NERC

TRAINING RESOURCES WORKING GROUP

Assisting System Personnel
In Keeping Current

# NERC
# Training Document
# Understand and Calculate Frequency Response


Developed by:
NERC Training Resources Working Group


February 20, 2003

# Subject: Understand and Calculate Frequency Response

# Overview

This document reviews the concepts of Frequency Response. It includes a discussion of the importance of Frequency Response and how it is calculated. The goal is to develop a common understanding among all those responsible for the reliable operation of each Interconnection in North America.

It should be noted that NERC Standards in general, and Policy 1 in particular, are undergoing change. There has been discussion of a Frequency Response Standard. Even though standards change, the concepts behind Frequency Response do not.

Suggestions for improvement of this reference can be sent to the NERC Training Resources Working Group.

# What You'll Learn

When you complete this lesson, you should:

- Understand the concepts behind Frequency Response.
- Understand terms associated with Frequency Response.
- Understand the interrelationship between Bias, Frequency Response and Automatic Generation Control
- Know the policy requirements regarding Frequency Response.
- If given a set of control area CPS data (frequency and ACE), calculate the control area's Frequency Response.
- Be able to calculate Frequency Response for your control area (if applicable)
- Have the tools necessary to track, monitor and report a control area's Frequency Response and Bias.

# References

*"Decline of Eastern Interconnection Frequency Response,"* Jim Ingleson and Makarand Nagle, Prepared for the Fault and Disturbance Conference at Georgia Tech, May 1999.
*NERC Policy 1, Generation Control and Performance*
*Frequency Response Characteristic Survey Training Document*
NERC Resources Subcommittee Web Page
NERC Resources Subcommittee Minutes
NERC Training Resources Working Group *CPS Overview* Document
WECC Training Manuals

# Training Time

Estimated training time for this lesson is four hours.

# Frequency Response Discussion

## Background

Most system dispatchers and others involved in the operation of the grid have a general understanding of the requirements regarding Frequency Response and Bias as outlined in *NERC Policy 1*, its appendices, and the *Frequency Response Characteristic Survey Training Document*. However, these documents alone do not provide the reader with an understanding of the "whys" and "what it means to my control area." This lesson is intended to lay that groundwork.

Frequency Response is the characteristic displayed by load and generation within control areas, and therefore an Interconnection, in response to a significant change in load-resource balance. Because the loss of a large generator is much more likely than a sudden loss of load, Frequency Response is typically discussed in the context of a loss of a large generator.

## What Provides Frequency Response?

Figure 1 shows a trace of an Interconnection's frequency resulting from a generating unit trip ("unit trip" is a term meaning a sudden complete loss of a generator).

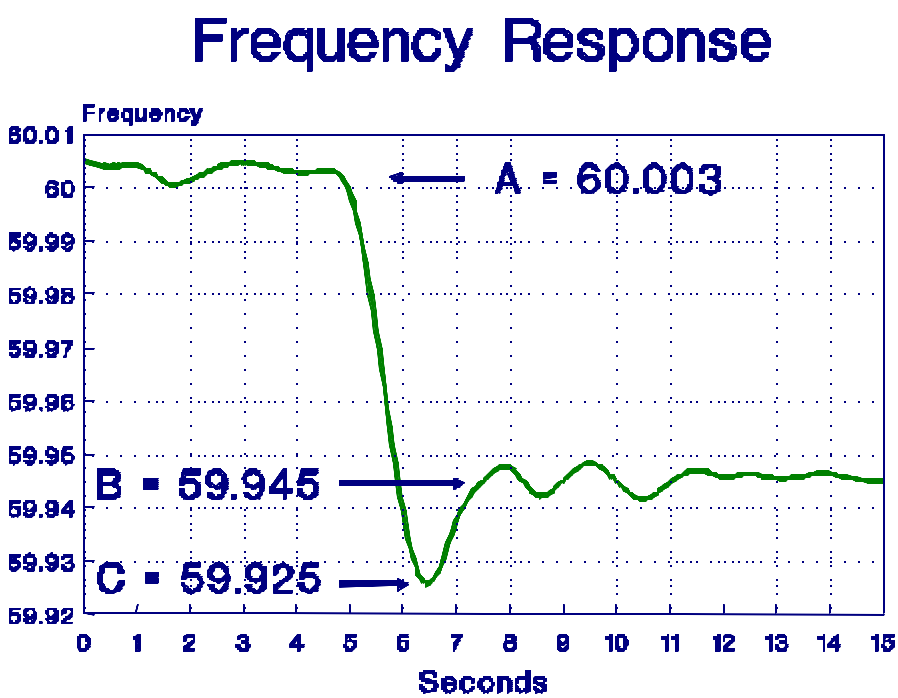



**Figure 1 Typical Frequency Excursion**

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, while point B is the settling frequency of the Interconnection's frequency.

