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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

BALANCING AND FREQUENCY CONTROL

A Technical Document Prepared by the NERC Resources Subcommittee

to ensure the reliability of the bulk power system

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Introduction

Background
The NERC Resources Subcommittee drafted this reference 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 NERC Resources Subcommittee will post supporting information at: http://www.nerc.com/~filez/rs_tutorials.html.

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

Balancing Fundamentals

Balancing and Frequency Control Basics

The power system of North America is divided into four major Interconnections. These Interconnections can be thought of as (frequency-) independent islands. The Interconnections are:

- Western – Generally everything west of the Rockies.
- Texas – Also known as Electric Reliability Council of Texas (ERCOT).
- Eastern – Generally everything east of the Rockies except Texas and Quebec.
- Quebec

Each Interconnection is actually a large machine, as every generator within the island is pulling in tandem with the others to supply electricity to all customers. This occurs as the rotation of electric generating units, nearly all in (steady-state) synchronism. The "speed" (of rotation) of the Interconnection is frequency, measured in cycles per second or Hertz (Hz). If the total Interconnection generation exceeds customer demand, frequency increases beyond the target value, typically 60 Hz[1], until energy balance is achieved. Conversely, if there is a temporary generation deficiency, frequency declines until balance is again restored at a point below the scheduled frequency. Balance is initially restored in each case due to load that varies with frequency and generator governors that change generator output in response to frequency changes. Some electric devices, such as electric motors, use more energy if driven at a higher frequency and less at a lower frequency.

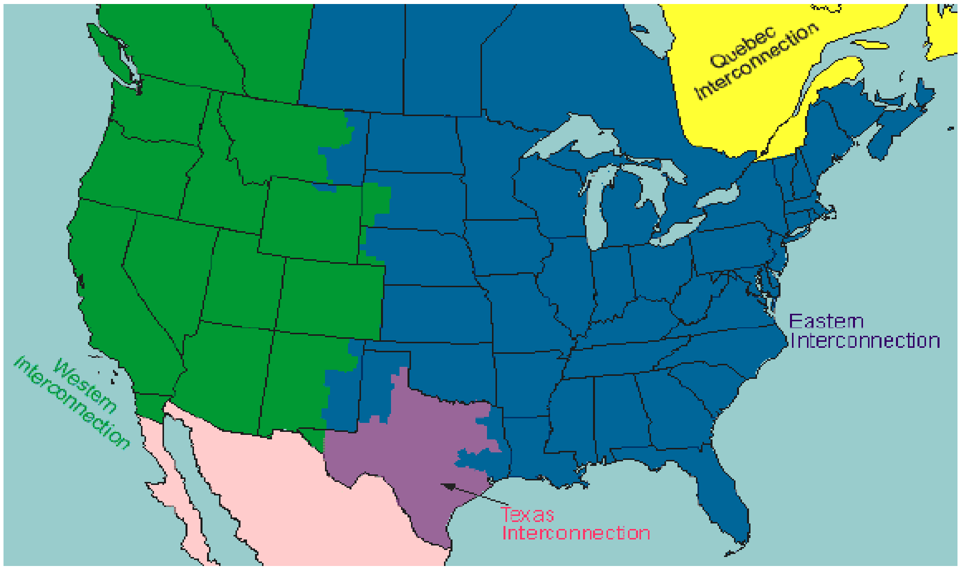


Figure 1 — North American Interconnections

1 Target frequency (termed Scheduled Frequency) is sometimes offset by a small amount via a mechanism called Time Error Corrections. In the Easternn Interconnection this is presently +/- 0.02Hz

Balancing of generation and load within the Interconnections is handled by entities called Balancing Authorities. The Balancing Authorities dispatch generators in order to meet their individual needs. Some Balancing Authorities also control load to maintain the load – generation balance.

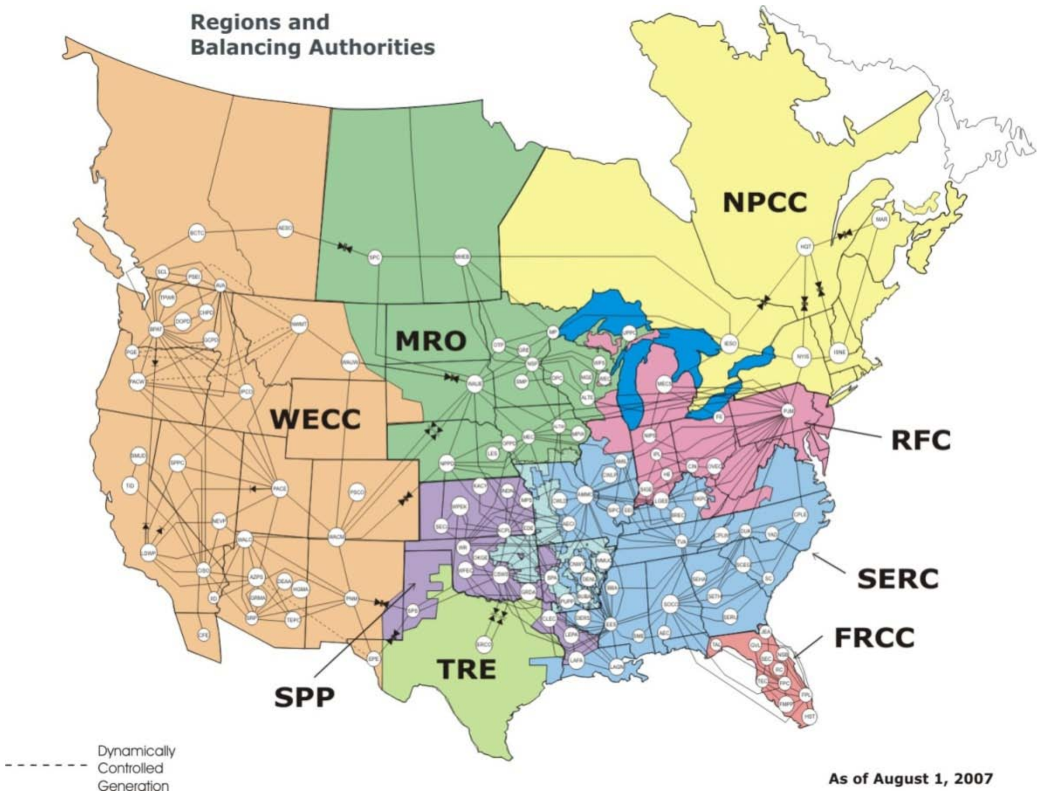


Figure 2 —North American Balancing Authorities and Regions

There are over 100 Balancing Authorities of varying size in North America. Each Balancing Authority in an Interconnection is connected via high voltage transmission lines (called tie-lines) to neighboring Balancing Authorities. Overseeing the Balancing Authorities are wide-area operators called Reliability Coordinators. The relationship between Reliability Coordinators and Balancing Authorities is similar to that between air traffic controllers and pilots.

Frequency does not change in an Interconnection as long as there is a balance between resources and customer demand (including various electrical losses). This balance is depicted in Figure 3a.

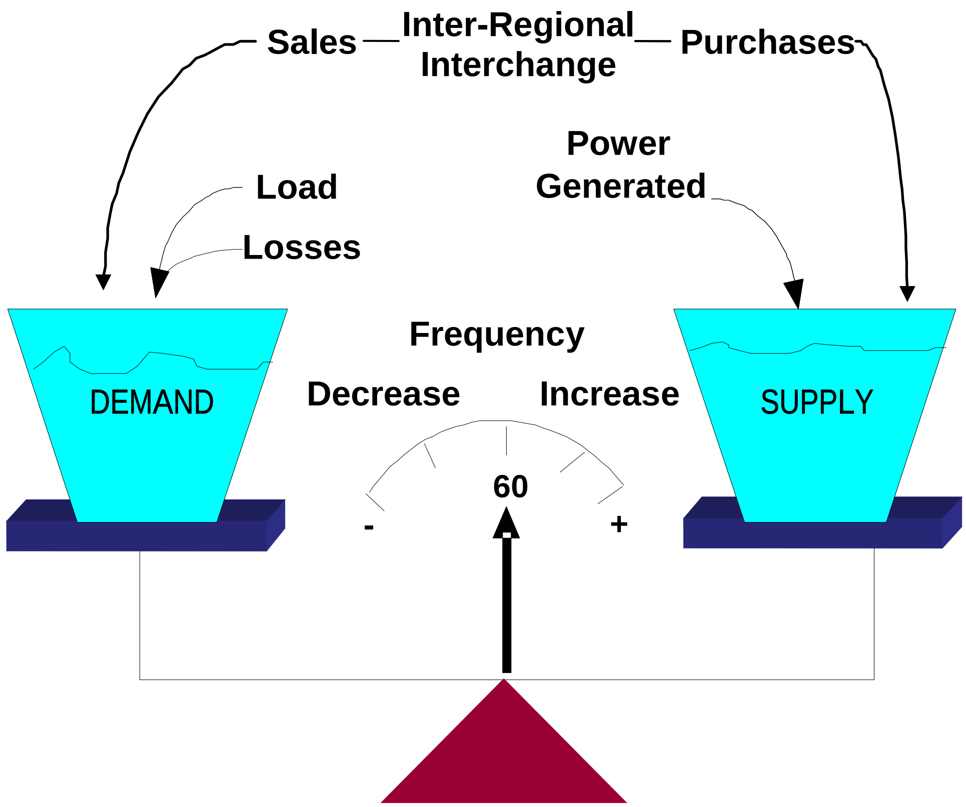


Figure 3a — Generation / Demand Balance

Each generator embedded in an interconnected system has its own characteristics, which can be analogized to a pump with storage and control, as shown in Figure 3b. Here, the pump's output fills a storage tank (similar to a steam drum in a thermal-steam unit). The control valve acts like an AGC input, changing average output to meet system demand. The surge tank on the final output is analogous to the rotational inertia of the generator.

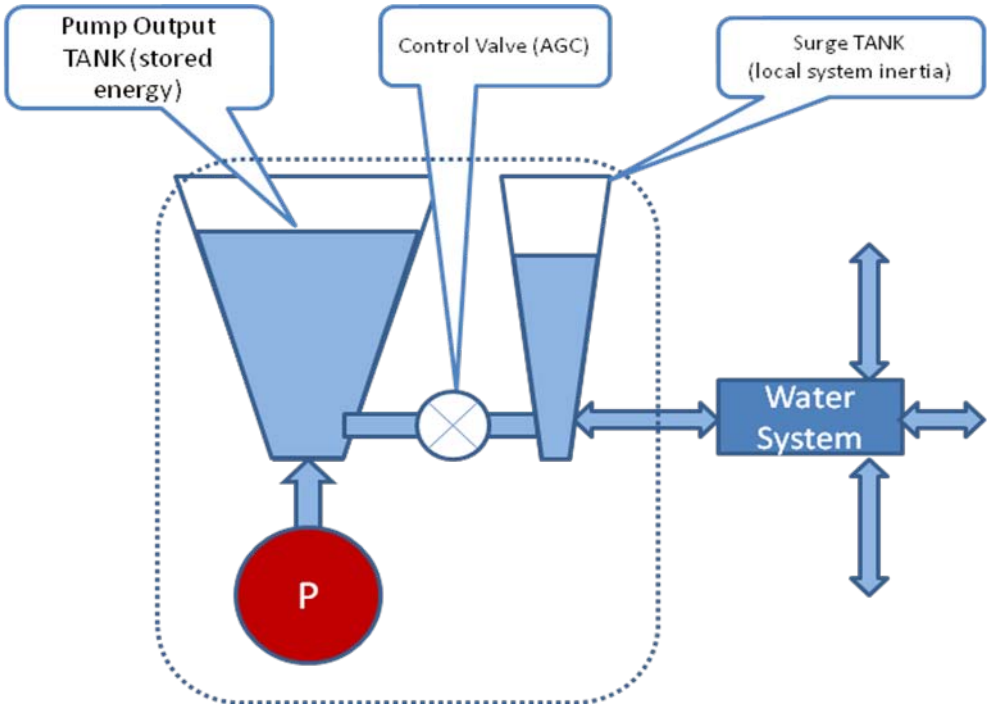


Figure 3b — Generator / Pump Analogy

To understand how Interconnection frequency is actually controlled, it may help to visualize a traditional water utility, composed of a delivery system, customers, and several pumps as depicted above. If a municipality operated its own system, it would need sufficient pumps (generation) to maintain level in a storage tank (frequency) to serve its customers. If demand exceeded supply, the level would drop. Level (frequency) is the primary parameter to control in an independent system.

Utilities quickly learned the benefits in reliability and reduced operating reserves expense by connecting to neighboring systems. In our water utility example, an independent utility must have pumps in standby equivalent to its largest online pump if it wants to maintain level. However, if utilities are connected together via pipelines (tie-lines), reliability and economics are improved, both because of the larger storage capability of the combined system and the ability to share pump capacity when needed.

