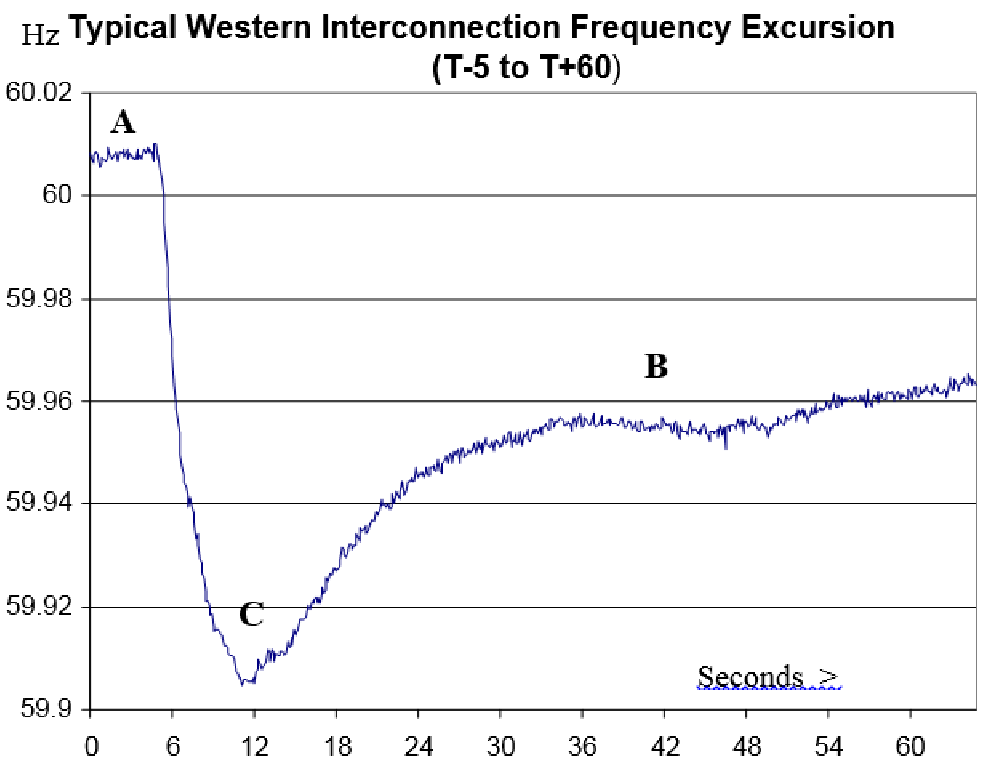


Figure 2.1: WI Frequency Excursion

As discussed earlier, there are two groups of "resources" that arrest a decline in frequency due to a loss of generation:

- A given portion of Interconnection demand is composed of motor load, which draws less energy when the motors slow down due to the lower frequency.
- Generators have governors that act much like cruise control on a car. If the generators on the Interconnection start to slow down with the frequency decline, their governors supply more energy to the generators' prime movers in order to speed them back up to nominal. The sensitivity of this response is controlled by the governor droop setting.

Inertial Response

Inertia quickly and autonomously opposes changes to both under and over frequency events. Having a large amount of inertia is useful for smoothing out power system frequency fluctuations. It is inertia combined with the response of frequency sensitive demand that determines how quickly the frequency decays following the loss of a large supply resource like a large generator or importing direct current tie-line. In an interconnection, more inertia leads to a slower drop in frequency, giving time for the other components of the control continuum to act in order to arrest, stabilize, and then recover frequency. In some sense, the inertia of the power system can be controlled by adjusting the amount and type of generators that are on-line. Inertia is commonly described in units of seconds: the energy that is stored is normalized by the electrical "size" of the resource. Since stored energy is a function of the square of the speed of rotation, low rotating mass, faster spinning resources might store more energy, yet they typically decelerate faster (thereby injecting more energy). These lighter and faster resources' contribution to slowing the fall of frequency is more "front-loaded" and they have smaller normalized inertia values than large-rotating-mass slow-spinning resources that have slower energy injection profiles. Faster response is also not always better because of interaction effects that can cause instability where resources might "bounce" in opposite directions.

For a discussion and graphical representation on how inertia opposes changes in under and over frequency excursions, see the *NERC Frequency Response Standard Background Document,* dated November 2012.[12]

Generator Governors (Speed Controls)

The most fundamental, front-line control of frequency in ac electric systems is the action of generator governors. Governor's act to stabilize frequency following disturbances and act as an immediate buffer to load-resource imbalance. Governors operate in the time frame of milliseconds to seconds and operate independently from and much faster than system operator actions or those of AGC. They protect from the effects of frequency when too high, but the vast majority of their benefit comes from assisting when frequency has dropped too low, especially in cases where loss of generation causes abrupt decreases in Interconnection frequency.

Without governor action, loss of generation would result in frequency that would not stabilize until the load reduced to a point that matched the remaining generation output. As mentioned previously some load is reduced when the frequency is reduced mostly due to directly connected motors slowing down and consuming less power. This supply/demand balance point could occur at very low frequency and could result in cascading outages or complete frequency collapse, a very undesirable outcome in terms of the cost to society and potential equipment damage.

The combination of inertial response, governor response and load response – are the "beta" (β), or frequency response characteristic, of a BAA. This is the characteristic that AGC attempts to mimic in its use of the frequency bias ("B") parameter in determining ACE. The net of all BA frequency responses manifests as the Interconnection frequency response.

Droop

Governors cause generators to try and maintain a constant, stable system frequency (60 Hertz in North America). They do this by constantly governing (modulating) the amount of mechanical input energy to the shaft of the electric generator. The degree of this modulation is called "droop" and is measured in percent of frequency change to cause full generator capability to be exerted against the frequency error. A typical slope is 5%, meaning that the full output of the generator would be used (or attempt to be used) to counteract the frequency error if frequency error is 5% or 3 Hz. It should be noted that smaller droop percentages indicate increased sensitivity of response, e.g., a generator with a 4% droop would attempt to go to full output if the frequency changed by 2.4 Hz. Frequency errors are more typically in the range of 0.01% (.06 Hz, or 60 mHz), so governor action usually is a much smaller fraction of a unit's output capability. It must also be recognized that, while most generators can reduce output considerably in response

[12] https://www.nerc.com/comm/OC/RS%20Landing%20Page%20DL/Related%20Files/Bal-003-1_Background_Document_Clean_20121130.pdf

to their governor's actions, increasing output is more problematic since many generators may already be near the top of their output capability when low frequency causes their governor to request more output. Thus, if there is no headroom available on a generator's output, the governor will be able to do little to increase that output and help stabilize low frequency.

Deadband

The second general characteristic of governors is "deadband." This means that the governor ignores frequency error until it passes a threshold. When frequency error exceeds the threshold (which should not exceed the maximum deadband setting per Interconnection recommended in the NERC Reliability Guideline-Primary Frequency Control), the governor becomes active. It is worth noting that the deadband may be larger for older mechanical-style governors, and may have mechanical lash associated with it.