There are two groups of "resources" that arrest a decline in frequency. They are discussed below.

# Understand and Calculate Frequency Response

## Load

The rate of frequency decline from points A to C is slowed by "load rejection." Motor load[i] in particular is affected by frequency. When frequency drops, the motors slow down and they produce less work and therefore consume less energy. If frequency drops by 1%, motor load will drop by 3%. Non-motor[ii] (resistive) load generally remains constant. The net of these is the general rule of thumb that a 1% change in frequency causes a 2% change in load (and vice versa).

In summer, systems tend to have a much larger proportion of motor load. This along with the greater numbers of generators in service to meet the higher demand means that Frequency Response is typically greater in summer.

## Generators

All generators have some type of governor control. The governor on a generator is basically identical to cruise control on an automobile. The governor senses a change in speed and allows more energy to be delivered to the generator's prime mover (more water in a hydro station, more steam to a turbine, more fuel to a combustion turbine).

Governor action halts the decline and causes the "knee" of the excursion and brings frequency back to point B.

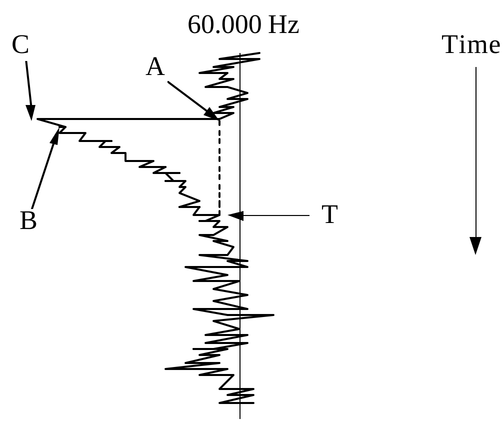



**Figure 2 - Typical Frequency Excursion (Longer Time Window)**

Figure 2 looks at the same disturbance over roughly 20 minutes. You can see a slight "snapback" in frequency from point C–B. This is due to the governor action of all the generators in an Interconnection. It is important to note that frequency will not recover from point B to 60 Hz until the contingent control area replaces the amount of lost generation. This means that the time from point A to point T gives a good approximation of the time it took the contingent control area to replace the energy from a lost generator. (This estimate of recovery time is actually conservative, for reasons we will discuss later.)

## Understand and Calculate Frequency Response

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

- −3300 MW / 0.1Hz (Eastern Interconnection)
- −600 MW /0.1 Hz (ERCOT)
- −1500 MW/0.1 Hz (Western Interconnection — WECC)

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:

- −0.03 Hz (Eastern Interconnection)
- −0.17 Hz (ERCOT)
- −0.07 Hz (WECC)

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

Note: The Frequency Response numbers above are based on a limited sampling of data. There is no process or common methodology in place to consistently quantify the responses of these Interconnections.

### Frequency Control

The energy used (by loads) must be equal to the energy provided (by generators) to maintain a steady frequency. Frequency is essentially the same throughout an Interconnection and is easy to measure.

Why do we control the frequency of the power system? Abnormal frequencies can damage power system equipment, especially steam turbines.

### Automatic Generation Control

Automatic Generation Control (AGC) provides the fine-tuning for system frequency. Each control area responds to a frequency deviation according to the natural response of its turbine governors and its load. When a control area has lost generation or load, the rest of the Interconnection provides immediate support for the frequency through governor action. If control areas set their AGC Bias close to their natural Frequency Response, only the contingent control area will see a change in its Area Control Error (ACE). The control area which lost the generation or load is responsible for taking action within 15 minutes to restore the frequency to normal by changing generation or interchange schedules through its AGC.

### Unit Governors

It was already mentioned that all generators have some type of governor, which is much like the cruise control on a car. There are a couple added features to a governor.

## Droop

Consider what would happen if two cars on cruise control were coupled via a chain to a heavy trailer. If the cruise controls (governors) weren't exactly identical, there would be instability in how they each carried load. Imagine a temporary excursion that would cause car A to attempt to speed up, as car A's cruise control increased fuel flow and subsequently caused car A to assume more load, car B would sense that it's share of the load had decreased and attempt to slow down and vice versa. There would be a constant racing and runback in the engines of both cars.