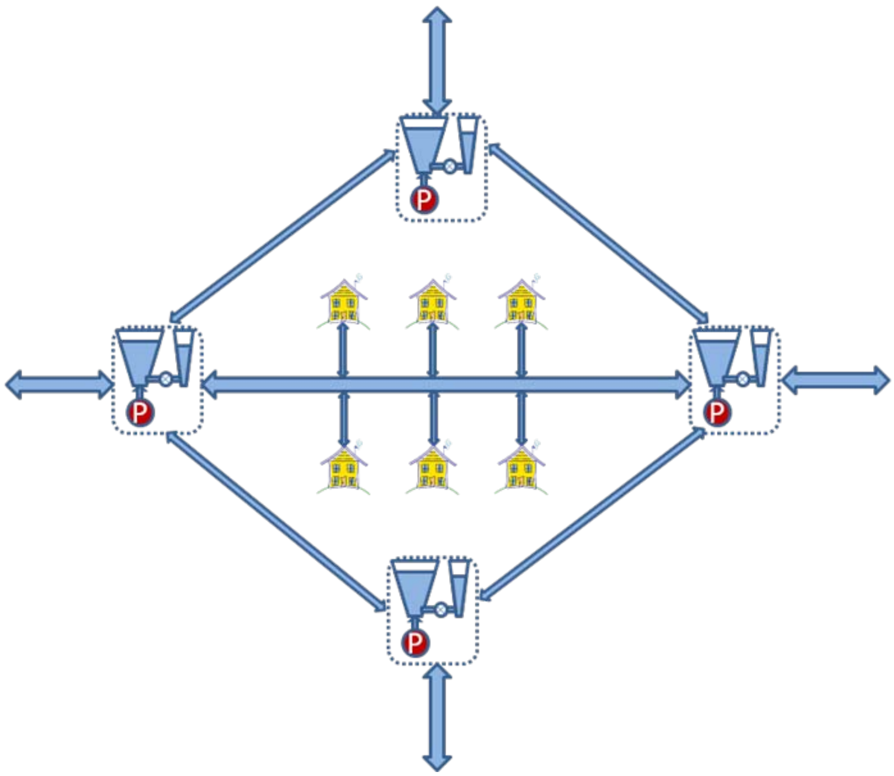


Figure 3 — Balancing Authority Analogy

Once the systems are interconnected, the level (steady state frequency) is the same throughout. If one utility (Balancing Authority) loses a pump, there is a drop in level, although it is now much less than in an independent system. The Balancing Authority that needed water (energy) could purchase output from others.

Thus, there are two inputs to the Balancing Authorities' control process[2]:

- Interchange Error, which is the net outflow or inflow compared to what it is scheduled to be buying or selling.
- Frequency Bias, which is the Balancing Authority's obligation to provide or absorb energy to assist in stabilizing frequency. In other words, if frequency goes low, each Balancing Authority is asked to contribute a small amount of extra generation in proportion to its system's established bias.

Each Balancing Authority uses common meters on the tie-lines with its neighbors for control and accounting. In other words, there will be a meter on one end of each tie-line that both neighboring Balancing Authorities use against which they control and perform accounting. Thus, all generators, load, and transmission lines in an Interconnection fall within the metered bounds of a Balancing Authority.

2 There are two control inputs in multi-Balancing Authority Interconnections. Texas and Quebec are single Balancing Authority Interconnections and need only control to frequency.

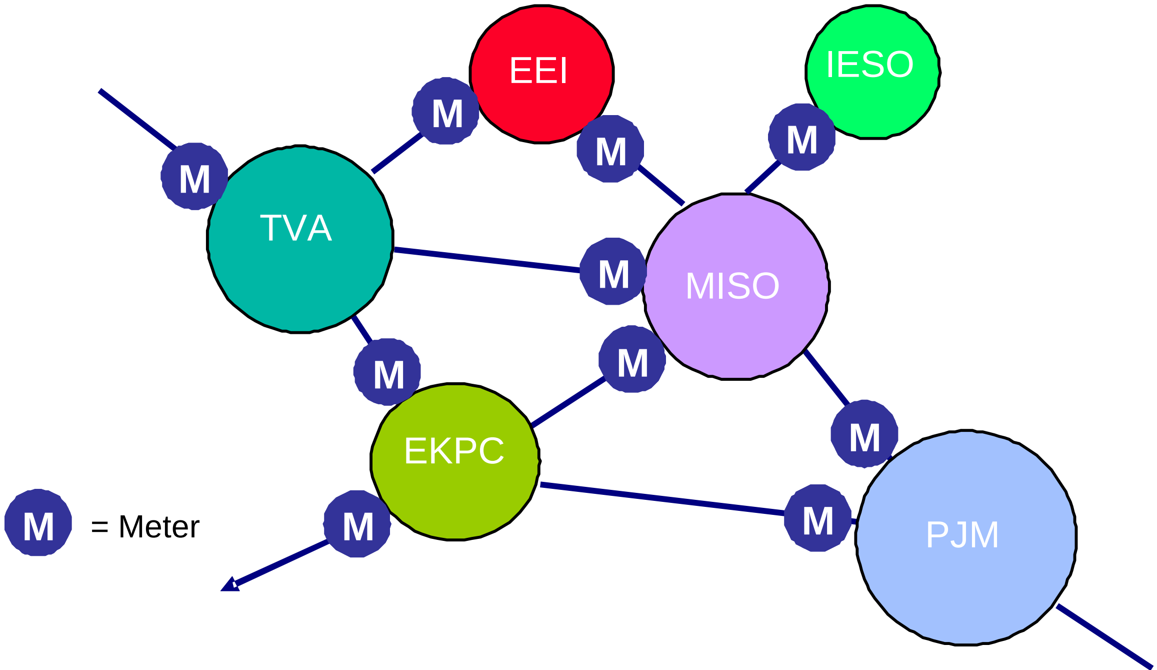


Figure 4 — Interconnected Balancing Authorities

If the Balancing Authority is not buying or selling energy[3], and its generation is exactly equal to the load and losses within its metered boundary, and interconnection frequency is exactly on schedule then the net of its tie line meters will be zero. If the Balancing Authority chooses to buy energy, say 100 Megawatts (MW), it tells its control system to allow 100 MW to flow in. Conversely, the seller will tell its control system to allow 100 MW to flow out. If all Balancing Authorities behave this way, the Interconnection remains in balance and frequency remains stable. If an error in control (and a resulting imbalance) occurs, it will show up as a change in frequency.

Customer demand and generation are constantly changing within all Balancing Authorities. This means Balancing Authorities will usually have some unintentional outflow or inflow at any given instant. This mismatch in meeting a Balancing Authority'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), estimated in MW.

Dispatchers at each Balancing Authority fulfill their NERC obligations by monitoring ACE and keeping the value within limits that are generally proportional to Balancing Authority size. This balancing typically is accomplished through a combination of computer-controlled adjustment of generators, telephone calls to power plants and

3 In most cases, Balancing Authorities do not buy and sell energy. Transactions now are arranged by agents called Purchasing-Selling Entities (PSEs) that represent load or generation within the Balancing Authority.

through purchases and sales of electricity with other Balancing Authorities, and possible emergency actions such as automatic or manual load shedding.

Conceptually, ACE is to a Balancing Authority what frequency is to the Interconnection. Over-generation makes ACE go positive and puts upward pressure on Interconnection frequency. A large negative ACE causes Interconnection frequency to drop. Highly variable, or “noisy”, ACE tends to contribute to similarly “noisy” frequency. However, the effect of ACE on frequency depends on whether ACE is coincident with frequency error. Frequency error tends to be made larger when ACE is of the same sign as the error, and is made smaller when ACE is of opposite sign to the frequency error. This principle is captured in the way CPS1 measures performance.

Failure to maintain a balance between load and resources causes frequency to vary from its target value. Other problems on the grid, such as congestion or equipment faults which dictate rapid unilateral adjustments of generation or loss of load cause changes in frequency. Frequency can therefore be thought of as the pulse of the grid and a fundamental indicator of the health of the power system.

Control Continuum

Balancing and frequency control occur over a continuum of time using different resources, represented in
Figure 5.

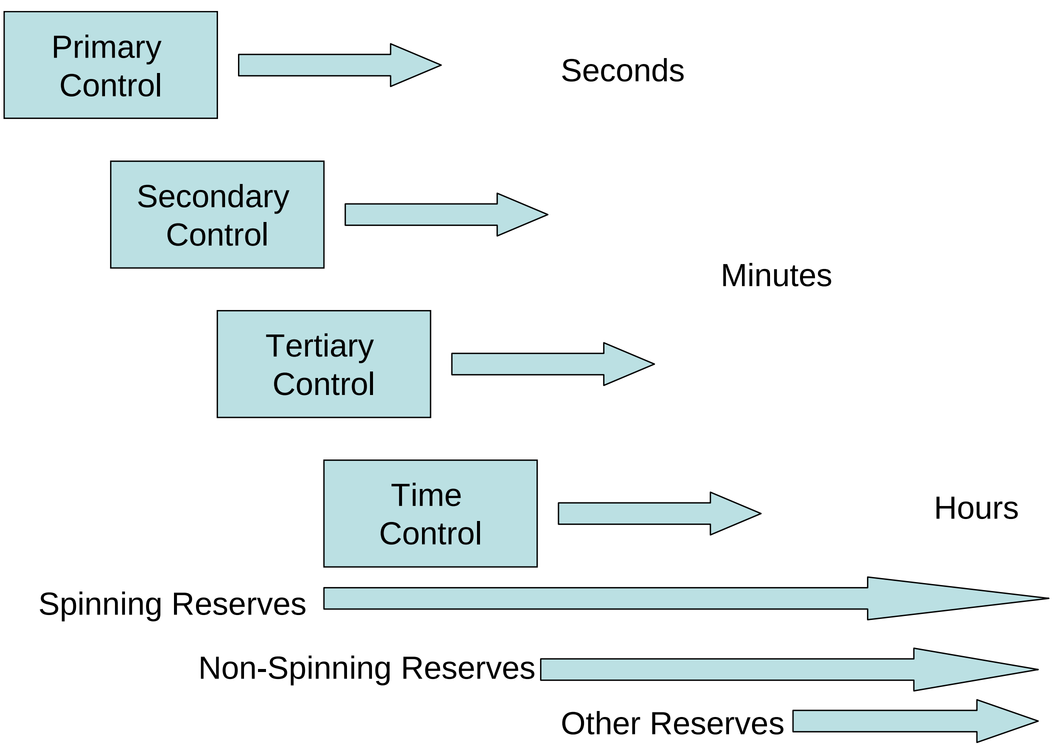


Figure 5 — Control Continuum

Primary Control

Primary Control is more commonly known as Frequency Response. Frequency Response occurs within the first few seconds following a change in system frequency (disturbance) to stabilize the Interconnection. Frequency Response is provided by:

1. Governor Action. Governors on generators are similar to cruise control on your car. They sense a change in speed and adjust the energy input into the generators' prime mover.
2. Load. The speed of motors in an Interconnection change in direct proportion to frequency. As frequency drops, motors will turn slower and draw less energy. Rapid reduction of system load may also be effected by automatic operation of under-frequency relays which interrupt pre-defined 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.

   These load characteristics assist in stabilizing frequency following a disturbance.

The most common type of disturbance in an Interconnection is associated with the loss of a generator, which causes a decline in frequency. In general, the amount of (frequency-responsive) Spinning Reserve in an Interconnection will determine the amount of available Frequency Response.

It is important to remember that Primary Control will not return frequency to normal, but only stabilize it. Other control components are used to restore frequency to normal.

> **Operating Tip:** Frequency Response is particularly important during disturbances and islanding situations. Operators should be aware of their frequency responsive resources. Blackstart units must be able to control to frequency and arrest excursions.

Secondary Control

Secondary Control typically includes the balancing services deployed in the "minutes" time frame. Some resources however, such as hydroelectric generation, can respond faster in many cases. This control is accomplished using the Balancing Authority's control computer[4] and the manual actions taken by the dispatcher to provide additional adjustments. Secondary Control also includes initial reserve deployment for disturbances.

In short, Secondary Control maintains the minute-to-minute balance throughout the day and is used to restore frequency to its scheduled value, usually 60 Hz, following a

4 Terms most often associated with this are "Load-Frequency Control" or "Automatic Generation Control".

disturbance. Secondary Control is provided by both Spinning and Non-Spinning Reserves.