The calculated unit MW output change with a droop setting of 5% and deadband setting of 36 mHz based on the total resource capacity is shown in Figure 2.2

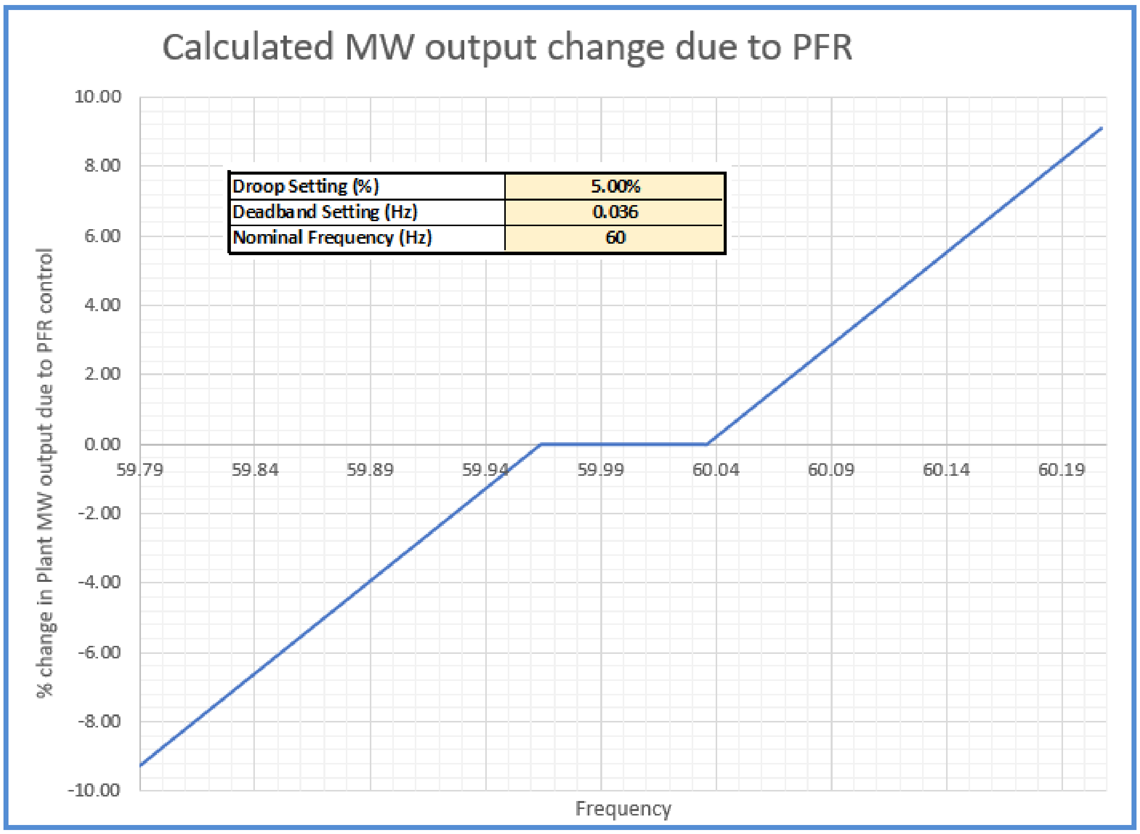


Figure 2.2: Calculated Resource %MW Output Change due to PFR

Calculating Frequency Response

Prior to current Reliability Standard requirements governing frequency response[13], calculation of frequency response was addressed by the NERC *Frequency Response Characteristic Survey Training Document*,[14] which included a form to guide the calculation for a given event. The calculation of the Frequency Response Characteristic (FRC) for a BA is to divide the change in Net Interchange Actual (NI_A) from pre-event (A point, see Figure 1.8 above) to the stabilizing period (B point, ~20-52 seconds after the event) by the change in interconnection frequency from pre-event to the stabilizing period. Although the terms in the FRC Training Document have changed over the years (e.g., Control Area is now Balancing Area), the calculation remains the same. This is often referred to as the A to B frequency response. With the advent of faster scanning tools over the years (e.g., Phasor Measurement Units), a similar response calculation can be made from the A point to the C point (nadir, if a generation loss or apex, if a load loss) of the frequency event.

Important Concept: The frequency response will normally be a negative value, reflecting the inverse relationship between the increase in MW output in response to the decrease in interconnection frequency for a frequency decline (e.g., a generator trip), or vice versa for a frequency increase (e.g., a load loss).

Under the current Reliability Standard requirements, the selection of events for evaluation and the calculation forms used to determine response are prescribed by the Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard[15], the Reliability Standard itself, its attachment and associated forms.

Frequency Response Profiles of the Interconnections

The amount of frequency decline from a generator trip varies based on a number of factors, e.g. time of day, season, and Interconnection loading. The observed frequency responses of the North American Interconnections as documented in the *2018 NERC State of Reliability* report are as follows:

- EI -2,103 MW / 0.1Hz
- TI -674 MW / 0.1 Hz
- WI -1,539 MW / 0.1 Hz
- QI -599 MW / 0.1 Hz

Important Note: These values are not normalized to adjust for starting frequency and/or resource loss size.

As noted above, the negative sign means there is an inverse relationship between generation loss and frequency. In other words, a loss of 1,000 MW would cause a frequency change (A to B) on the order of:

- EI -0.048 Hz
- TI -0.148 Hz
- WI -0.065 Hz
- QI -0.168 Hz

Conversely, if 1000 MW of load were lost in an Interconnection, the resulting frequency increase would be similar in magnitude as listed above.

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[13] As of the release date of this document, the current applicable Reliability Standard is BAL-003-1.1

[14] https://www.nerc.com/comm/OC/RS%20Agendas%20Highlights%20and%20Minutes%20DL/Frequency_Response_Characteristic_Survey_19890101.pdf

[15] https://www.nerc.com/comm/OC/BAL0031_Supporting_Documents_2017_DL/Procedure_Clean_20121130.pdf

Figure 2.3 is a typical trace following the trip of a large generator in three of the Interconnections. Notice that governors in the East do not provide the "Point C to B" recovery of frequency as they do in the other Interconnections. The rate of frequency decline is much slower primarily due to its size, so frequency slowly drops until sufficient response stops the decline. In the early 2000s, there was typically a post-event decline in frequency, but this effect has been occurring less often.

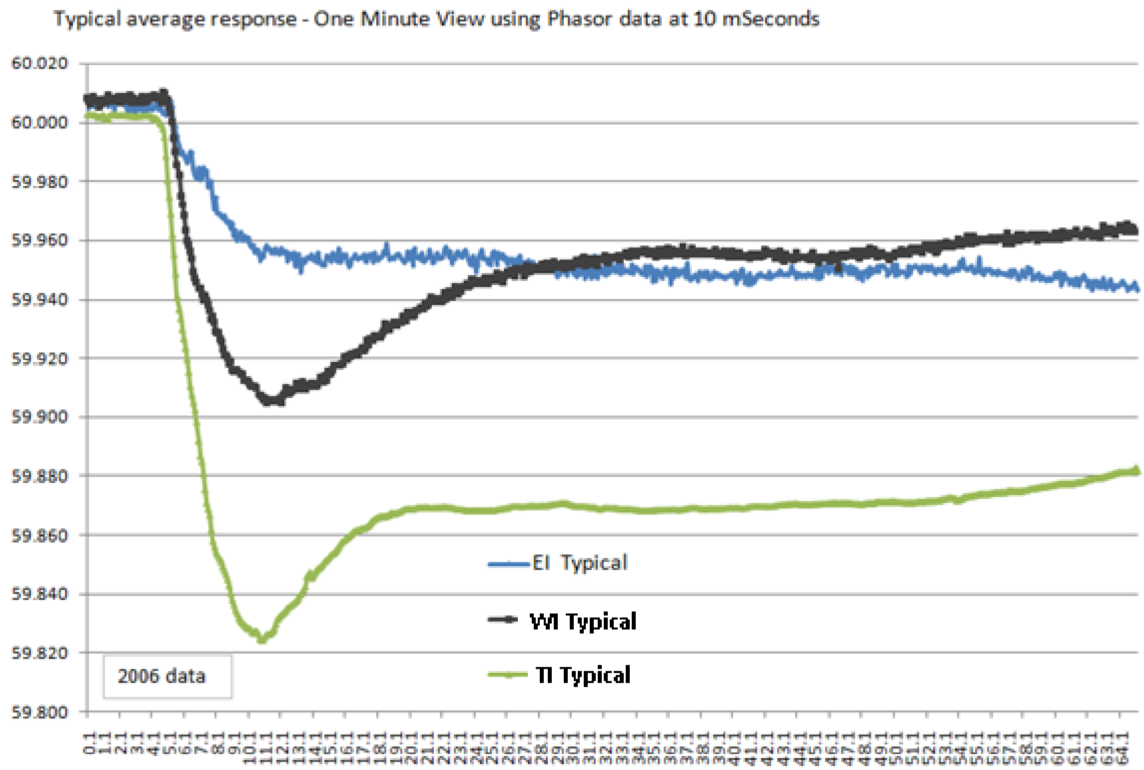


Figure 2.3: Typical Frequency Excursions

<u>Important Concept:</u> Following a large generator trip, frequency response will only stabilize the frequency of an Interconnection, arresting its decline. Frequency will not recover to scheduled frequency until the contingent BA replaces the lost generation through AGC and reserve deployment.