Now imagine if there was a feature added to the cruise control such that any change in speed and subsequent signal to the cruise control, would be weighted based on the car's engine capacity ("droop"). Example: If more load were added to the trailer, both car A and car B would assume more load; however, (because of this new droop feature) the subsequent signal from the cruise control (governor) would be biased based on the engine sizes of the two cars. Load changes could be more evenly shared between the cars.

The same is true for generators on the power system. When a generator synchronizes to the Interconnection, it couples itself to hundreds of other machines rotating at the same electrical speed. Because all generators have this "droop" feature added to their governor, they will all respond in proportion to their size whenever there is a disturbance or load-resource mismatch.

What actually controls governor response is the generator's "droop setting." This is the governor function that dictates the relationship between speed and power output. NERC Policy says all generators over 10 MW will have governors and that these governors are set to a 5% droop. That means the governor is set to respond through the full range of unit capability for a 5% (3 Hz) change in frequency. That is, for a unit operating at 60 Hz and no load, a 3 Hz drop in frequency would cause the governor to attempt to take the unit to full load. For smaller changes, it responds proportionately less, but always on the 5% droop curve.

> **Interesting Fact:**
> The Maritimes area sets their generation with a 4% droop because they occasionally island from the Eastern Interconnection. The smaller droop gives better frequency control when islanded.

Since frequency in the North American Interconnections only varies by a fraction of a Hertz, the swings in loading due to governor droop are generally small (unless the Interconnection were to break up into islands).

## Deadband

There is one additional feature displayed by governors called "deadband." Deadband is the amount of frequency change a governor must see before it starts to respond. Actually, deadband was a natural feature of the earliest governors caused by gear lash (looseness or slop in the gear mechanism). The deadband serves a useful purpose, preventing governors from continuously "hunting" as frequency varies ever so slightly.

## Understand and Calculate Frequency Response

NERC Operating Policy 1.C, "Frequency Response and Bias," Guide 3, "Governor droop," recommends a deadband ***not to exceed*** ± 0.036 Hz. That is, the governor should fully respond to frequency deviations greater than ± 0.036 Hz. They can (and should) respond to smaller deviations.

From a practical sense, if we are to measure the Frequency Response of all control areas, small excursions (significantly smaller than the maximum deadband) should not be included in the measurement.

# Frequency Bias and Frequency Response

The terms Frequency Response and Frequency Bias are used almost interchangeably. It is important to understand the difference between the two.

## Frequency Response

Frequency Response or Frequency Response Characteristic (FRC) is the change in frequency that occurs for a change in load-resource balance in an Interconnection.

In other words, if a generator of 1,000 MW is lost somewhere in an Interconnection, frequency will decline. The actual amount of decline will depend on the characteristics of the load (how much motor load) and the total governor response available at the time (the number of generators, their relative loading and their governor settings).

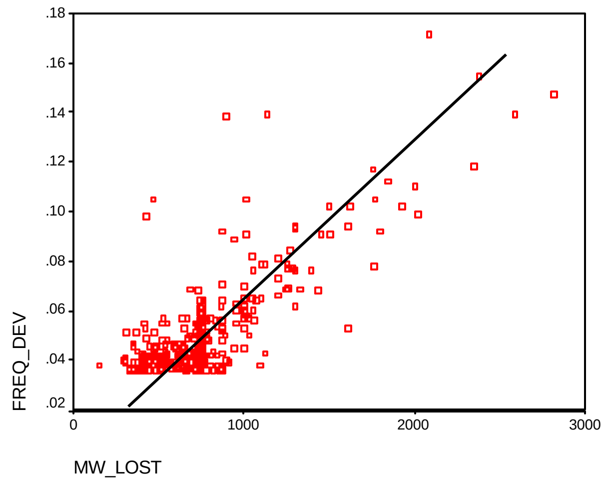



**Figure 3 - WECC Frequency Excursions vs. Generation Loss**

Figure 3 shows the observed frequency deviations observed in WECC for roughly 350 events between 1994 and 2002. The line represents the average frequency response of 1,500 MW/0.1 Hz. Events below the line imply a greater Beta[1] for the given event. Those above the line represent a smaller Beta.

[1] The mathematical terms for frequency response are Beta or ß (for an Interconnection) and beta (small letters) for a control area or generator.