The most common means of exercising secondary control is through Automatic Generation Control (AGC). AGC operates in conjunction with Supervisory Control and Data Acquisition (SCADA) systems. SCADA gathers information about an electric system, in particular system frequency, generator outputs, and actual interchange between the system and adjacent systems. Using system frequency and net actual interchange, plus knowledge of net scheduled interchange, it is possible to determine the system's energy balance with its interconnection in near-real-time. Most SCADA systems poll sequentially for electric system data, with a typical periodicity of four 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 Balancing Area's Area Control Error (ACE, further described below) from interchange and frequency data. ACE tells whether a system is in balance or needs to make adjustments to generation. AGC software, while observing ACE, automatically determines the most economical output for generating resources while observing energy balance and frequency control, usually by sending setpoints to generators. Some generators also use pulse-accumulator methodology to derive a setpoint from pulses sent by AGC, but these have become less common over time.

The degree of success of AGC in complying with balancing and frequency control is manifested in a Balancing Area's control performance compliance statistics, which 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 transducer inaccuracy, problems with SCADA hardware or software, or communications errors. Due to these errors, plus normal load and generation variation, net ACE in an Interconnection cannot be maintained at zero. This means that frequency cannot always be maintained at exactly 60Hz, and that average frequency over time usually is not exactly 60 Hz.

Each Interconnection has a Time Control process to maintain the long-term average frequency at 60 Hz. While there are some differences in process, each Interconnection designates a Reliability Coordinator as a "Time Monitor" to provide Time Control.

The Time Monitor compares a clock driven off Interconnection frequency against "official time" provided by the National Institute of Standards and Technology (NIST). If average frequency drifts, it creates a Time Error between these two clocks. In the

Western Interconnection, time-error-correction is done automatically through software maintained by the Time Monitor known as Automatic Time Error Correction. In the other interconnections, if the Time Error gets too large, the Time Monitor will notify Balancing Authorities in the Interconnection to correct the situation.

For example, if frequency has been running 2 mHz high (60.002Hz), a clock using Interconnection frequency as a reference will gain 1.2 seconds in a 10 hour interval (i.e., 60.002 Hz-60.000 Hz)/60 Hz * 10 hrs * 3600 s/hr = 1.2 s). If the Time Error accumulates to a pre-determined value (for this example, +10 seconds in the Eastern Interconnection), the Time Monitor will send notices for all Balancing Authorities in the Interconnection to offset their scheduled frequency by -0.02Hz (Scheduled Frequency = 59.98Hz). This offset, known as Time Error Correction, will be maintained until Time Error has decreased below the termination threshold (which would be +6 seconds for our example in the eastern interconnection).

A positive offset (Scheduled Frequency = 60.02Hz) would be used if average frequency was low and Time Error reached its initiation value (-10 seconds for the Eastern Interconnection). See the NAESB business practice on Manual Time Error Correction for additional information.

Control Continuum

Summary Table 1 summarizes the discussion on the control continuum and identifies the service[5] that provides the control and the NERC standard that addresses the adequacy of the service.

Control	Ancillary Service/IOS	Timeframe	NERC Standard
Primary Control	Frequency Response	10-60 Seconds	FRS-CPS1
Secondary Control	Regulation	1-10 Minutes	CPS1– CPS2 – DCS - BAAL
Tertiary Control	Imbalance/Reserves	10 Minutes - Hours	BAAL - DCS
Time Control	Time Error Correction	Hours	TEC

Table 1 — Control Continuum Summary

Current issues, good practices, and recommendations on balancing and frequency control are discussed later.

5 NERC calls these services "Interconnected Operations Services" while the FERC uses the term Ancillary Services.

Area Control Error (ACE) Review

The Control Performance Standards are based on measures that limit the magnitude and direction of the Balancing Authority's Area Control Error (ACE). The equation for ACE is:

$$ACE = (NI_A - NI_S) - 10B\,(F_A - F_S) - I_{ME}$$

Where:

NI_A is Net Interchange, Actual
NI_S is Net Interchange, Scheduled
B is Balancing Authority Bias
F_A is Frequency, Actual
F_S is Frequency, Scheduled
I_{ME} is Interchange (tie line) Metering Error

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

The combination of the two (NI_A - NI_S) represents the ACE associated with meeting schedules, without consideration for frequency error or bias, and if used by itself for control would be referred to as "flat tie line" control.

The term 10B (F_A - F_S) is the Balancing Authority's obligation to support frequency. B is the Balancing Authority's frequency bias stated in MW/0.1Hz (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[6] flow are not always as accurate as the hourly meters on tie lines. Balancing Authorities 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.

Here is a simple example. Assume a Balancing Authority with a Bias of -50 MW / 0.1 Hz is purchasing 300 MW. The actual flow into the Balancing Authority is 310 MW. Frequency is 60.01 Hz. Assume no time correction or metering error.

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

6 Instantaneous, as used herein, refers to measurements which are as close to real-time, or instantaneous, as are possible within the limits of data acquistion and conversion equipment.

The Balancing Authority 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 Balancing Area 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 control performance standard (CPS) compliance.

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 Glossary7, is the mathematical expression of the net change in a Balancing Area's Net Actual Interchange for a change in interconnection frequency. It is a fundamental reliability service provided by a combination of governor and load response. Frequency Response represents the actual MW primary response contribution to stabilize frequency following a disturbance.

Bias is an approximation of β used in the ACE equation. Bias prevents AGC withdrawal of frequency support following a disturbance. If B and β were exactly equal, a Balancing Authority 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 negative numbers. In other words, as frequency drops, MW output (β) or desired output (B) increases. Both are measured in MW/0.1Hz

> **Important Note:** When people talk about Frequency Response and Bias, they often discuss them as positive values (such 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 (absolute value of B greater than the absolute value of β) than to be under-biased.

7 Select from list found at: http://www.nerc.com/commondocs.php?cd=2

Detailed Discussion

Primary Control (Frequency Response)

Background
Primary Control relates to the supply and load responses, including generator governors (speed controls) that 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. Frequency Response (or Beta) is the more common term for Primary Control. Beta (β) is defined by the total of all initial responses to a frequency excursion.

Figure 6 shows a trace of the Western Interconnection's frequency resulting 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. Point A is the pre-disturbance frequency, typically close to 60 Hz. Point C is the maximum excursion point, which in this WECC example occurs about 5–8 seconds after the loss of generation. Point B is the settling frequency of the Interconnection.

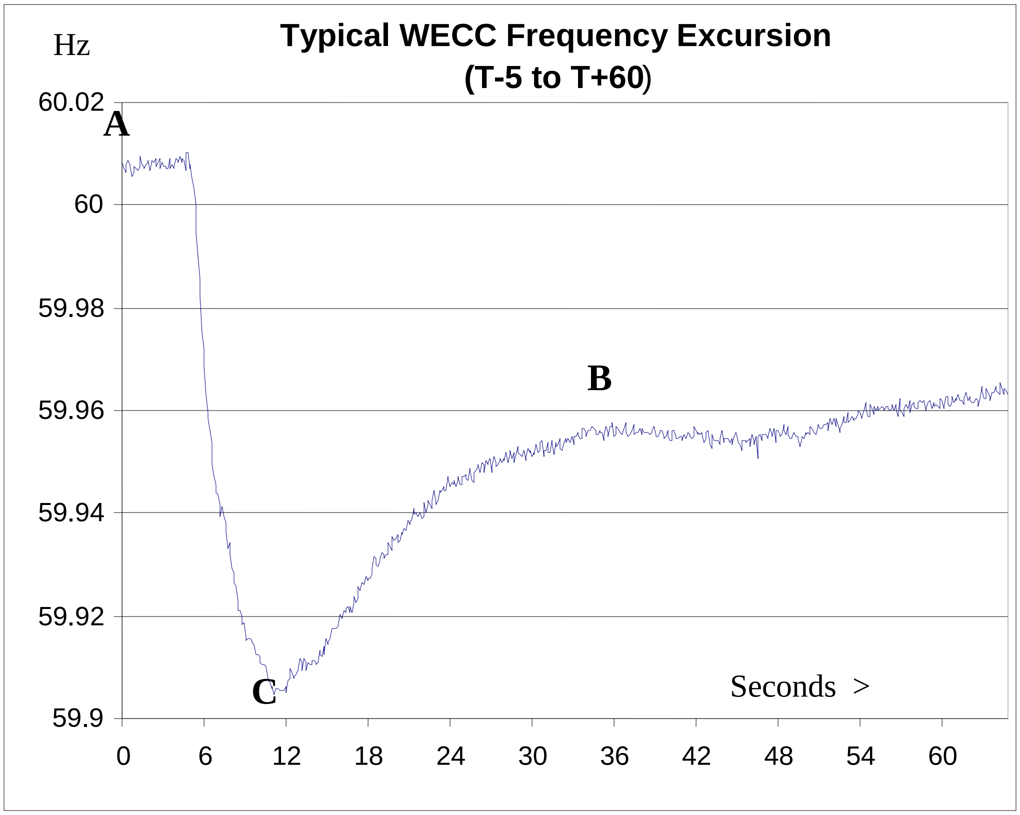


Figure 6 — WECC Frequency Excursion

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.

Generator Governors (Speed Controls)
The most fundamental, front-line control of frequency in AC electric systems is the action of generator governors. Because of the sensitivity of generators and loads to frequency, and to prevent frequency instability and possible collapse, it is important to maintain stability of the interconnection operating frequency and responses to changes in it. Governors operate in the timeframe 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.

Slope – Governors act to cause generators to try and maintain a constant, stable system frequency (60 Hertz in North America). They do this by constantly regulating (modulating) the amount of mechanical input energy to the shaft of the electric generator. The degree of this modulation is called "slope", 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%, which means that if frequency error is 5% (or 3 Hz) the full output of the generator would be used (or attempt to be used) to counteract the frequency error. 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 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 simply means that until frequency error is beyond a threshold, the governor ignores it. When frequency error exceeds the threshold (.036 Hz, or 36 mHz by convention) the governor becomes active. It is worth noting that for older, mechanical-style governors the deadband may be larger and has associated with it the mechanical lash that exists in mechanically-coupled devices.

Without governor action, loss of generation would result in frequency that would not stabilize until the interconnection load – frequency characteristic resulted in a (reduced) load that matched the remaining generation output. This point could be 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 governor response and load – frequency response - is the “beta” (β), or frequency response characteristic, of a Balancing Area. This is the characteristic which AGC attempts to mimic in its use of the frequency bias (“B”) parameter in determining ACE. The net of all Balancing Area frequency responses manifests as the interconnection frequency response, discussed in Frequency Response Trends.

Frequency Response Trends

Studies over the past 30 years have shown a general decline in Frequency Response in the Eastern Interconnection, and mixed results in other interconnections. In theory it should be increasing with increasing load and generation. Since 1994, Eastern Interconnection Beta has declined roughly 20 percent even though it should have been increasing in proportion to a 20 percent increase in customer demand. Figure 7 shows the recent trend in Beta.

While this trend is of concern, some caution is needed. Early studies were based on limited samples of generally large events. Such events would generally trigger more Primary Control.

The underlying reason for the proposed Frequency Response Standard is to develop an objective method to calculate Beta for all Balancing Authorities and Interconnections. For example, it is unknown whether the general trend is global or whether there are specific areas with low Frequency Response.

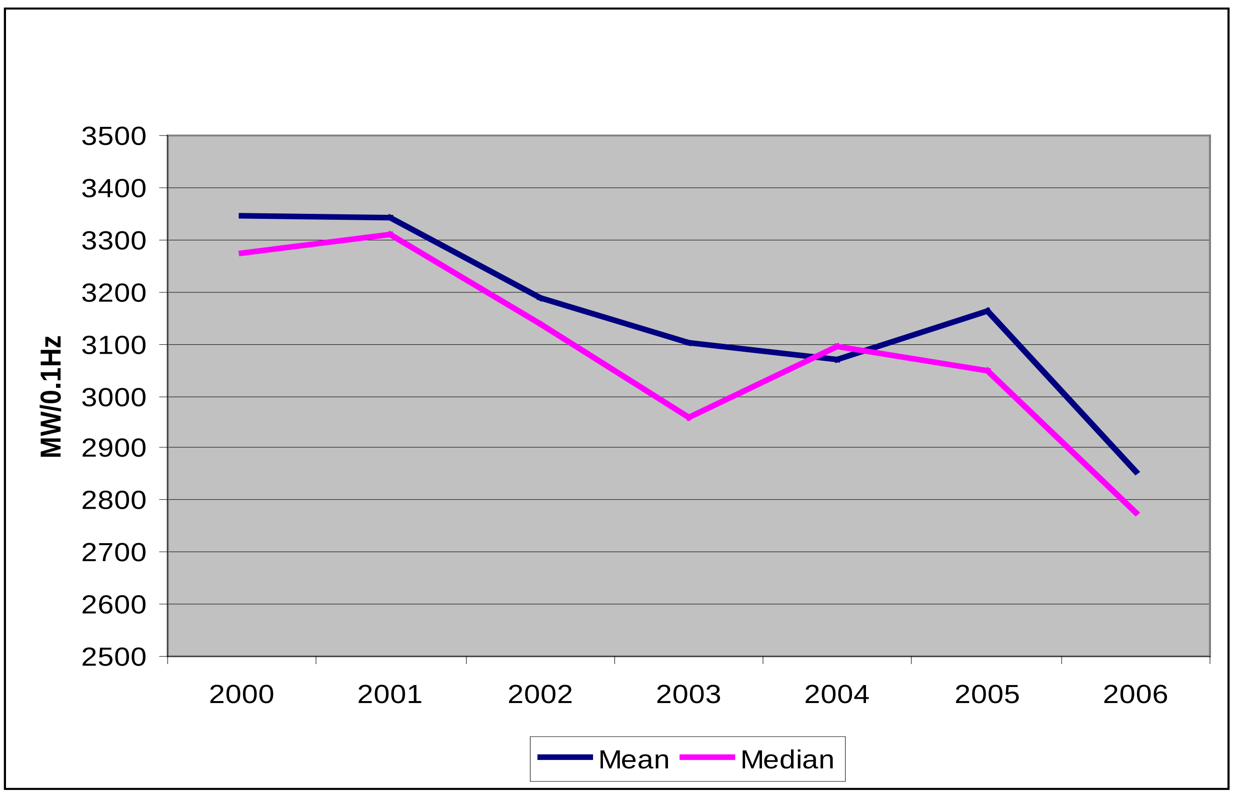


Figure 7 — Recent Eastern Interconnection Frequency Response

Frequency Response Variability
Some have suggested that there should be a standard that requires a minimum amount of frequency response from all Balancing Authorities for all events. Consistency in measuring and controlling this would be problematic.