Figure 2.4 Shows the frequency at measured at various locations across the EI after a large generator trip. Note that the frequency disturbance is a chaotic event with complex dynamics, including fast transients bouncing about a much longer term trend. Also note that the time-scale tick-marks are every 5 seconds: the whole event has reached a stabilized frequency within 20 seconds.

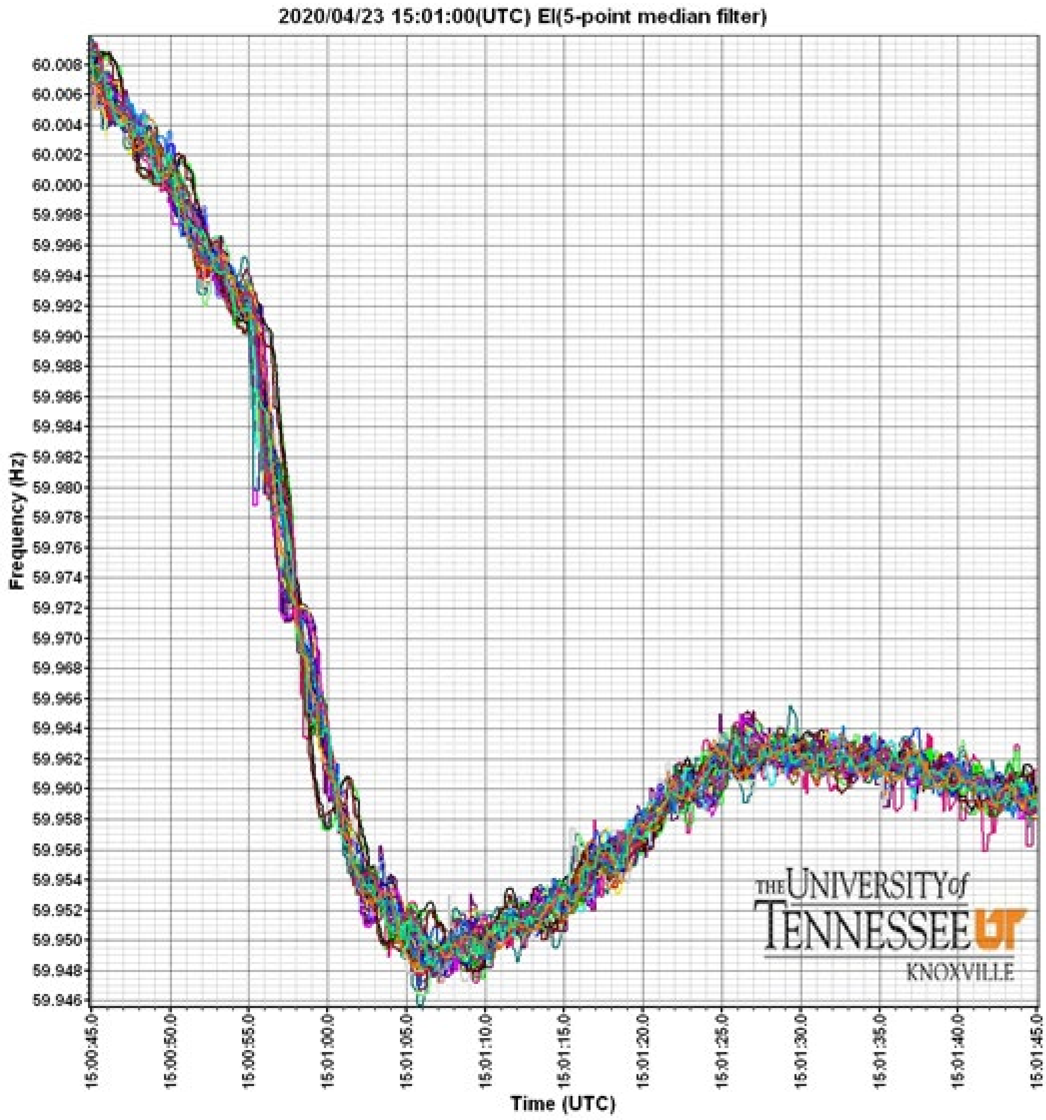


Figure 2.4: Frequency Excursion Measured at various locations in the EI

Annual Bias Calculation

The value in a BA properly stating its bias is to ensure its AGC control system does not cause unnecessary over-control of its generation.

The NERC RS posts quarterly lists of excursions that are available to the industry for everyone's use for evaluating frequency response during the year. The subcommittee refines these quarterly lists into an official event list that is used in BAL-003 FRS forms.

Guidelines the RS uses in selecting and evaluating events for calculating bias and BAL-003 performance include the following:

- Events are dispersed throughout the year to get a good representation of "average" response.
- Pick frequency excursions large enough to actuate generator governors.
- The events should be relatively clean and generally have continuous drop from A to C.

- Starting frequency should be relatively stable and close to 60 Hz.

Estimating Load's Frequency Response

As discussed previously, motor load provides frequency response to the Interconnection. The rule of thumb is that this response is equal to 1–2% of load. Techniques have been developed to observe approximately how much "load" frequency response a BA has available. This technique is explained in **Figure 2.5**.