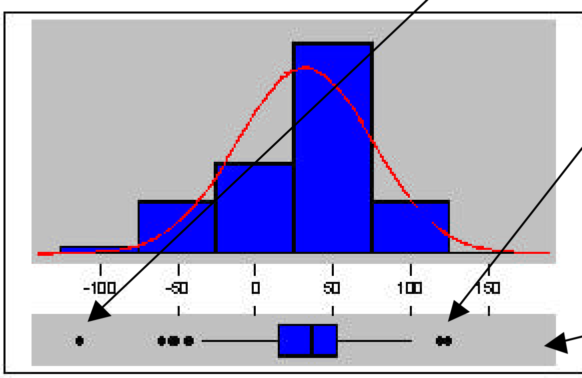
# Understand and Calculate Frequency Response

The total Frequency Response in an Interconnection is the sum of the responses from all control areas within the Interconnection.

## Frequency Response Variability

One of the issues regarding measuring Frequency Response is its variability at the control area level. There are very significant differences event-to-event. A small load swing within a control area can greatly change the resultant calculated response. This is why trying to estimate response from only a few events is a problem.

Figure 4 is a graph of summary data for a medium sized control area in the Eastern Interconnection. It represents the Frequency Response in MW/0.1 Hz for 64 frequency excursions over 11 months. The graph demonstrates the variability of observed Frequency Response. Even though the average response was around 35 MW/0.1 Hz, the performance for single events ranged from –114MW/0.1 Hz to 124 MW/0.1 Hz.




This diagram is often called a "box and whisker" graph. The blue box represents the range of the "middle 50%" of observed events. The average value is the black vertical line. The "whiskers" attached to the blue box represent the upper and lower "quartiles". The "dots" beyond the whiskers are "outliers" or rare events.

**Figure 4 - An Eastern Interconnection Control Area's Frequency Response**

Measuring the control area's compliance via a few events will not accurately reflect its actual performance. Because of the variability in responses, many events must be captured to give a valid representation of performance.

> **Important Note:**
> In this graph (as in most cases when people talk about Frequency Response), the numbers are plotted as positive values. "Normal" or expected Frequency Response is actually a negative value (as Frequency drops, Response increases, therefore a negative or inverse relationship). The same is true for Frequency Bias.

If a control area calculates its response from observed events, it should use the MEDIAN value of all the events during the rolling 12 months as the control area's response. The median value is the "middle" data point of all the observations. The median response for the data shown in Figure 4 is 37 MW/0.1 Hz. This is particularly important if the sample size is small.

## Frequency Bias

If you recall, FRC is the actual response provided by control areas for a particular set of events.

Control areas use Automatic Generator Control (AGC) systems to meet their minute-to-minute obligations to serve their internal load. If an excursion happens external to a control area, there should be an immediate outflow from the control area to arrest frequency decline. This outflow is from "load rejection" and governor response. Note: "Load Rejection" is not a defined term. It is intended to mean the load reduction following a frequency drop due to frequency-sensitive load.

In order to prevent AGC from "fighting" this natural frequency support, a term is added to the ACE equation. This Bias term is supposed to be a number that reflects the natural Frequency Response of the given control area. In other words, if there is an external excursion, there will be a natural outflow from each control area in the Interconnection, but if each control area has a Bias that reflects its natural response, the ACE for each control area should not change (due to the excursion) and the AGC of each will not fight Frequency Response.

If frequency remains low (the contingent control area does not recover its lost resource), the other control areas in the Interconnection will provide inadvertent interchange to hold frequency at a stable point. Since increased inadvertent contributes to reducing the frequency deviation, it is considered good inadvertent and is desirable.

**Quick Review:**

- Frequency Response Characteristic (FRC) is a measure of the natural change in frequency to a given mismatch in load and generation. The FRC for an Interconnection is typically termed Beta or ß, while the FRC for a control area is sometimes differentiated with a "small b" or beta.
- Frequency Bias (B) is a number a control area uses in its ACE equation that ideally reflects its natural response.
- Bias does interplay with AGC and CPS.

## Calculating Bias

NERC Policy 1 offers several possible ways to calculate frequency Bias. The simplest is to use the "1% of load method." In other words, if a control area has a projected peak for the upcoming year of 5,000 MW, it may use a value of –50MW/0.1 Hz as its Bias. In most cases, this 1% value is greater than the control area's natural response. This causes some "over-regulation" at a control area level, but is generally considered good for the Interconnection.

**Interesting Fact:** An overstated Bias value gives a control area slightly wider $L_{10}$ limits for CPS. Refer to the "CPS Overview" training document for an explanation of why this occurs.

A control area may also use "variable Bias" in its AGC. The intent is to do a better job of estimating natural response at any time and thereby "fine tune" AGC. According to Policy 1, the variable frequency Bias value shall be determined by analyzing Frequency Response as it varies with factors such as load, generation, governor characteristics, and frequency.