The calculated beta[8] for a Balancing Authority is based on measuring a relatively small change in Net Actual Interchange coincident with a frequency excursion. Load and generation continuously change in a Balancing Authority. Any random variation in load or generation that happens to occur at the time of the disturbance will greatly misstate the calculated beta for that event. An objective estimate of Balancing Authority beta should be based on 30 or more events dispersed throughout the year. Using the median value will eliminate the impact of misstated individual events.

There is a great deal of variability of Beta or Interconnection Frequency Response by season and day of the week. Beta may be larger during peak periods because there are more contributing generators and motors.

Most observed frequency excursions in the Eastern Interconnection are caused by:

- Generator trips.
- Schedule changes (resulting in significant generation changes) at the top of the hour, particularly during the on-peak to off-peak transitions.
- Pumped storage generation starts/stops.

A given MW-sized event will cause a larger frequency excursion during periods of low Beta than during periods when Beta is higher. As such, some events of a given size will not cause a noticeable change in frequency during peak periods that have a large Beta, yet an event of the same size might cause a significant frequency shift during periods with low Beta.

Figure 8 shows the variability of Interconnection Beta indirectly by tracking the number of sufficiently large[9] frequency excursions by month of the year and day of the week. Notice that there are few frequency excursions during the peak months, but many excursions on the light-load months, and in particular, on weekends. This implies that an objective estimate of Beta must look at many events throughout the year.

8 A capitalized Beta (which looks like a B) typically applies to the Frequency Response of an Interconnection, while small beta (β) applies to the response of a Balancing Authority.
9 28 mHz was chosen as a “benchmark” for frequency excursions in the Eastern Interconnection by the Resources Subcommittee when Beta was 3500MW/0.1 Hz. At this point in time, a 28 mHz excursion was typically associated with the loss of roughly 1000MW.

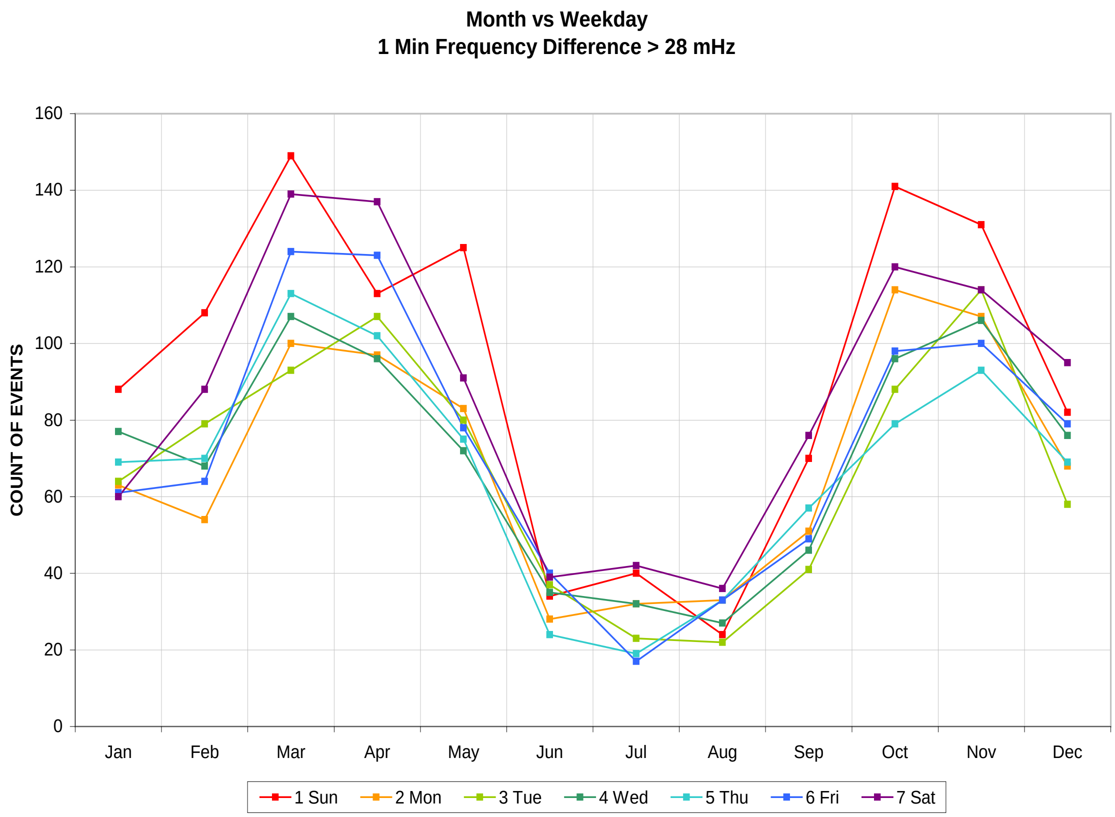


Figure 8 — Frequency Excursions by Month and Day of the Week

Tips on Calculating Frequency Response

The NERC Resources Subcommittee occasionally requests Frequency Response Characteristic Surveys for specific events. The NERC *Frequency Response Characteristic Survey Training Document*, *contained in the NERC Operating Manual*, has a form for calculating Frequency Response for a particular event.

Balancing Authorities should not rely on one or two surveys to establish a value to be used for their Bias. Statistical theory says about 30 observations are needed to give a large enough sample to have confidence in the results. The median of these samples is a better indicator of central tendency when measuring a highly variable population like Frequency Response events.

Because of the work involved, few Balancing Authorities go through a statistically rigorous approach to calculate their Bias. Most simply use the "1 percent of load" approach. The value in a Balancing Authority properly stating its Bias is to "tune" AGC to the natural response of its load and generation.

So how have Balancing Authorities obtained the observations to be used for calculating their Bias? There really has not been a standard way to do this. In some cases, Balancing Authorities have implemented automatic tools that scan for frequency events and archive data. Others just rely on their operators to spot frequency events and make a log entry somewhere so that someone can go back and pull the appropriate data (either electronic or even paper charts).

The NERC Resources Subcommittee has lists of excursions available to the industry for everyone's use for calculating Frequency Response. On request, they will post such events on their Web page.

Date	Time	ANI "A"	ANI "B"	Frequency "A"	Frequency "B"	Response
1/7/02	13:02	25	7	60.010	59.965	40.0
1/21/02	16:12	-37	-30	59.980	59.962	-38.9
2/16/02	6:07	203	167	60.011	59.97	87.8
2/22/02	9:17	-72	-84	60	59.963	32.4
2/27/02	6:33	18	19	60.01	59.97	-2.5
3/5/02	17:15	-204	-255	59.99	59.928	82.3
3/9/02	21:30	-111	-131	60.01	59.965	44.4
3/22/02	16:15	35	17	60.025	59.971	33.3

34.9	Average Response
36.7	Median Response
8	Number of Events

Table 2 – Frequency Response Calculator

Table 2 demonstrates how a Balancing Authority can go about calculating its Frequency Response from several events. The table is nothing more than a spreadsheet that takes Net Actual Interchange and Frequency at points A and B and calculates both individual and cumulative Frequency Response.

Table 2 is also an embedded spreadsheet. "Double clicking" on the table will open the spreadsheet. If you are interested in saving the sheet to calculate local Frequency Response, all you have to do is open the spreadsheet, then copy and paste it into a regular spreadsheet.

New Tool: NERC is implementing a Frequency Monitoring project developed by the Consortium for Electric Reliability Technology Solutions (CERTS), sponsored by the Department of Energy (DOE). As part of the project, you can receive e-mail notifications associated with frequency excursions that would be candidates for calculating responses. If you are interested, contact your NERC Resources Subcommittee representative.

Once a Balancing Authority calculates its Frequency Response, it must make a decision on what Bias it will report to NERC by January 1 and use in its ACE calculation. The following are the options to consider:

- The best approach is to use a Bias that reflects natural Frequency Response for all the observed excursions.
- If natural Frequency Response is less than 1% of projected peak load or generation, Bias must be set such that it complies with the BAL-003 requirement that the monthly average value of Bias be at least 1% of projected peak load or generation (see standard for details).
- The Control Performance Standard does provide some room for Balancing Authorities to select a Bias as part of a control strategy, provided they observe BAL-003 R2 and R5. For example, Balancing Authorities with large, rapidly-changing ("nonconforming") loads such as arc furnaces that cause problems meeting CPS2 may want to increase their

Bias beyond their natural response. This causes their units to do more regulating (or a decline in CPS1 for the same amount of regulating) as a trade-off for getting larger L10 limits. (The size of CPS2's L10 is related to Bias.)

Unless the process is automated, there is a fair amount of effort required in objectively calculating Frequency Response.

Calculating Frequency Response is not a new requirement. Many Balancing Authorities do this in order to calculate and set their bias. Those that do this manual task understand the challenges involved.

Figure 5 shows actual scan rate response for a medium-sized Balancing Authority for five events in 1998. The chart is a graph of the Balancing Authority's "Tie Deviation" in MWs plotted against time. The chart shows the Tie Deviation from 60 seconds before a frequency excursion until 60 seconds after the excursion.

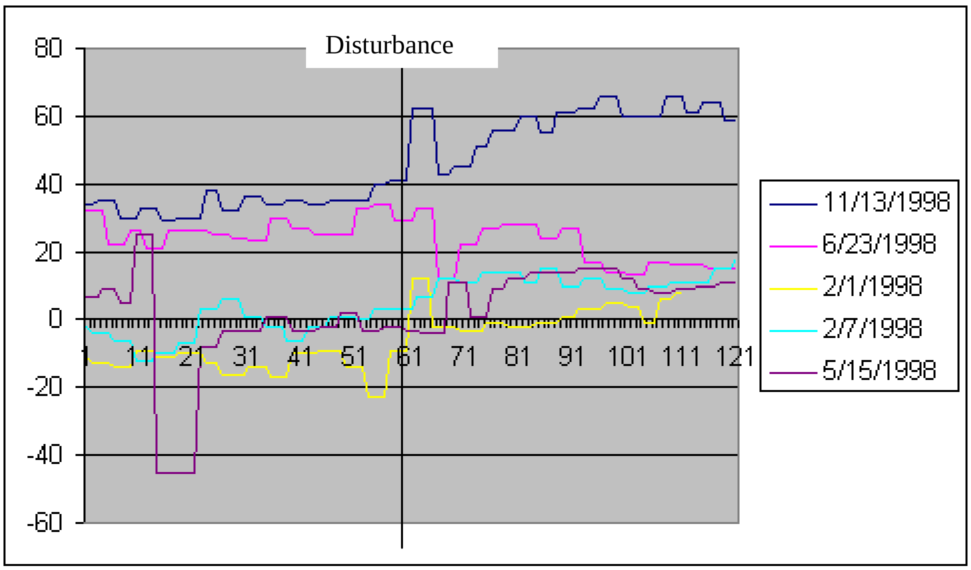


Figure 9 – Frequency Response for 5 Events

For the time being, assume all five frequency excursions were 33 mHz. The reader can refer to the *Frequency Response Characteristic Survey Training Document* for the actual calculation, but Frequency Response is simply:

[MWs deployed /0.1 Hz of frequency deviation]

Since 33 mHz is one-third of 0.1 Hz, it seems all we have to do is multiply the change in Balancing Authority output by 3. For those familiar with the process, two problems immediately arise.