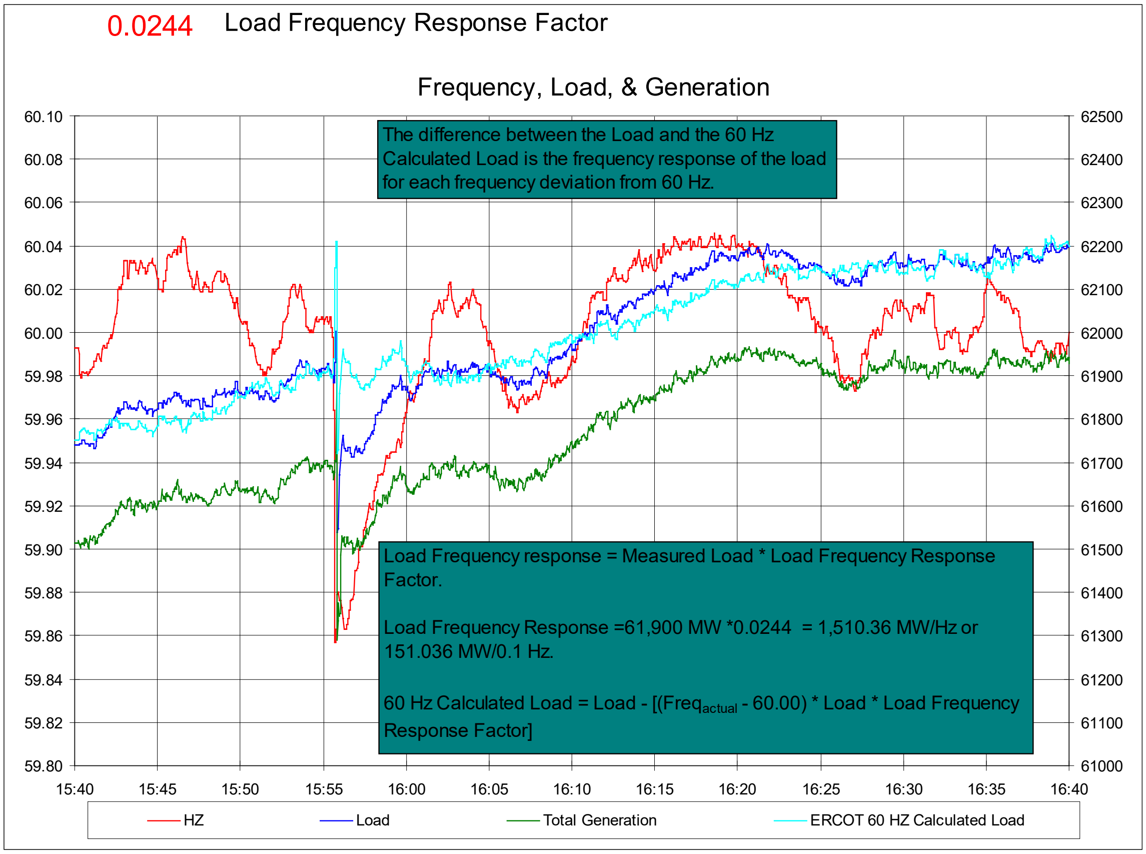


Figure 2.5: Observing Frequency Response of Load

The cyan trend in **Figure 2.5** above represents how much load would exist if frequency could be controlled to exactly 60.000 Hz all the time. The difference between the measured load, blue trend, and the cyan trend is the frequency response of load. For this event, a 759 MW resource was lost producing a frequency deviation of -0.118 Hz. This calculates to be

$$\frac{759\ MW}{0.118\ Hz * \left(\frac{10 * 0.1\ Hz}{Hz}\right)} = \frac{643\ MW}{0.1\ Hz} \text{ of frequency response.}$$

Of this response, 151.036 MW/0.1 Hz was provided by the load by multiplying the load by 0.00244, leaving the remainder (492.184 MW/0.1 Hz) provided by resource governor response. The post contingency total generation settled at 61,510 MW a difference of 178.222 MW below the pre-contingency generation. The generation-to-load mismatch post event is 178.222 MW plus replacement of the 580.777 MW of governor response (492.184 * 1.18 = 580.777) that will be withdrawn as frequency returns to 60.00 Hz. If this BA's bias in the ACE equation had been set exactly at 643 MW/0.1 Hz, ACE would equal -759 MW at the B point of this event. AGC would dispatch 759 MW to replace the frequency response of the governors and load, returning the Interconnection to balance at 60.00 Hz. This example is of a "single" BA Interconnection but the math works for multiple BA Interconnections as well.

By observing multiple events and adjusting the factor to produce a "60 Hz Load" value that maintains the pre- and post-event slope of load, a proper value can be determined. Larger deviation frequency events are beneficial to get a clear observation in addition to looking at many events. A factor between 0.010 and 0.025 would be reasonable depending on the ratio of motor load vs. non-motor load within the BAA boundaries.

The key points of primary control are as follows:

- Steady-state frequency is common throughout an Interconnection.
- If frequency is off schedule, generation is not in balance with total load.
- Arresting frequency deviations is the job of all BAs. This is achieved by provision of frequency response through the action of operating governors on generation and other resources able to provide frequency response (e.g., controllable load, storage, etc.).
- Frequency response is the sum of a BAs inertial response, natural load response and governor response of generators to frequency deviation within the BA Area.
- Frequency response arrests a frequency decline but does not bring it back to scheduled frequency. Returning to scheduled frequency occurs when the contingent BA restores its load-resource balance by using secondary control.
- Generators should be operated with their governors free to assist in stabilizing frequency.
- Frequency control during restoration is extremely important. That is why system operators should have knowledge of the generators' governor response capabilities during black start.
- All BAs have a frequency response characteristic based on the governor response of their units and the frequency-responsive nature of their load.
- The amount and rate of frequency deviation depends on the amount of imbalance in relation to the size of the Interconnection.
- Frequency bias is a negative number expressed in MW/0.1Hz.
- The preferred way to calculate frequency response is to observe the change in BA output for multiple events over a year.
- Under BAL-003-1.1 BA's should set its fixed bias to no less than the 100–125% of its natural frequency response or its percentage share of 0.9% of the Interconnection's non-coincidental peak load based upon all of the BAs within an Interconnection's non-coincident peak load values (whichever method is greater in absolute terms).
- BAs are allowed to employ variable frequency bias that more accurately reflects real-time operating condition.
- Governors were the first form of frequency control and remain in effect today; they act to oppose large changes in frequency.
- AGC supplements governor control by controlling actual tie flows and maintaining scheduled interchange at its desired value. It performs this function in the steady-state, seconds-to-minutes time frame after transient effects, including governor action, have taken place. If bias is greater than actual frequency response, AGC will supplement this response.
- ACE, the main input to AGC, requires frequency and energy interchange data (both actual and scheduled).
- While frequency response was declining in the 1990s, actions taken by the Industry appear to have stabilized the trend.
- BA or Interconnection frequency response should be measured for two reasons:
  - To gauge the area response to frequency deviations.

- As a basis for setting B.

Chapter 3: Secondary Control

Background

Secondary control is the combination of AGC and manual dispatch actions to maintain energy balance and scheduled frequency. In general, AGC utilizes maneuvering room while manual operator actions (e.g., communication to generators, purchases and sales, load management actions) keep repositioning the BAA so that AGC can respond to the remainder of the load and interchange schedule changes. NERC CPSs are intended to be the indicator of sufficiency of secondary control.

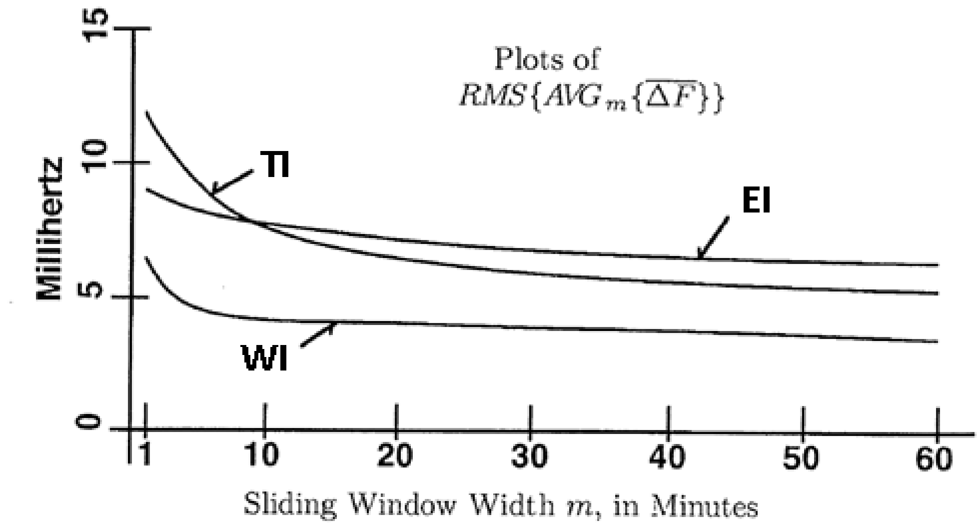
Maintaining an Acceptable Frequency Profile

One indicator of proper secondary control action is the distribution profile of steady-state Interconnection frequency. When the transition was made from the "A" criteria to CPS in 1997, the directive of the NERC Operating Committee was to not allow frequency variation to become any greater than it had been in the past. One measure of this is the root mean square (RMS) of frequency error from schedule. This by itself, however, is a measurement over an indefinite term and may not reveal problems at all averaging intervals. To adequately measure the frequency profile of an Interconnection, a statistical method was adopted in which period averages of RMS frequency error were measured and cataloged for periods of a large number of different values. In other words, the average of rolling N-minute RMS averages was computed for many values of N. This results in a defining profile as shown in **Figure 3.1** and **Figure 3.2.** Although other values could have been selected and ideally ALL values should be considered, the decision was made that the general profile would be maintained if the profile was anchored at two points in time (originally 1 minute and 10 minutes).