> **Interesting Fact:** In 1998, Eastern Interconnection peak load was about 536,000 MW. Observed Frequency Response is about –3,500 MW/0.1 Hz. This means Frequency Response was about 0.65% of peak load.

# Trend in Frequency Response

There is evidence that the Frequency Response of the Eastern Interconnection is declining. Similarly, the training references on the WECC web site note a decline of Frequency Response in the West. Analysis by the members of the NERC Resources Subcommittee and others show the Eastern Interconnection's Frequency Response has declined from about –3,750 MW/0.1Hz in 1994 to less than –3,200 MW/0.1Hz in 2002. Theoretically, response should be ***increasing*** as load levels, and therefore on-line generation, increase.

There are several logical thoughts on why response is declining. Among them are:

- Steam turbine-generators operating on "sliding pressure" control.
- Nuclear units removing droop settings to avoid power swings.
- The United States is becoming less of an industrial economy (proportionally fewer large motor loads).
- Variable speed drives on motors do not provide traditional load rejection.
- Particular combustion turbine generator designs that actually have a positive frequency characteristic (their output MWs go down when frequency drops). This occurs because when frequency drops, turbine and compressor speed drops, airflow decreases, with correspondingly less allowable combustion. The manufacturer intentionally reduces fuel input on a frequency drop to prevent overheating. This phenomenon reportedly contributed to a blackout in Malaysia in 1996.
- Generators having less inertia (less mass per MW of output).
- A reduction in spinning reserve requirements. Some areas have reduced their spinning reserve requirement below the traditional 50%. (Policy 1 allows control areas to carry less spinning reserve if they are DCS compliant.)

***Some*** decline in response is not a problem for the Interconnections. Our Interconnections are large enough that any single contingency should not cause a frequency excursion of a magnitude that would harm equipment or lose load. The issue is nobody is sure of the point where this will become a problem.

There is a concern among some people regarding this degradation in response. There are opinions on why it is declining. The problem is nobody knows if the decline is "across the board" or whether there are areas without any response. This is why there has been a proposal for a "Frequency Response Standard."

## Understand and Calculate Frequency Response

> **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.

### Future of Frequency Response and Policy 1

The NERC Control Performance Standard (CPS) is intended to measure long-term control. The Disturbance Control Standard (DCS) measures performance in the sub-hour range. If a Frequency Response Standard (FRS) were implemented, it would measure performance on a sub-minute level. These issues are being discussed in the new NERC standards process. (Refer to: http://www.nerc.com/standards/reliabilitystandards.html)

It is ***possible*** that Frequency Response may become a commodity. If one control area is short of response, it may be able to buy it from another. This would be something akin to an "emissions credit" type of market.

There has been debate whether Policy 1 should still address the need for governors. Those wanting to do away with the requirement note that they see no problem with the trend in response.

To date, Policy 1 addresses "system normal" conditions. Frequency Response is primarily a resource for disturbance conditions, particularly during islanding and black start. Governors need to be fully functional during these situations.

# Policy Discussion

This section is a summary of the various requirements regarding Frequency Response in NERC Policy 1.

### Calculating Response and Bias

Control areas calculate their Frequency Response and report their Bias by January 1 of each year. The primary purpose is to determine CPS $L_{10}$ limits. All reported Bias and $L_{10}$ limits can be found on the NERC Resources Subcommittee web page.

Bias settings can be changed whenever factors used to determine the current setting change.

Each control area shall report its Frequency Bias setting and method for determining that setting, to the Resources Subcommittee.

Each control area must be able to demonstrate and verify to the Resources Subcommittee that its Frequency Bias setting closely matches or is greater than its system response.

The Bias and the method used to determine the setting may be changed whenever any of the factors used to determine the current Bias value change. Examples would be the addition of a large generator into a small control area or the assumption of load responsibility (by merging control areas or through regulation services).

Control areas providing regulation services or using dynamic interchanges must properly take Frequency Response into account when calculating Bias:

1. If providing Overlap Regulation Service, incorporate all of the other CONTROL AREA'S tie lines, Frequency Response, and schedules into its own AGC/ACE equation.
2. Incorporate respective share of remote Jointly Owned Units (JOU) into the Bias calculation if control is dynamic, but not if done via a fixed schedule.
3. A CONTROL AREA that is performing OVERLAP REGULATION SERVICE will increase its FREQUENCY BIAS SETTING to match the Frequency Response of the entire area being controlled. A CONTROL AREA that is performing SUPPLEMENTAL REGULATION SERVICE shall not change its FREQUENCY BIAS SETTING.