First, the *Frequency Response Characteristic Survey Training Document* says to use the interchange values "immediately before" and "immediately after" the disturbance to derive a value for MWs deployed for the event. The reader is asked to actually determine and write down the "MW deployed" for these events. It is almost certain your answer will be different than another person who reads the same graph. Given a frequency excursion of 33 mHz, a difference in calculation of 5 MW of tie deviation means a difference of 15 MWs in Frequency Response. Obviously, there is a need to be more explicit in the methodology and to find a way to take the subjectivity out of the process.

Second, a scan of Figure 5 shows that the Balancing Authority actually had a negative response for the June 23 event. This brings up another underlying problem with measuring Frequency Response. Short of measuring every generator individually, there is no way to separate Frequency Response from normal load variations for a single event. To remove the effect of load variation at the Balancing Authority level, many events should be measured and a statistical average response calculated. If enough events are captured, the effect of load variations will be reduced (because load swings are equally likely to inflate or decrease the calculated Frequency Response).

- There is significant variation in a single Balancing Authority from event to event. This means that the selection process for events to be measured markedly affects the results. If every Balancing Authority is not working off the same selection criteria or the same set of events, it is likely that results will be inconsistent.
- Some Balancing Authorities calculate their response from paper "Net Interchange" charts. The scale on these charts is such that it is difficult to identify the "blip" that corresponds to the frequency excursion. CPS source data is digital to several decimal places, and thus less subjective.
- Refer back to Figure 5 and consider the manual process that exists today. It is unlikely that given the objective data in the graph that two people calculating response for these events manually would come up with matching answers. Using CPS data takes subjectivity out of the process.
- *The Frequency Response Characteristic Training Document* leaves room for interpretation on the time window to measure. The document talks about using the Interchange and Frequency values "immediately before" and "immediately after" the event. This is subject to interpretation. Using CPS data takes subjectivity out of the process.
- On the average, little automatic generation control (AGC) occurs within a single minute timeframe. Even though there will be some random load and generation swings in each event, their effects will be netted out over many events.

Frequency Response Profiles of the Interconnections

The amount of frequency decline from a lost generator varies based on time of day, the season, as well as the Interconnection. The Frequency Responses of the North American Interconnections are on the order of:

- -2,760 MW / 0.1Hz (Eastern Interconnection)
- -650 MW / 0.1 Hz (Texas Interconnection – ERCOT)

- -1,482 MW / 0.1 Hz (Western Interconnection – WECC)
- -120 MW / 0.1 Hz (Quebec Interconnection)

Important Note: The values in this section are approximations based on currently available data.

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 on the order of:

- -0.036 Hz (East)
- -0.154 Hz (Texas)
- -0.067 Hz (West)
- -0.833 Hz (Quebec)

Conversely, if 1000 MW of load were lost in an Interconnection, the resulting frequency increase would be similar in magnitude as listed above. In ERCOT it has been observed that typical response to high frequency events is approximately 2/3 of the frequency response for low frequency events.

Figure 10 is a typical trace following the trip of a large generator in the Eastern Interconnection, while Figure 11 is a trace from ERCOT. Notice that governors in the East do not provide the "point C to B" recovery of frequency as they do in the other Interconnections. Another observation in the East is that there is often some decline of frequency towards the end of the first minute following the event. It is believed this is due to setpoint control at both generating stations and in the Balancing Authorities' control systems. More investigation is needed to specifically identify the cause of this behavior.

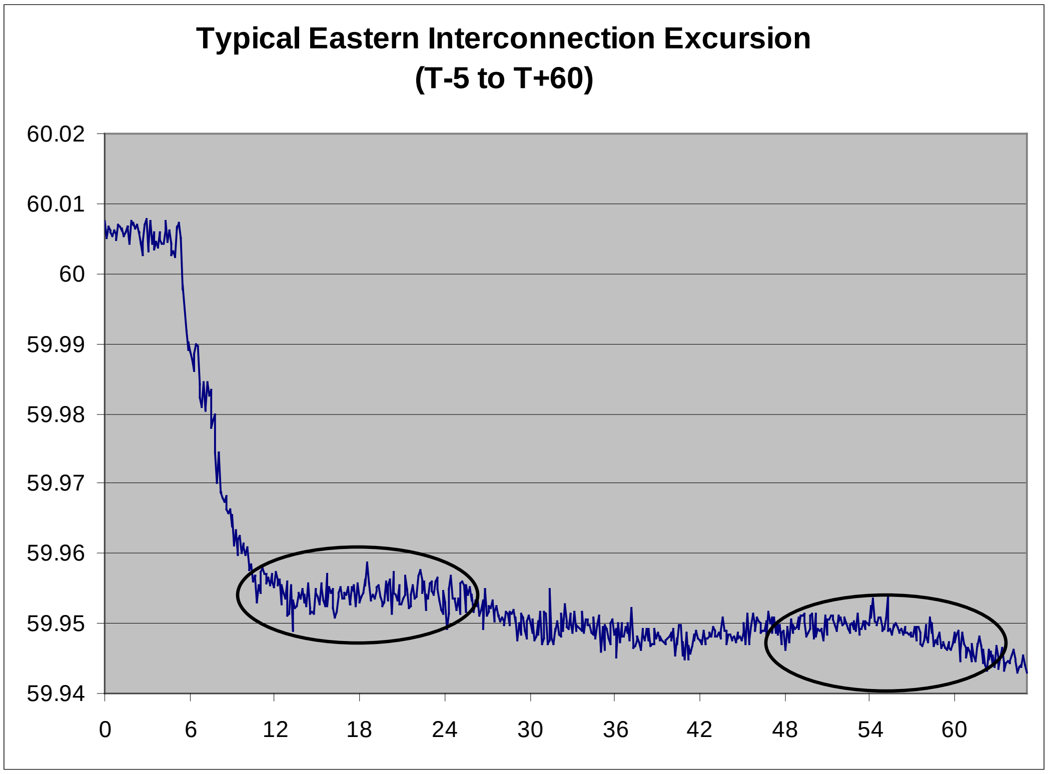


Figure 10 — Typical Eastern Interconnection Frequency Excursion

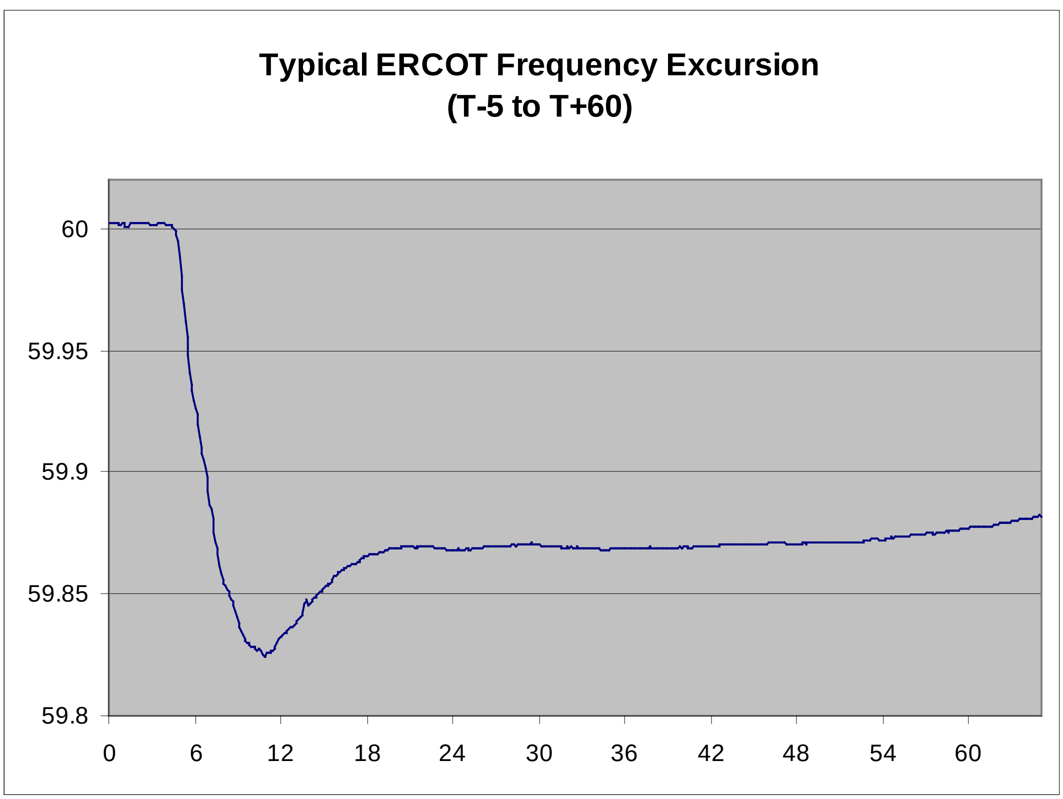


Figure 11 — Typical ERCOT Frequency Excursion

Important Concept: Following a large generator trip, Frequency Response will only stabilize the frequency of an Interconnection, arresting its decline. Frequency will not recover to schedule until the contingent Balancing Authority replaces the lost generation through AGC and reserve deployment.

Annual Bias Calculation

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

The NERC Resources Subcommittee has lists of excursions available to the industry for everyone's use for calculating Frequency Response. One may have been provided along with this document.

Guidelines in selecting and evaluating events for calculating Bias include:

- If possible, avoid using events where you or a neighboring Balancing Authority caused the frequency decline. Tie-line data typically goes through wide swings when this is the case.
- Ensure events are dispersed throughout the year to get a good representation of "average" response.
- Pick frequency excursions large enough to actuate generator governors. This would require excursions of at least 36 mHz (.036 Hz), because some governor references use this as a deadband setting. With some older governors unable to resolve better than 50 mHz, excursions of at least this magnitude may prove even more useful.

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 to 2 percent of load. Techniques have been developed to observe approximately how much "load" frequency response a Balancing Authority actually has. This technique is explained below.

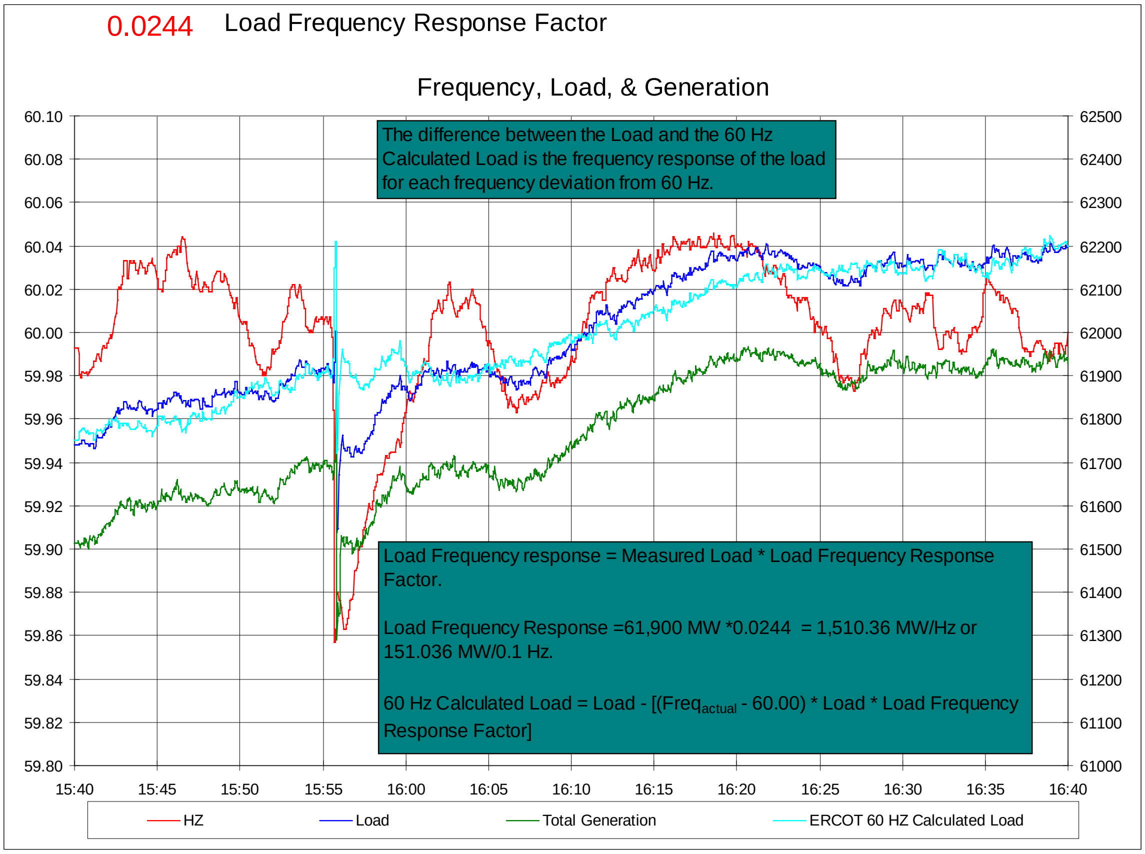


Figure 12 Observing Frequency Response of Load

The cyan trend in **Figure 12** 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 759/(0.118*10) = 643 MW/0.1 Hz of frequency response. Of this response, 151.036 MW/0.1 Hz was provided by the load (by multiplying the load by .00244) which leaves 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 replacing 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 -759MW at the B point of this event. AGC would dispatch 759 MW to replace the frequency response of the governors and load which would return the Interconnection to balance at 60.00 Hz. This example is of a "single" Balancing Authority 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 as well as 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 BA boundaries.