To set values for frequency performance, each Interconnection's frequency error was observed by using the above method, and each one was characterized, particularly at their 10-minute interval average RMS frequency deviation from schedule. The EI measured 5.7 mHz at the 10-minute point. The 1-minute point used to set the CPS standard was derived from an "ideal" error characteristic by the ratio of square roots. This yields $5.7 * \sqrt{(10)} = 18.025$ mHz. This value was rounded to the value in use today for the East, 18 mHz.

The same technique was used for the WI and TI. It is important to realize that CPS1 performance is only measured at this one "slice" (one-minute averaging) of the Interconnection's frequency error characteristic. Because of this, there is no assurance that frequency variation will be constrained at other averaging points or converge on the ideal characteristic and become more random.

Initially, a 10-minute metric called CPS2 was developed to keep average ACE within specific bounds. CPS2 was originally used to help prevent excessive transmission flows due to large values of ACE. The problem with CPS2 was that it was not dependent on ACE's impact on frequency. Additionally, CPS2 could cause control actions that moved against frequency. If a BA had very bad performance in one direction for five minutes, the BA could correct this by having equally bad performance in the opposite direction for the next five minutes. Finally, ACE could be totally unbounded for 10% of the month and it didn't matter whether it was 1 or 1000 MW over the limit. CPS2 did not provide the correct signal for maintaining frequency. Ultimately, the industry adopted a frequency-sensitive longer term (i.e., 30 minute) measure called the BA ACE Limit (BAAL).



Frequency experience in the subject interconnections. Each ordinate point on these curves is the RMS value of the averages of $\overline{\Delta F}$ in windows of width m moved across the data string.

Figure 3.1: Interconnections with CPS actual-measured ΔF "period average"

Figure 3.1 Illustrates the actual-measured ΔF "period average" characteristic of the Interconnections with CPS was designed (EPRI report RP-3550, August, 1996). Note that these curves are flatter than what was ultimately selected as the epsilon limits in CPS1. The reason for this is that the standard needed to bound acceptable performance but not raise the bar and make it difficult to comply. For example, the 1-minute frequency variation in the East was about 10 mHz; if 10 mHz were chosen as Epsilon 1 in the East as opposed to the 18 mHz that was actually selected, it would mean that half the BAs in the East would have been out of compliance when the standard became active. Random (i.e., non-coincident) behavior of BAs in total is important in the above assumptions because the curves from which epsilon 1s were extrapolated start to deviate from the shape and predictability of the curves used to derive them as behavior becomes coincident (i.e., behaviors happening at the same time). Another way of saying this is that it becomes less and less valid to try to control frequency and measure performance at just one point on the sliding window continuum as coincidence creeps in. Prior to the adoption of the BAAL, the Interconnections would see wider frequency swings at specific times of day, particularly in the low direction. The swings, due primarily to load changes and large block Interchange Schedules, could occur under CPS2. The number and magnitude of frequency swings were reduced through a combination of tools that identified the contributing BAs as well as the adoption of BAAL.

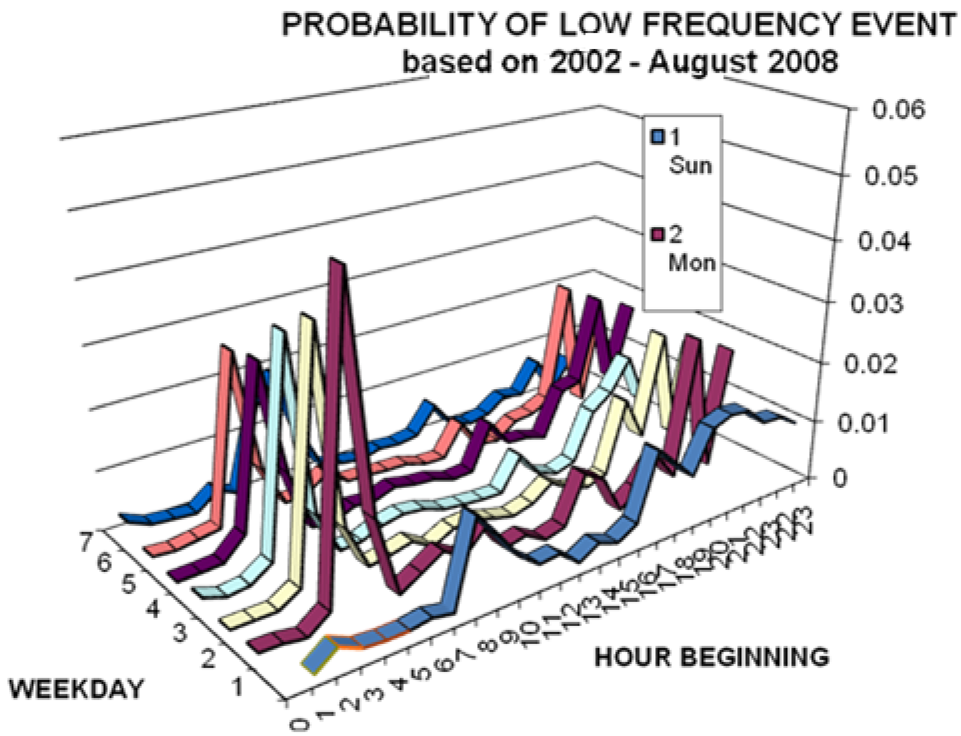


Figure 3.2: Probability Distribution for Low-Frequency Events vs. Time of Day

Control Performance Standard 1

In simple terms, CPS1 assigns each BA a share of the responsibility for control of steady-state Interconnection frequency. The amount of responsibility is directly related to BA frequency bias.

As mentioned previously, ACE is to a BA what frequency is to the Interconnection. Over-generation makes ACE go positive and frequency increase while negative ACE "drags" on Interconnection and decreases frequency. "Noisy" ACE tends to cause "noisy" frequency. CPS1 captures these relationships using statistical measures to determine each BA's contribution to such "noise" relative to what is deemed permissible.

The CPS1 equation can be simplified as follows:

- CPS1 (in percent) = 100* [2 – (a Constant[16])* (frequency error)*(ACE)]

Frequency error is deviation from scheduled frequency, normally 60Hz. Scheduled frequency is different during a time correction, but for the purposes of this discussion, assume scheduled frequency is 60 Hz.

Refer to the equation above. Any minute where the average frequency is exactly on schedule or BA ACE is zero, the quantity ((frequency error)*(ACE)) is zero. Therefore, CPS1 = 100* (2-0), or 200%. This is true whenever frequency is on schedule or ACE is zero.

For any one-minute average where ACE and frequency error are "out of phase," CPS1 is greater than 200%. For example, if frequency is low, but ACE is positive (tending to correct frequency error), the BA gets extra CPS1 points.

[16] The size of this constant changes over time for BAs with variable bias, but the effect can be ignored when considering minute-to-minute operation. It is equal to -10 * B / ε_1^2

Operating Tip: Frequency is generally low when load is increasing and high when load is dropping. Anticipating and staying slightly "ahead of the load" and on the assistive side of frequency correction with your generation will give your BA high CPS1 scores over the long run.

Conversely, if ACE is aggravating the frequency error, CPS1 will be less than 200%. CPS1 can even go negative.

TI and QI Note: The TI and QI operate as single BA's. ACE for a single BA Interconnection will always be "in phase" with frequency error; refer to the ACE review for verification. This means the largest CPS1 these BA's can achieve is 200%. This occurs whenever ACE or frequency error is zero. CPS1 for these BA's is a function of "frequency squared."

The CONSTANT in the equation above is sized such that the BA will get a CPS1 of 100% if the BA's ACE is proportionally as "noisy" as a benchmark frequency noise. The minimum acceptable rolling twelve-month score for CPS1 is 100%.

When CPS was established, each Interconnection was given a target or benchmark "frequency noise." This target noise is called Epsilon 1(ε1). Epsilon 1 is nothing more than a statistician's variable that means the RMS value of the one-minute averages of frequency.

The target values (in mHz of frequency noise) for each Interconnection are shown in **Table 3.1** below. The NERC RS monitors each Interconnection's frequency performance and can adjust the ε1 values should an Interconnection's frequency performance decline.