NERC Appendix 1-H includes a requirement for a "tie deviation from schedule" chart for operators. The purpose of monitoring net tie deviation from schedule is to provide a measurable interchange response in MW for frequency excursions. This enables control areas to more accurately calculate frequency Bias values and comply with NERC Frequency Response surveys.

***Note***: This requirement was put into policy during the time when paper charts were the means for recording data for Frequency Response surveys. Although not stated in policy, the goal of this chart can be achieved by capturing digital data that can be scaled as needed.

## Governors

Policy 1 has several guides (good practices) regarding governors:

1. Generating units with nameplate ratings of 10 MW or greater should be equipped with governors operational for Frequency Response unless restricted by regulatory mandates.
2. Turbine governors and HVDC controls, where applicable, should be allowed to respond to system frequency deviation, unless there is a temporary operating problem.
3. All turbine generators equipped with governors should be capable of providing immediate and sustained response to abnormal frequency excursions. Governors should provide a 5% droop characteristic. Governors should, as a minimum, be fully responsive to frequency deviations exceeding ± 0.036 Hz.
4. Turbine control systems that provide adjustable limits to governor valve movement (valve position limit or equivalent) should not restrict travel more than necessary to coordinate boiler and turbine response characteristics.

## Reporting

Surveys are usually requested when a significant frequency deviation occurs to determine the Frequency Response characteristic of each control area. Procedures and forms are in the *Frequency Response Characteristic Survey Training Document*, which is located in the NERC Operating Manual.

In addition, the DCS Report has an entry field for large unit trips (1,000 MW). The intent of this data requirement is to catalog events that have an impact on Interconnection frequency. This is useful for benchmarking and tracking Interconnection Frequency Response (ß).

# Traditional Frequency Response Calculation

The NERC Resources Subcommittee occasionally requests Frequency Response Characteristic Surveys for specific events. Appendix 1 has a reporting form from the *Frequency Response Characteristic Survey Training Document.* The form is fairly self explanatory.

Control areas 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 the best indicator of central tendency when measuring a highly variable population like Frequency Response events.

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

So how have control areas obtained the observations to be used for calculating their Bias? There really has not been a standard way to do this. In some cases, control areas 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 1 - Frequency Response Calculator**

Table 1 demonstrates how a control area can go about calculating its Frequency Response from several events. The table is nothing more than a spreadsheet that takes Actual Net Interchange (ANI) and Frequency at points A and B and calculates both individual and cumulative Frequency Response.

Table 1 is 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 calculations, all you have to do is open the spreadsheet, then copy and paste it into a regular spreadsheet.

## Understand and Calculate Frequency Response

> **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 control area calculates its Frequency Response, it must make a decision on what Bias it will report to NERC by January 1 and use in its AGC. The following are the options to consider:

1. The best approach is to use a Bias that reflects natural Frequency Response for all the observed excursions.
2. If natural Frequency Response is less than 1% of projected peak load or generation, the 1% rule is generally the best path to take from a reliability perspective. Note: Previous versions of Policy 1 had a "1% minimum Bias requirement." The wording of the policy has changed and some people interpret its meaning such that the 1% is "one method among several" ways of calculating Bias. This is not the intent.
3. The Control Performance Standard does provide some incentive for control areas to select a Bias as part of a control strategy. For example, smaller control areas with "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 $L_{10}$ limits. (The size of CPS2's $L_{10}$ is related to Bias.)

Unless the process is automated, there is a fair amount of effort required in objectively calculating Frequency Response. The next section describes a new approach being tested by the NERC Resources Subcommittee.

# New Method for Calculating Frequency Response

### Background

The NERC Resources Subcommittee proposed a Frequency Response Standard in the fall of 2000. There was a great deal of support for such a standard. The issues revolved around how performance was to be measured and evaluated.

Calculating Frequency Response is not a new requirement. Many control areas do this in order to calculate their Bias. Those that do this manual task understand the challenges involved.

Figure 5 shows actual scan rate response for a medium-sized control area for five events in 1998. The chart is a graph of the control area'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.