Key Points (Primary Control)

- Steady-state frequency is common throughout an Interconnection.
- If frequency is off schedule, generation is not in balance with total load at the load's value for scheduled frequency.
- Arresting frequency deviations is the job of all Balancing Authorities. 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).
- Frequency Response is the sum of a Balancing Authority's natural load response to frequency and the governor response of generators within the Balancing Authority.
- Frequency Response arrests a frequency decline, but does not bring it back to scheduled frequency. Returning to scheduled frequency occurs when the contingent Balancing Authority restores its load-resource balance.
- 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 Balancing Authorities 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 (Balancing Authority output increases as frequency declines) expressed in MW/0.1Hz.
- The typical (best) way to calculate Frequency Response is to observe the change in Balancing Authority output for several (many) events over a year.
- A Balancing Authority should set its Bias to no less than its natural Frequency Response, and to at least 1% of predicted system peak load (or generation) per BAL-003.
- The Eastern Interconnection has a Frequency Response of roughly 2,750 MW/0.1 Hz. This means the loss of a 1,000 MW generator will drop frequency roughly 0.036 Hz.
- The Western Interconnection has a Frequency Response of roughly 1,500 MW/0.1 Hz. This means the loss of a 1,000 MW generator will cause the frequency to drop approximately 0.06 to 0.07 Hz.
- Most Balancing Authorities use the "1% of peak load" method to calculate their Bias. This is roughly twice the observed Frequency Response in the Eastern Interconnection.
- Governors were the first form of control, and remain at the vanguard today. They act to mitigate frequency change.
- 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 timeframe, 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)
- The Frequency Response is declining in the Eastern Interconnection and appears to be declining in the Western Interconnection. One underlying issue is that nobody knows if the decline is spread out among all Balancing Authorities or if there are pockets with substandard response. Neither situation is an immediate threat for steady-state reliability. However, Frequency Response is vital during disturbances and islanding.
- Area frequency response should be measured for two reasons.
  - Most importantly, to gauge the area response to frequency upsets,
  - Secondarily, as a basis for setting B.

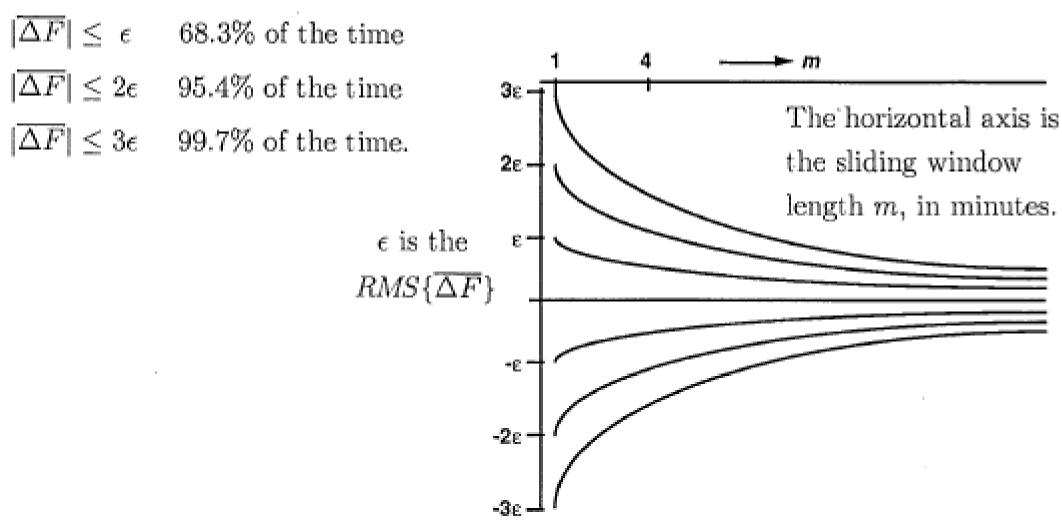
Secondary Control

Background
Secondary Control is the combination of automatic generation control (AGC) and manual dispatch actions to maintain energy balance and scheduled frequency. In general, AGC utilizes maneuvering room while manual operator actions (phone calls to generators, purchases and sales, load management actions) keep repositioning the Balancing Authority Area so that AGC can respond to the remainder of the load and Interchange Schedule changes. The NERC Control Performance Standards are intended to be the indicator of sufficiency of Secondary Control.

Whither the Frequency Profile Requirement?
The most basic indicator of proper Secondary Control action is the character 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 (deviation) to become any worse 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 figures 14a and 14b. Although other values could have been selected, and ideally ALL values should be considered, the averaged values looked at most closely were those for 1 minute and 10 minutes. This was for practical reasons; computing all the interval averages would be computationally burdensome and, arguably, unnecessary if frequency performance could be made (more) random.

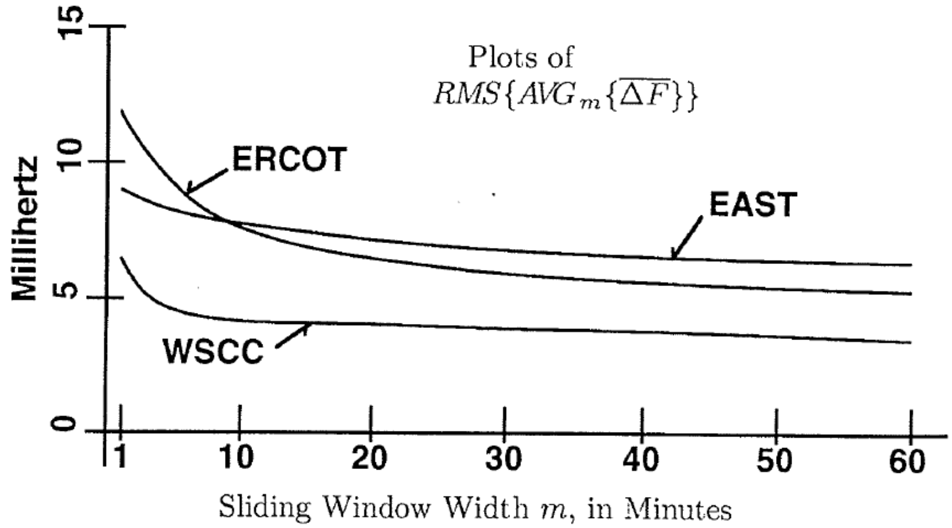
To set values for frequency performance, each interconnection’s frequency error was observed using the above method, and each one was characterized, particularly at their 10-minute interval average RMS frequency deviation from schedule. The eastern interconnection measured 5.7 mHz at the 10-minute point. 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 5.4 * 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 WECC and ERCOT interconnections. It is important to realize that CPS1 performance, described in the next section, 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 error will be constrained at other averaging points or converge on the ideal characteristic and become more random. CPS2 does impose limits on deviations of ACE at 10-minute averages (intended to help prevent excessive transmission flows due to ACE fluctuations), but this does not assure the desired random behavior, either.



A normally distributed $\overline{\Delta F}$, which had no structure in its trend and was 68.3% of the time within $\pm\epsilon$, would give sliding averages that would be within the narrowest funnel 68.3% of the time. The same averages would be within the second funnel 95.4% and within the largest funnel 99.7% of the time, respectively. The funnels taper at a rate of $1/\sqrt{m}$.

Figure 14a – The ideal ΔF characteristic, for random behavior of Balancing Areas, shows an inverse square-root declining "noise" of frequency deviation as the length of the averaging period increases (EPRI report RP-3550, August, 1996).



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 14b — Illustration of actually-measured ΔF "period average" characteristic (EPRI report RP-3550, August, 1996). Note that these curves are flatter than the ideal, with frequency deviation "noise" remaining significant as the averaging period lengthens. Shown are the actual measured characteristics for the East, WSCC, and ERCOT interconnections. The difference between these and the "ideal" is caused by the distribution of the frequency error being non-random in the real world, while it is assumed to be random in the ideal. Hour-crossing schedule changes, diurnal load fluctuations, pumped hydro operation and other such activity drive this characteristic.

Random (non-coincident) behavior of balancing areas, in total, is important in the above assumptions, because as behavior becomes coincident (behaviors happening at the same time) the curves from which epsilon 1s were extrapolated start to deviate from the shape and predictability of the curves used to derive them. 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. One type of coincident behavior is illustrated in Figure 14c below, where time-of-day behaviors relating to diurnal load characteristics and scheduling practices lead to observable clustering of probability of low-frequency events.

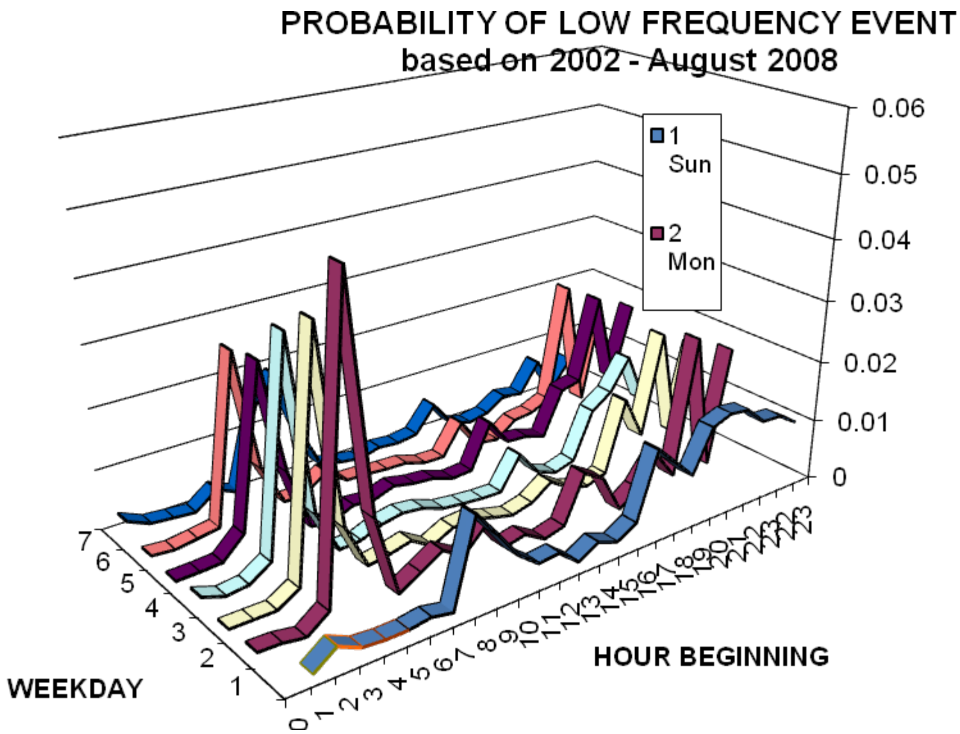


Figure 14c – Probability Distribution for Low-Frequency Events vs. Time of Day

Control Performance Standard 1 (CPS1)
In simple terms, CPS1 assigns each Balancing Authority a share of the responsibility for control of steady-state Interconnection frequency. The amount of responsibility is directly related to Balancing Authority Frequency Bias.

ACE is to a Balancing Authority what frequency is to the Interconnection. Over-generation makes ACE go positive and frequency increase. Negative ACE "drags" on interconnection frequency. "Noisy" ACE tends to cause "noisy" frequency. CPS1 captures these relationships using statistical measures to determine each Balancing Authority'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[10])* (frequency error)*(ACE)]

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

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

Refer to the equation above. Any minute where the average frequency is exactly on schedule or Balancing Authority 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 percent. For example, if frequency is low, but ACE is positive (tending to correct frequency error), the Balancing Authority gets extra CPS1 points.

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 you high CPS1 scores over the long run.

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

ERCOT Note: The ERCOT Interconnection operates as a single Balancing Authority. ACE for a single Balancing Authority Interconnection will always be “in phase” with frequency error (refer to the ACE Review if you don’t see why this is true). This means the largest CPS1 ERCOT can achieve is 200 percent. This occurs whenever ACE or frequency error is zero. CPS1 is a function of “Frequency Squared”

The CONSTANT in the equation above is sized such that if a Balancing Authority’s ACE is proportionally as “noisy” as a benchmark frequency noise, the Balancing Authority will get a CPS1 of 100 percent. The minimum acceptable long-term score for CPS1 is 100 percent.