Table 3.1: Target Values of "One Minute Frequency Noise"

Interconnection	Epsilon 1 (ε1)
Eastern	18.0 mHz
Quebec	21.0 mHz
Western	22.8 mHz
Texas	30.0 mHz

The Epsilon 1 target initially set for each Interconnection was on the order of 1.6 times the historic frequency noise. This means a typical BAs performance would be around 160% for CPS1. If every BA in an Interconnection were performing with a CPS1 of 100%, it would result in an observed Interconnection frequency performance of ε1 (i.e.18mHz in the East).

Let's review how CPS1 data can be applied to measure the adequacy of control performance and the deployment of resource-provided services to meet load. NERC previously referred to these resources as interconnected operating services (ERSs). More recently, the term essential reliability services is used. These align somewhat to what FERC calls "ancillary services."

Figure 3.3 depicts ACE charts for one hour for four different BAs. Compare the charts for BAs 1 and 2. Both BAs show good performance for the hour. The difference between them is that the load in BA 2 is "noisier."

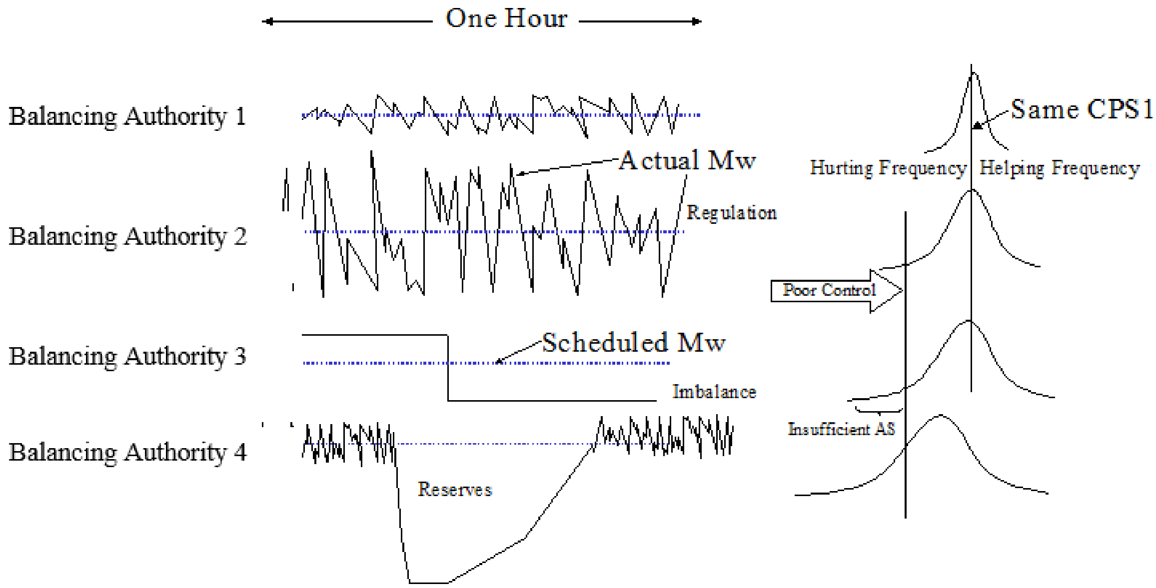


Figure 3.3: ERS/Ancillary Service Measured via CPS

The distributions to the right of the ACE charts show the individual one-minute CPS1 for both BAs for the hour. If frequency followed a normal pattern whereby it fluctuated +/- a few mHz from 60 Hz, the CPS1 curves for BA 1 and 2 would look like the distributions to the right of their ACE charts. Both curves would have the same average (about 160 percent CPS1), but BA 2's curve would be "wider."

Even though the average effect of BA 1 and 2 on the Interconnection is the same, BA 2 sometimes places a greater burden on the Interconnection as demonstrated by the size of the "left hand tail" of the CPS1 curve. A very long left tail implies poor control of some type (regulation in this case).

Now look at BA 3. It is a "generation only" BA that is selling 100 MW for the hour. The problem is that it is meeting this requirement by generating 200 MW for the first 30 minutes and 0 MW for the last half hour. Again, if frequency conditions are normal, half the time the BA will be helping frequency back towards 60 Hz and half the time the BA will be hurting frequency. This means the BA will get an "Interconnection average" CPS1 score of about 160% for the hour. The graph of its CPS1 for the hour will have wider tails, much like BA 2. The underlying problem in this case is imbalance, not regulation.

The ACE chart for BA 4 shows that a generator tripped offline during the hour. If the CPS1 one-minute averages are plotted, the curve will also have wider tails. If the unit that was lost was large, the curve will be "skewed" to the left even further. This is because the unit loss will pull frequency down while ACE is a large negative value.

In each case above, there was a deficiency in one of the energy-based ERSs. The "left tail" of the underlying CPS1 curve captured each situation.

Balancing Authority ACE Limit

In simple terms, BAAL assigns each BA a share of the responsibility for control of steady-state Interconnection frequency. The amount of responsibility is directly related to BA frequency bias and any deviation of Interconnection frequency from the Interconnections scheduled frequency.

The BAAL is calculated from the clock minutes averages of the data as follows:

Frequency Trigger Limits:

- FTL_{High} = Scheduled Frequency + 3*ε1
- FTL_{Low} = Scheduled Frequency - 3*ε1

As an example, for the EI (where epsilon1 = 0.018 mHz) and when the Interconnection is not in a time error correction (TEC) the FTL's are:

- FTL_{High} = 60.054 Hz
- FTL_{Low} = 59.946 Hz

Calculating the BAAL limits when actual frequency <> scheduled frequency:
As an example, for a BA with a frequency bias Setting = -1000MW/0.1Hz

- $BAAL_{Low} = (-10 * B * (FTL_{Low} - F_S)) * ((FTL_{Low} - F_S)/ (F_A-F_S))$
- $BAAL_{Low} = (-10*-1000* (59.946 – 60)) * (59.946 – 60)/ (F_A – 60))$

- $BAAL_{High} = (-10 * B * (FTL_{High} - F_S)) * ((FTL_{High} - F_S)/ (F_A-F_S))$
- $BAAL_{High} = (-10*-1000* (60.054 – 60)) * (60.054 – 60)/ (F_A – 60))$

Results with actual varying frequency are shown in Table 3.2.

Table 3.2: Varying Frequency Results

Actual Frequency	$BAAL_{High}$	$BAAL_{Low}$
60.09	324	NA
60.081	360	NA
60.072	405	NA
60.063	463	NA
60.054	540	NA
60.045	648	NA
60.036	810	NA
60.027	1080	NA
60.018	1620	NA
59.982	NA	-1080
59.973	NA	-720
59.964	NA	-540
59.955	NA	-432

Table 3.2: Varying Frequency Results		
Actual Frequency	**$BAAL_{High}$**	**$BAAL_{Low}$**
59.946	NA	-360
59.937	NA	-309
59.928	NA	-270
59.919	NA	-240
59.91	NA	-216

The BAAL limits plotted in **Figure 3.4** detail the acceptable operating area and the BAAL limit exceedance area.