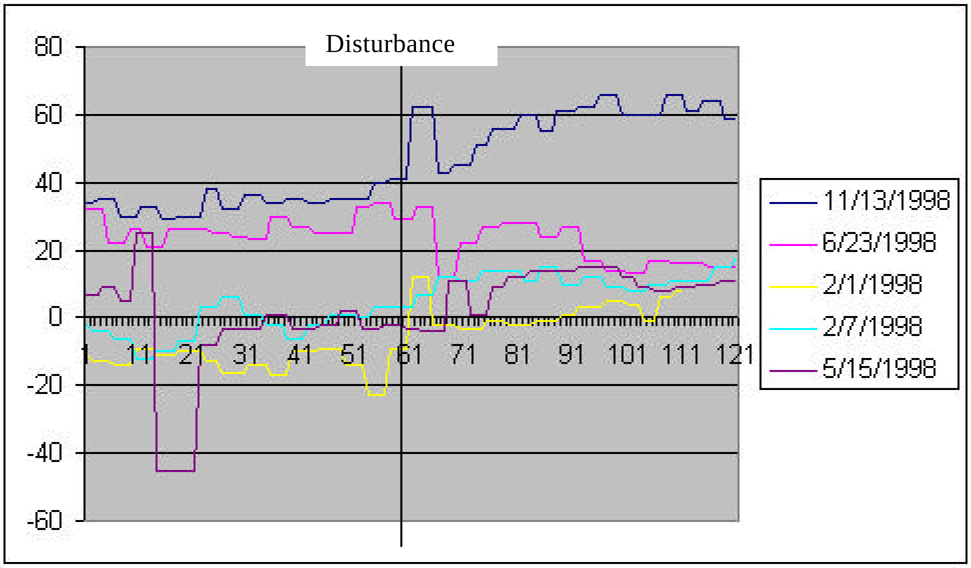



**Figure 5 - Frequency Response for 5 Events**

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 control area 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 control area 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 control area level, many events should be measured and a statistical average response calculated.

If enough events are captured, the effect of load variations will be cancelled (because load swings are equally likely to inflate or decrease the calculated Frequency Response).

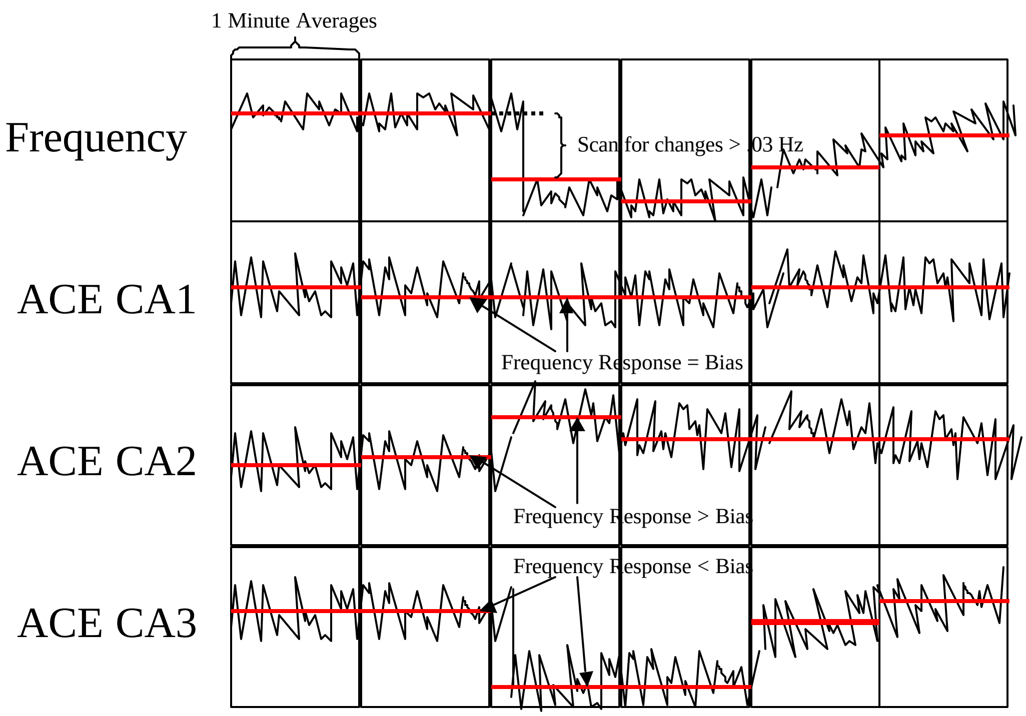
## Using CPS Source Data

As part of CPS, all control areas calculate and save one-minute averages of ACE and "frequency deviation from scheduled" (normally deviation from 60 Hz, except during time corrections). It is possible to do a calculation of Frequency Response from this one-minute data.

Figure 6 on the next page shows six minutes of ACE data for three control areas plotted against frequency. The black lines show the instantaneous values of frequency and ACE. The red lines represent the one-minute averages that would be calculated for CPS.