When CPS was established, each Interconnection was given a target or benchmark “frequency noise”. This target noise is called “Epsilon 1” or ε_1. Epsilon 1 is nothing more than a statistician’s variable that means the RMS (root mean square) value of the one-minute averages of frequency.

The target values (in mHz (millihertz) of frequency noise) for each Interconnection are shown in Table 1 below. The NERC Resources Subcommittee monitors each Interconnection’s frequency performance and can tighten (or loosen) the ε_1 values should an Interconnection’s frequency performance decline (improve).

Interconnection	Epsilon 1
Eastern	18.0
Hydro Quebec	21.0
Western	22.8
ERCOT	30.0

Table 3 Target Values of "One Minute Frequency Noise"

The Epsilon 1 target initially set for each Interconnection was on the order of 1.6 times historic frequency noise. This should permit Balancing Authorities, performing at historic "average" compliance, to score around 160% for CPS1.

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 refers to these resources as Interconnected Operating Services (IOS). Although there are some differences in definitions, the FERC calls these services Ancillary Services.

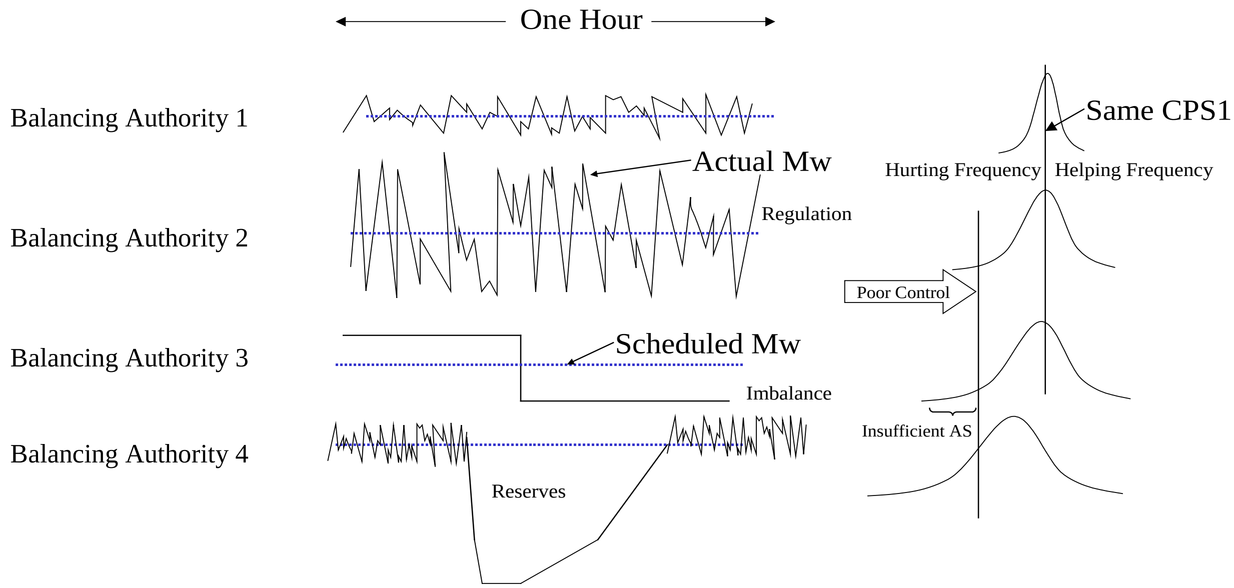


Figure 15 — IOS/Ancillary Service Measured via CPS

Figure 15 depicts ACE charts for one hour for four different Balancing Authorities. Compare the charts for Balancing Authorities 1 and 2. Both Balancing Authorities show good performance for the hour. The difference between them is that the load in Balancing Authority 2 is "noisier".

The "bell curves" to the right of the ACE charts show the distribution of the individual one-minute CPS1 for both Balancing Authorities for the hour. If frequency followed a normal pattern, whereby it fluctuated +/- a few mHz from 60 Hz, the CPS1 curves for Balancing Authority 1 and 2 would look like the "bell curves" to the right of their ACE charts. Both curves would have the same average (about 160 percent CPS1), but Balancing Authority 2's curve would be "wider". In other words, the larger ACE swings would sometimes help frequency back to 60 more than Balancing Authority 1, but sometimes hurt frequency more than Balancing Authority 1.

Even though the average effect of Balancing Authority 1 and 2 on the Interconnection is the same, Balancing Authority 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 (in this case regulation).

Now look at Balancing Authority 3. It is a "generation only" Balancing Authority 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 of the hour. Again, if frequency conditions are normal, half the time the Balancing Authority will be helping frequency back towards 60 Hz and half the time the Balancing Authority will be hurting frequency. This means the Balancing Authority will get an "Interconnection average" CPS1 score of about 160 percent for the hour. The graph of its CPS1 for the hour will have wider tails, much like Balancing Authority 2. The underlying problem in this case is Imbalance, not Regulation.
The ACE chart for Balancing Authority 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 IOS (sometimes called ancillary services). The "left tail" of the underlying CPS1 curve captured each situation.

Extremely positive CPS1 (irrational control) is achieved in one of two ways:

- Significant over-generation during low frequency. Low frequency is generally associated with high energy prices. Creating positive inadvertent rather than selling energy into a market is irrational.
- Significant under-generation during high frequency. If a resource is lost during a period of extended high frequency, there are typically many possible suppliers that can be called upon to help correct the situation.

Control Performance Standard 2 (CPS2)

CPS2 is a "safety valve" standard that was put in place when CPS was developed. There was concern that if CPS1 was the only regulating standard, a Balancing Authority could grossly over or under generate (as long as it was opposite the frequency error) and get very good CPS1, yet impact its neighbors with excessive flows.

Table 4 shows the general relationship between Balancing Authority size and the size of the L_{10} band for the Eastern Interconnection. The table assumes the Balancing Authorities use the "1% of load" method to determine their Bias obligation.

BA Size (MW)	$L_{(10)}$ (MW)
10	2
50	5
100	7
250	12
500	17
1000	23
2500	37
5000	52
10000	74
15000	91

Table 4 Approximate L10 Limits vs. Balancing Authority Size (Eastern Interconnection)

Balancing Authorities using variable Bias have L_{10} limits that change slightly throughout the day.

CPS2 says that for each 10-minute period, the average ACE for a 1000 MW Balancing Authority must be less than 23 MW. Any clock 10-minute period (there are six per hour) greater than 23 MW (no matter if it's 1 MW more or 100 MW more) is a violation of the limit for that 10-minute period. Performance requires that there be no violations in at least 90% of the 10-minute periods of a month and is calculated by:

CPS2 (percent) = 100 * (periods without violations)/(all periods in the month)

The minimum acceptable CPS2 for a month is 90%. This means that on the average, a Balancing Authority may have roughly one violation ever other hour and still pass CPS2.

The actual L10 limits change slightly each year, based on bias calculations submitted to NERC. These limits can be found on the NERC Resources Subcommittee web page.

Quick Review:
- CPS1 assigns each Control Area a share of the responsibility for control of Interconnection frequency.
- CPS1 is a yearly standard that measures impact on frequency error, with a 100 percent minimum allowable score.
- CPS2 is a monthly standard intended to limit unscheduled flows.
- The minimum allowable CPS2 score is 90 percent.

Tertiary Control
The UCTE Operation Handbook defines Tertiary Control as any (automatic or) manual change in the working points of generators (mainly by re-scheduling), in order to restore an adequate

SECONDARY CONTROL RESERVE at the right time. This would include actions such as adjustments to scheduled interchange and deployment of additional generation resources.

Understanding Reserves

There is often confusion when operators and planners talk about reserves. One major reason for misunderstandings 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, which means there are many different expectations and obligations across North America.

The second area of confusion concerning reserves deals with the limitations of each Balancing Authority's energy management system (EMS). Common problems include:

- Counting all "headroom" of on-line units as spinning reserve, even though it may not be available in 10 minutes.
- No intelligence in the EMS regarding load management resources.
- No corrections for "temperature sensitive" resources such as gas turbines.
- Inadequate information on resource limitations and restrictions.
- Reserves which may exist and are deployed outside the purview of the EMS system.

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 16** to better understand the definitions.

Contingency Reserve: The provision of capacity deployed by the Balancing Authority to meet the Disturbance Control Standard (DCS) and other NERC and Regional Reliability Organization contingency requirements.

Curtailable Load: Load that can be disconnected from the system with assurance in less than one hour.

Frequency-Responsive Reserve: On-line generation with headroom that has been tested and verified to be capable of providing droop <= 6% with a deadband <= 36 mHz. Variable Load that mirrors governor droop and deadband may also be considered Frequency Responsive Reserve. In most cases, only portions of a, b and c in Figure 16 qualify as Frequency Responsive Reserve.

Interruptible Load: Load under direct control of an operator that can be interrupted within 10 minutes.

Nonspinning Reserve: Operating Reserve capable of serving demand or Interruptible Demand that can be removed from the system, within 10 minutes. (This is c in Figure 16)

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. (This is a+b+c+d+e in Figure 16).

Other Reserve Resources: Resources that can be brought to bear outside the continuum of Figure (i.e. on four hours' notice).

Planning Reserve: The difference between a Balancing Authority's expected annual peak capability and its expected annual peak demand expressed as a percentage of the annual peak demand.

Projected Operating Reserve: This is a+b+c+d+e in Figure for those resources expected to be deployed (or available in the time windows in Figure 16) for the point in time in question.

Regulating Reserve: An amount of spinning reserve responsive to Automatic Generation Control, which is sufficient to provide normal regulating margin. (This is "a" in Figure 16 .)

Replacement Reserve: (This is d+e in Figure 16). NOTE: Each NERC Region sets times for reserve restoration, typically in the 30–90 minute range. The default contingency reserve restoration period is 90 minutes after the disturbance recovery period.

Spinning Reserve: Unloaded, synchronized, resource, deployable in 10 minutes. (This is b in Figure 16).

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. Also referred to as non-spinning reserve. This is effectively FERC's equivalent to NERC's Non-Spinning reserve (c in Figure 16).

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. Reserves can also be misstated. It is important to look at other indicators to determine the ultimate course of action, such as:

- Is the Balancing Authority(s)' ACE predominantly negative for an extended period?
- Is frequency low (more than 0.03 Hz below scheduled frequency)?
- Are reserves low in multiple Balancing Authorities?
- Is load trending upward (are higher loads anticipated)?

Based on the duration and severity of the situation, action steps would include:

- Verify reserve levels
- Follow EEA
- Direct Balancing Authority(s) to take action to restore reserves
- Redistribute reserves

- Shed load where appropriate if the Balancing Authority or Transmission Operator cannot withstand the next contingency.

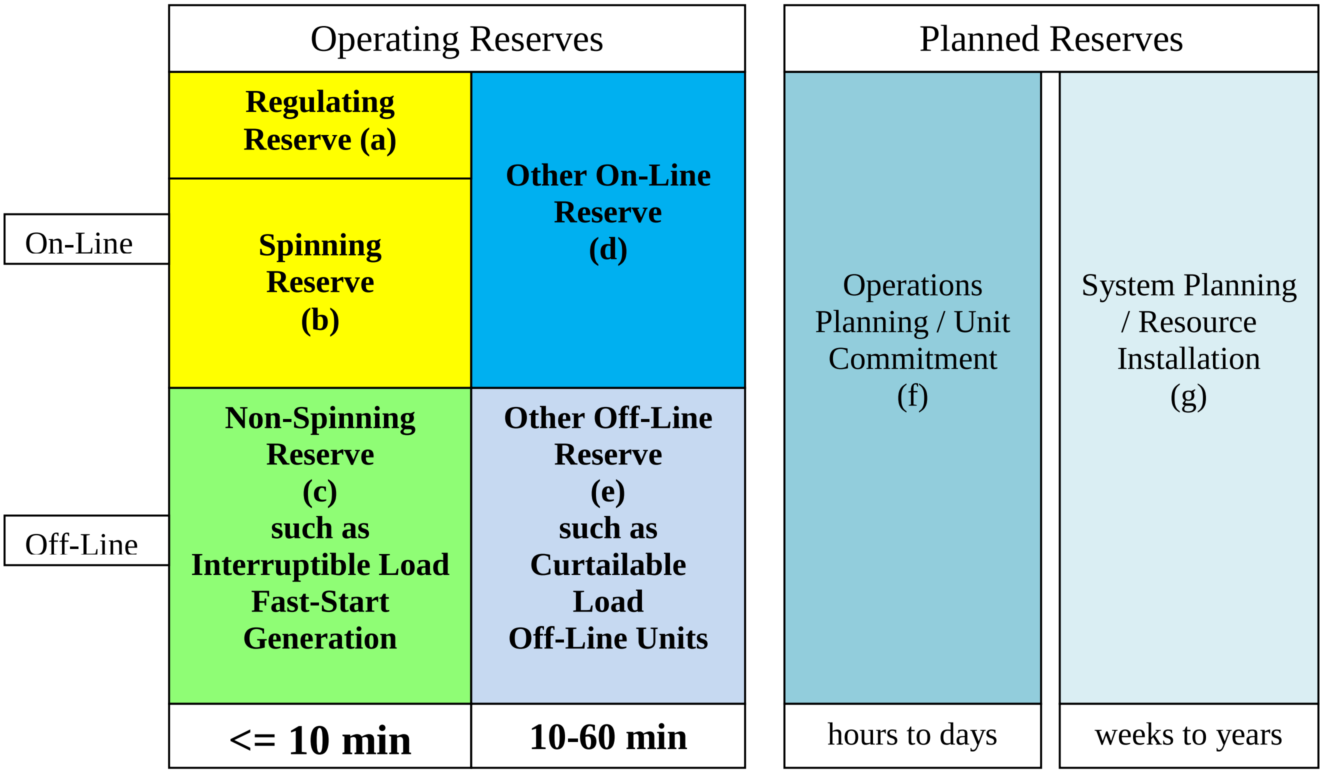


Figure 13 Reserves Continuum

Measuring Performance rather than the Commodity
The traditional measure of resource adequacy is to track operating reserves. A simplified calculation for reserves is Balancing Authority's generating capability minus customer demand. There are actually several different types of reserves (spinning, non-spinning, regulating, contingency, replacement), but all are intended to maintain or restore load-generation balance in different windows of time.