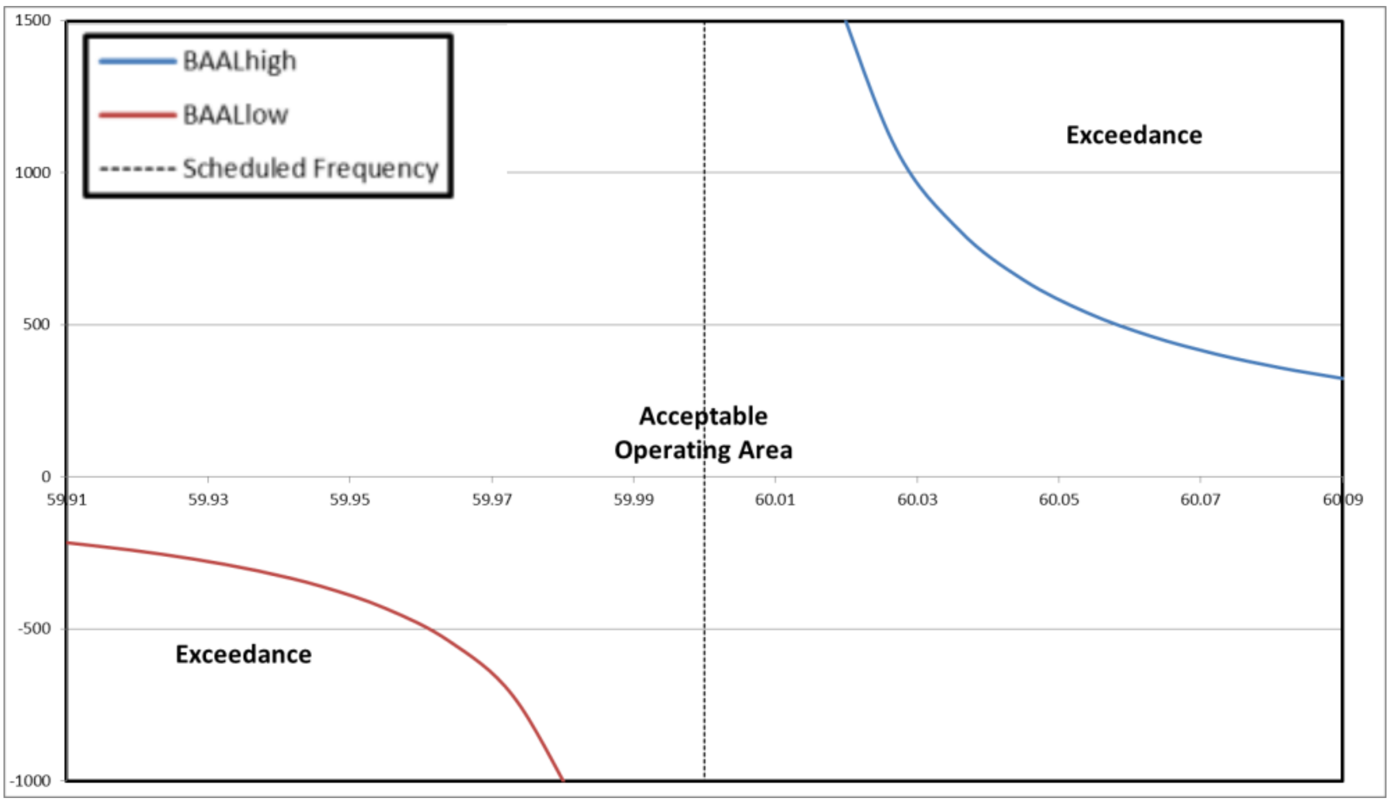


Figure 3.4: Acceptable Operating Area and the BAAL limit exceedance area

As a BA is operating and managing its ACE, the clock-minute averages of ACE are being evaluated against the BAAL limits.

CPS1 Equivalent Limit Derivation

BAAL is mathematically related to CPS1 as shown below:

- By definition; $CF = (RACE/(-10B) * (F_A - F_S)) / (\varepsilon_1{}^2)$, and $CPS1 = 2 - CF$
- Substituting for CF; $CPS1 = 2 - (RACE/(-10B) * (F_A - F_S)) / (\varepsilon_1{}^2))$
- Regrouping terms; $CPS1 = 2 - RACE * ((F_A - F_S) / (-10B * \varepsilon_1{}^2))$

- Substituting BAAL for RACE; CPS1 = 2 - 9 * (-10B* ε_1^2) / (F_A - F_S) * ((F_A - F_S)/(-10B* ε_1^2))
- Cancelling out terms; CPS1 = 2 – 9= -7 = -700%

Therefore, a one-minute CPS1 score more negative than -700% will equate to a BAAL exceedance for that one-minute period.

The minimum acceptable time frame for continuous BAAL minute exceedances shall not continue for greater than thirty minutes.

Quick Review

- CPS1 assigns each BA a share of the responsibility for control of Interconnection frequency.
- CPS1 is a yearly (i.e., rolling twelve month) standard that measures impact on frequency error with a 100% minimum allowable score.
- BAAL is a 30-minute standard intended to bind a BAs real-time impact on frequency.

Chapter 4: Tertiary Control

Tertiary Control generally follows disturbances and reserve deployment to reestablish resources for future contingencies. Reserve deployment and reserve restoration following a disturbance are common types of Tertiary Control. See the Operating Reserve Management Reliability Guideline for more information.

Understanding Reserves

There is often confusion when operators and planners talk about reserves. One major reason for misunderstanding is a lack of common definitions; NERC's definitions have changed over time. In addition, most NERC Regions developed their own definitions. Capacity obligations have historically been the purview of state and provincial regulatory bodies, meaning that there are many different expectations and obligations across North America.

In order to foster discussion and develop a more uniform understanding of the reserve data, the following definitions are provided in this reference. Refer to **Figure 4.1** to better understand the definitions.

Definitions:

(Capitalized terms are taken from NERC Glossary and lower case are not.)

Contingency Reserve: The provision of capacity deployed by the BA to respond to a Balancing Contingency Event and other contingency requirements (such as Energy Emergency Alerts as specified in the associated NERC Standards). This is the left column of Operating Reserves in Figure 4.1

Frequency-responsive reserve: On-line generation with headroom that has been tested and verified to be capable of providing droop as described in the Primary Frequency Response guideline. Variable load that mirrors governor droop and dead-band may also be considered frequency responsive reserve.

Interruptible Load: Demand that the end-use customer makes available to its Load-Serving Entity via contract or agreement for curtailment that can be interrupted within 10 minutes.

Operating Reserve: That capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages, and local area protection.

Operating Reserve–Spinning: Generation synchronized to the system and fully available to serve load within the Disturbance Recovery Period following the contingency event or Load fully removable from the system within the Disturbance Recovery Period following the contingency event deployable in 10 minutes.

Operating Reserve Supplemental: Generation (synchronized or capable of being synchronized to the system) that is fully available to serve load within the Disturbance Recovery Period following the contingency event or Load fully removable from the system within the Disturbance Recovery Period following the contingency event that can be removed from the system, within 10 minutes.

Planning reserve: The difference between a BA's expected annual peak capability and its expected annual peak demand expressed as a percentage of the annual peak demand. See BAL-502-RF-03 for additional discussion.

Regulating Reserve: An amount of Operating Reserve – Spinning responsive to Automatic Generation Control, which is sufficient to provide normal regulating margin.

Replacement reserve: NOTE: Each NERC Region sets times for reserve restoration, typically in the 60–90-minute range. The NERC default contingency reserve restoration period is 90 minutes after the disturbance recovery period.

Supplemental Reserve Service: Provides additional capacity from electricity generators that can be used to respond to a contingency within a short period, usually ten minutes. An ancillary service identified in FERC Order 888 as necessary to affect a transfer of electricity between purchasing and selling entities. This is effectively FERC's equivalent to NERC's Operating Reserve.