There are four underlying problems with determining adequacy by measuring reserves as a commodity rather than the performance or outcome (restoring load-generation balance):

- Reserves are almost always misstated. Demand forecasts are not precise and projected generating capability may be based on ideal conditions.
- Because of the differing requirements across the country (for example, planning reserve obligations are typically the purview of state commissions) the industry has no standard definition for reserves or process for verifying reserves.
- Not all Balancing Authorities need the same amount and type of Operating Reserves. Balancing Authorities with large arc furnace loads need more regulating (quick maneuvering) generation than others. Balancing Authorities that can import power from

multiple directions need less reserve than a Balancing Authority that has only one neighboring Balancing Authority. Balancing Authorities with less reliable generators or very large generators need more reserves. Balancing Authorities with a preponderance of one fuel source for its generation should have more reserves than neighbors with more diverse fuel supplies.

- Rate and quality of response by reserves vary among different generators and are not always predictable. Actual rate of response is often smaller than the value specified for the unit, and other factors, such as the time delay before generators start responding needs to be considered. Balancing Authorities without methods to accurately evaluate and mitigate issues in regulation response need more reserves.

Even if a Balancing Authority has adequate reserves, it may fail or be unable to deploy them when needed. If, however, a Balancing Authority continuously balances load and resources within objective bounds, it demonstrates through performance that it has enough reserves to meet its needs and fulfill its obligations to the Interconnection.

Time Control and Inadvertent Interchange

Background

There is a strong interrelationship between control of Time Error and Inadvertent Interchange. Time Error occurs when one or more Balancing Authorities has imprecise control, causing average actual frequency to deviate from scheduled frequency. The Bias term in the ACE equation of the remaining Balancing Authorities causes control actions that result in flows between Balancing Areas 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 Balancing Authority Areas 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 a Reliability Coordinator as a “Time Monitor” to coordinate Time Control.

Time Error Corrections are initiated when long-term average frequency drifts from 60 Hz. In the Eastern Interconnection, 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 numbers of TECs do provide a benchmark for the quality of frequency control and also 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 TECs.

Inadvertent Interchange

Inadvertent Interchange is net imbalance of energy between a Balancing Authority 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 Balancing Authority's 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 Balancing Authority's 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 Balancing Authority. 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 (MWhr), 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 to reduce inadvertent energy balances

Secondary Inadvertent
Balancing problems external to a Balancing Authority will cause off-schedule frequency. If frequency is low, the bias term of the ACE equation will cause a Balancing Authority to slightly over-generate (after initial effects, such as governor response and load damping, stabilize) to stabilize frequency. Conversely, if frequency is high, the bias term of the ACE equation will cause a slight under-generation. This intentional outflow or inflow to stabilize frequency due to problems outside the Balancing Authority is called Secondary Inadvertent Interchange.

Quick Review: If one or more Balancing Authorities have a control problem, it will cause them to have a large Primary Inadvertent Interchange. This may also cause off-normal frequency, which spreads Secondary Inadvertent Interchange to the other Balancing Authorities. The off-normal frequency then results in accumulated Time Error, which may trigger Time Error Corrections.

Frequency Correction and Intervention

Background

There are several requirements in the NERC reliability standards that tell the Balancing Authority, Transmission Operator and Reliability Coordinator to monitor frequency and control frequency. The standards do not provide specific guidance on what is normal frequency and under what conditions the operator should intervene. This section provides guidance based on the underlying research done to support the draft Reliability Based Control Standard. The trigger points below are designed for the Eastern Interconnection. There may be differences in the other Interconnections based on their field trial experience.

As noted early 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 Balancing Authority ACE Limit (BAAL) is the ACE-frequency combination equivalent to instantaneous CPS1 of -572%[11]**.** In general, if one or more of the RC's Balancing Authorities is beyond the BAAL for more than 15 minutes, the RC should contact the Balancing Authority to determine the underlying cause. As frequency diverges more from 60 Hz, the RC and BA should be more aggressive in their actions.

The primary responsibility of the RCs under the draft Reliability Based Control standard is protection of frequency. Suggested actions are outlined below.

11 As a clarification, the BAAL is based on a snapshot CPS1 calculation that uses deviation from 60Hz rather than deviation from scheduled frequency.

Short-Term Triggers (Reliability Coordinators)

Frequency	What	Actions
60.5	FRL High	1,4
60.2	FAL High	1,3
60.05 (>10 minutes)	FTL High	1,2
60.05 (>5 minutes	FTL High	1,
59.95 (>5 minutes)	FTL Low	1,
59.95 (>10 minutes)	FTL Low	1,2
59.91	FAL Low	1,3
59.82	FRL Low	1,4

1. Look for 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 Resources Subcommittee (after the fact).

4. Evaluate whether still interconnected. Direct emergency action.

NERC Tools

Short Description of the RS-Sponsored Tools

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Review Questions

The questions below are intended as a resource for the development of local training programs. Trainers are encouraged to submit additional questions to balancing@nerc.com.

Primary Control

1) System frequency:
   a) Measures load-resource balance in an Interconnection or island
   b) Changes in direct relation to generator voltage
   c) Varies from Balancing Authority to Balancing Authority
   d) All of the above
2) How does a Balancing Authority determine the frequency Bias it should use
   a) The same value of the previous year unless a new generator is added
   b) The greater of generation or load multiplied by the L10 limit
   c) Measure the actual response to several frequency deviations
   d) None of the above
3) Generation external to your Balancing Authority has tripped. Which of the following would you expect to see?
   a) Frequency above 60 Hz
   b) Increased net interchange out
   c) Reduced net generation on your system
   d) All of the above
4) The frequency Bias setting used by a Balancing Authority -may be calculated:
   a) As a fixed value
   b) As a variable value
   c) Using a percentage of governor droop from jointly owned units for dynamic scheduling or pseudo-tie control
   d) All of the above
   e) None of the above
5) The minimum recommended frequency Bias setting used by a Balancing Authority that serves load is:
   a) 1 percent of the annual peak demand per 0.1 Hz change
   b) 2 percent of the annual peak demand per 0.1 Hz change
   c) 5 MW/0.1 Hz
   d) –5 MW/0.1 Hz

e) None of the above

6) The minimum recommended frequency Bias setting for a Balancing Authority that does not serve native load is:

   a) 1 percent of the estimated maximum generation level for the upcoming year per 0.1 Hz change

   b) 2 percent of the estimated maximum generation level for the upcoming year per 0.1 Hz change

   c) 5 MW/0.1 Hz

   d) –5 MW/0.1 Hz

   e) None of the above

Use the following data to answer questions 7 and 8.

Assume a Balancing Authority's Bias setting is –50 MW/0.1 Hz. ACE is initially 0 and frequency is 60.00 Hz. Suddenly, a disturbance elsewhere drops frequency to 59.96 Hz. If the actual Frequency Response characteristic for your Balancing Authority for this event is –35 MW/0.1 Hz:

7) What direction is the instantaneous inadvertent interchange on your system at 59.96 Hz?

   a) Received into your system

   b) No inadvertent (0)

   c) Delivered out of your system

   d) None of the above

8) What is the direction of your instantaneous ACE at 59.96 Hz?

   a) Received into your system

   b) ACE is zero

   c) Delivered out of your system

   d) Not necessarily any of the above

9) All generator governors have a droop setting. NERC recommends all generator governors be set at a 5% droop. What does a 5% governor droop setting mean?

   a) The generating unit is allowed to move 5% of its rated load for a frequency deviation of 0.1 Hz

   b) The generating unit is set to cover 5% of the Balancing Authority system load in response to a frequency deviation of 0.1 Hz

   c) The generating unit will cover 5% of its rated load in a ten-minute period in response to a frequency deviation of 0.1 Hz

d) The generating unit will cover its entire load range (0 MW to full load) for a 5% change in frequency

e) None of the above

10) The emergency reserve inherent in the Interconnection's Frequency Response is to be used:

a) Whenever a Balancing Authority cannot afford emergency assistance

b) Only as a temporary source of emergency energy

c) For a period of time not to exceed six hours in a single 24-hour period

d) After all neighboring systems have been polled for emergency capacity availability

11) When providing a certain type of regulation service, a Balancing Authority must incorporate the frequency Bias setting of the Balancing Authority being controlled into its ACE equation. This type of regulation service is known as:

a) Supplemental regulation service

b) Secondary regulation service

c) Overlap regulation service

d) None of the above

12) When providing a certain type of regulation service for another Balancing Authority, the providing Balancing Authority uses only its own frequency Bias setting in its ACE equation. It does not incorporate the frequency Bias of the Balancing Authority for which it is providing regulation service. This type of regulation service is known as:

a) Primary regulation service

b) Supplemental regulation service

c) Time correction regulation service

d) Overlap regulation service

e) None of the above

13) A 1,100 MW generator trips in New York causing a large frequency deviation in the Eastern Interconnection. The NERC survey used to measure the response of every Balancing Authority to the deviation is called the:

a) Area Interchange Error survey

b) Control Performance Standard survey

c) Frequency Response Characteristic survey

d) None of the above

14) If a disturbance reduced the frequency by 0.04 Hz and your Balancing Authority frequency Bias was −100 MW/0.1 Hz, how many MW would your system initially contribute to correcting the problem?

a) 400 MW

b) 0.4 MW

c) 4.0 MW

d) 40 MW

15) Frequency Bias and Frequency Response are:

a) Expressed in MW/0.1 Hz.

b) One and the same.

c) Expressed in MW/cycles of deviation.

d) None of the above.

16) Frequency Bias serves to:

a) Determine the frequency “dead band” of .05 to 1.0 in establishing ACE.

b) Determine MW of response obligation to a given change in frequency.

c) Determine the amount of time error to be automatically corrected by AGC.

d) None of the above is correct.

17) You are doing a perfect job of maintaining a load-resource balance. A large generator in another Balancing Authority has tripped and frequency has dropped to 59.9 Hz. Your frequency Bias is –50 MW/0.1 Hz. If you have done an equally perfect job of setting your frequency Bias, your ACE should be:

a) + 50 MW

b) 0 MW

c) –50 MW

d) None of the above

18) A 1% change in frequency will typically lead to what percent change in the total load?

a) No change

b) 0.1%

c) 1%

d) 2%

19) A governor droop setting is such that the MW output changes by 25 MW for a 0.12 Hz change in system frequency. The maximum output of the unit is 500 MW. What is the value of the droop characteristic? (Nominal frequency is 60 Hz.)

a) 1%

b) 1.2%

c) 4%

d) 5%

20) A power system has ten units on governor control. The units have different capacities (max MW output) and droop settings. The biggest adjustments in MW output in response to a frequency disturbance will be provided by units that have:

a) Large capacity; large droop setting

b) Large capacity; small droop setting

c) Small capacity; large droop setting

d) Small capacity; small droop setting

21) The frequency response characteristic of a power system is defined as:

a) The nominal frequency of the system; 60 Hz in North America

b) The change in Interconnection frequency for 100 MW changes in load or generation

c) The percentage change in system output for a 0.1% change in system frequency

d) The MW change in system output for a 0.1 Hz change in system frequency