Much like parts kept in a storeroom, reserves are meant to be used when the need arises. Reserves can be low for short periods of time due to plant equipment problems and unit trips and can also be misstated

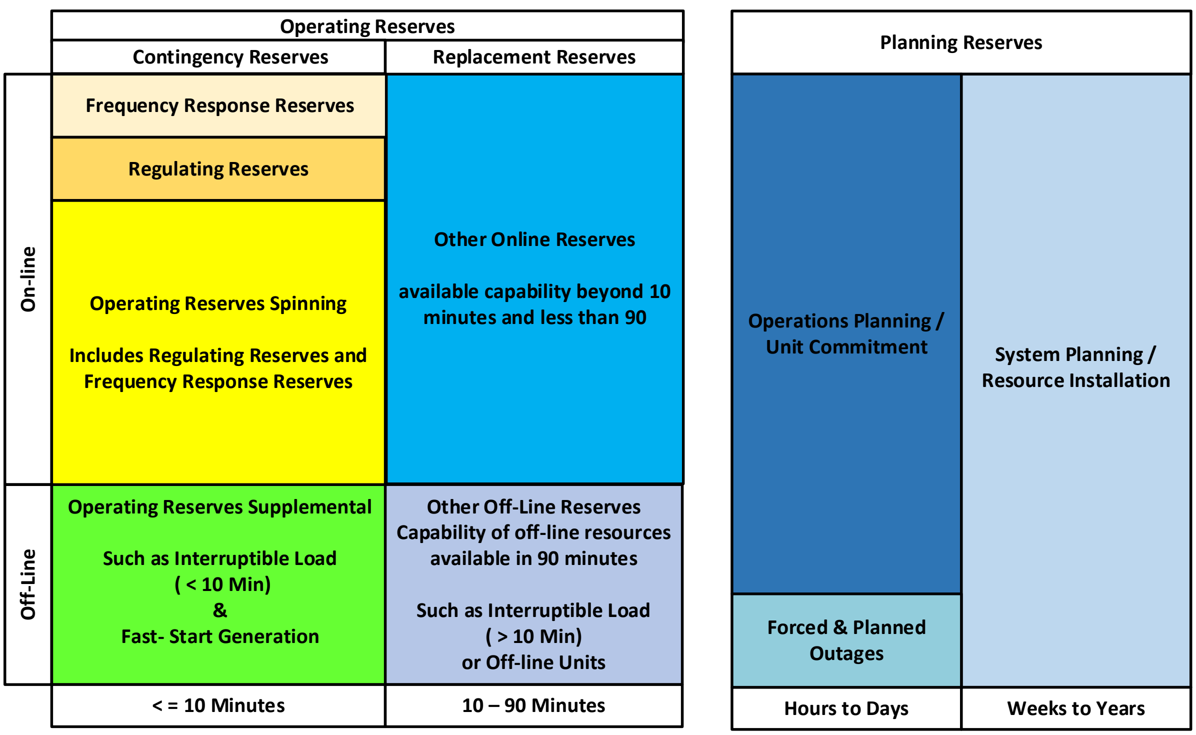


Figure 4.1: Reserves Continuum

Chapter 5: Time Control and Inadvertent Interchange

Background

There is a strong interrelationship between control of time error and Inadvertent Interchange (aka. "inadvertent"). Time error occurs when one or more BAs has imprecise control or large resource losses occur, causing average actual frequency to deviate from scheduled frequency. The bias term in the ACE equation of the remaining BAs causes control actions that result in flows between BAAs in the opposite direction. The net accumulation of all these interchange errors is referred to as Inadvertent Interchange. Inadvertent interchange represents the amount by which actual flows between BAAs and the remainder of the Interconnection differs from the intended or scheduled flows.

Time Control

As noted earlier, frequency control and balancing control are not perfect. There will always be some errors in tie-line meters. Due to load and generation variation, net ACE in an Interconnection cannot be maintained at zero. This means that frequency will vary from 60 Hz over time.

An Interconnection may have a time control process to maintain the long-term average frequency at 60 Hz. While there are some differences in process, each Interconnection that exercises time control designates an RC as a "time monitor" to coordinate time control.

Time error corrections are initiated when long-term average frequency drifts from 60 Hz. In the EI, a 0.02Hz offset to scheduled frequency corrects 1.2 seconds on the clock for each hour of the time error correction, provided the offset scheduled frequency is achieved.

There has been an ongoing debate on the need for time error corrections. The number of time error corrections do provide a benchmark for the quality of frequency control and provide an early warning of chronic balancing problems. While the value of time control is debatable from a reliability perspective, nobody can say with assurance who or what would be impacted if NERC and NAESB halted the practice of manual time error corrections. This practice was removed from the NERC standards in 2017, but still remains in the NAESB standards.

Inadvertent Interchange

Inadvertent interchange is net imbalance of energy between a BA and the Interconnection. The formula for inadvertent interchange is:

- $NI_I = NI_A - NI_S$

where,

NI_A is net actual interchange. It is the algebraic sum of the hourly integrated energy on a BAs tie lines. Net actual interchange is positive for power leaving the system and negative for power entering.

NI_S is net scheduled interchange. It is defined as the mutually prearranged net energy to be delivered or received on a BAs tie lines. Net scheduled interchange is positive for power scheduled to be delivered from the system and negative for power scheduled to be received into the system.

Inadvertent interchange and can be divided into two categories, described below.

Primary Inadvertent

Primary inadvertent interchange is caused by problems or action from within a given BA. Primary inadvertent interchange occurs due to the following:

- Error in scheduled interchange
  - Improper entry of data (time, amount, direction, duration, etc.…)
  - Improper update in real-time (TLR miscommunication etc.…)
  - Ramp procedures
  - Miscellaneous (phantom schedules, selling off the ties, etc.…)
- Error in actual interchange (meter error)
  - Loss of telemetry
  - Differences between real-time power (MW, for ACE), and energy (MWh), integrated values
- Control error or offset
  - Load volatility and unpredictability
  - Generation outages
  - Generation uninstructed deviations
  - Physical rate-of-change-of-production limitations
  - Deliberate control offset (i.e. unilateral payback) to reduce inadvertent energy balances

Hourly primary inadvertent can be calculated for each BA by using the following formula:

$(PII_{hourly}) = (1\text{-}Y) * (II_{actual} - Bi * \Delta TE/6)$

- PII_{hourly} is the BAs primary inadvertent for an operating hour expressed in MWh
- Y is the ratio between a BAs frequency bias setting and the sum of all BAs frequency bias setting within an Interconnection
- Bi is the BAs frequency bias
- ΔTE is the change in time error within the Interconnection that occurred during the operating hour

Secondary Inadvertent

Balancing problems external to a BA will cause off-schedule frequency. If frequency is low, the bias term of the ACE equation will cause a BA to slightly over-generate after initial effects to stabilize frequency, such as governor response and load damping. Conversely, if frequency is high, the bias term of the ACE equation will cause slight under generation. This intentional outflow or inflow to stabilize frequency due to problems outside the BA causes deviation from the schedule and is called secondary inadvertent interchange.

Hourly secondary inadvertent can be derived by subtracting a BA's hourly primary inadvertent from their hourly total inadvertent.

Quick Review: If one or more BAs have a control problem, it could result in a large primary inadvertent interchange. This may also cause off-nominal frequency, potentially spreading Secondary inadvertent interchange to the other BAs. The off-normal frequency then results in accumulated time error, potentially triggering time error corrections.

Chapter 6: Frequency Correction and Intervention

Background

There are several requirements in NERC reliability standards that tell the BA, Transmission Operator, and RC to monitor and control frequency. The standards do not provide specific guidance on what is normal frequency and under what conditions the operator should intervene.

As noted earlier in this document, this information is provided for guidance and understanding. It should not be used for compliance purposes and does not establish new requirements or obligations.

The BAAL is the ACE-frequency combination equivalent to instantaneous CPS1 of -700%. In general, if one or more of the RC's BAs is beyond the BAAL for more than 15 minutes, the RC should contact the BA to determine the underlying cause. As frequency diverges more from 60 Hz, the RC and BA should be more aggressive in their actions.

One of the primary responsibilities of the RCs is frequency protection. Suggested actions are outlined below.

1. Identify BAs within your area beyond BAAL. Direct correction and log. RCs to notify BAs.
2. Call Other RCs, communicate problem if known. Search for cause if none reported. Notify time monitor of findings. Time monitor to log. Direct BAs beyond BAAL to correct ACE.
3. Direct all BAs with ACE hurting frequency to correct. Time monitor to notify Resource Subcommittee after the fact.
4. Evaluate whether still interconnected. Direct emergency action.

Revision History

Date	Version Number	Reason/Comments
4-5-2011	1.0	Initial Version
5-11-2021	2.0	Resources Subcommittee Review

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