A formula that uses ACE and frequency deviation data to calculate response can be derived several different ways. The logic used to calculate response using this data is:

- If Frequency Response = Bias, the change in ACE pre- to post-disturbance is zero.
- A positive ACE swing on a disturbance implies a response greater than Bias.
- A negative ACE swing on a disturbance implies a response less than Bias.




Frequency Response = Bias - (delta ACE/10*delta f)

**Figure 6 - ACE and Frequency Data for three Control Areas**

# Understand and Calculate Frequency Response

In Figure 6, we see that control area 1 provided its Bias. Because control area 2's ACE swung positive, it contributed more Frequency Response than its Bias. Conversely, control area 3 contributed less Frequency Response than its Bias.

The formula for using CPS data is: **Frequency Response = Bias + (delta ACE/(10* delta f))**

Here is an example:

> Control area Bias = –60 MW/0.1 Hz
> Pre-disturbance (ACE = 20 MW, frequency = 60.01 Hz)
> Post-disturbance (ACE = 10 MW, frequency = 59.985 Hz)
> Response = –60 + (10/.25) = –60 + 40 = – 20 MW/0.1 Hz

We can see that from the example above, ACE swung toward the negative direction, which means the control area contributed less Frequency Response than its Bias. The results of this showed that Frequency Response for this event was –20 MW/0.1Hz. Is this a problem for this control area?

Recall that Frequency Response can vary significantly event-to-event. This is partly due to the resources on line at the time. The other issue is that load and generation are continuously changing naturally. This normal variation is mixed in with the Frequency Response that is provided by the control area. Let's look at some real data.

| Event | Date | Time | ACE | Freq Dev | Bias | Response |
|---|---|---|---|---|---|---|
| 1 | 6/1/2002 | 11:00 | –7.6 | 0.024 | –50 | |
| | | 11:01 | 4.6 | 0.055 | –50 | –10.65 |
| 2 | 6/9/2002 | 21:14 | –16.9 | 0.010 | –50 | |
| | | 21:15 | –4.7 | –0.021 | –50 | –89.36 |
| 3 | 6/9/2002 | 22:23 | 9.1 | 0.018 | –50 | |
| | | 22:24 | 9.8 | –0.013 | –50 | –52.26 |
| 4 | 6/10/2002 | 22:15 | –60.3 | 0.008 | –50 | |
| | | 22:16 | –72.0 | –0.024 | –50 | –13.44 |
| 5 | 6/13/2002 | 08:05 | -4.2 | 0.007 | –50 | |
| | | 08:06 | –13.7 | –0.024 | –50 | –19.36 |
| 6 | 6/13/2002 | 09:46 | –0.7 | –0.023 | –50 | |
| | | 09:47 | –20.8 | –0.058 | –50 | +7.43 |
| 7 | 6/16/2002 | 21:55 | 22.6 | 0.026 | –50 | |
| | | 21:56 | 16.9 | –0.008 | –50 | –33.24 |
| 8 | 6/16/2002 | 23:14 | 30.1 | 0.017 | –50 | |
| | | 23:15 | 22.2 | –0.014 | –50 | –24.52 |
| 9 | 6/22/2002 | 22:17 | 17.2 | 0.021 | –50 | |
| | | 22:18 | 9.1 | –0.012 | –50 | –25.46 |
| 10 | 6/27/2002 | 13:46 | 29.9 | –0.014 | –50 | |
| | | 13:47 | 36.6 | –0.049 | –50 | –69.14 |

**Table 2 - Frequency Responses for an Eastern Interconnection Control Area**

Table 2 is CPS source data for a medium sized control area in the Eastern Interconnection. All CPS one-minute average data was scanned for step changes in Frequency of 30 mHz or greater. Recall that the LARGEST deadband for governor response is 36 mHz. The size of excursion for which to scan is a tradeoff. Too small means governors may not be fully represented in the response. Too large may mean not enough samples are gathered for meaningful information. There are some interesting things to note in Table 2.

The first event (June 1) is for a step ***increase*** in frequency. Since it occurred at the top of the hour it is likely due to ramping in of schedules. Still, the governors and load do not care. Frequency Response will still occur. Note that this control area under-contributed for this event.

Event 6 is also interesting. The control area actually displayed a positive Frequency Response (it aggravated the frequency error). This is not unusual. Remember that normal load and generation swings are intermingled with Frequency Response. But the value of capturing many events is that the "true average" shows up by statistical evaluation of many events.

Figure 7 is a chart of the Frequency Response for this Eastern Interconnection control area for ten events in June 2002. The average response for these events was 33 MW/0.1 Hz, while the median response was 25 MW/0.1 Hz (actually –25 MW/0.1 Hz, but as noted earlier, Frequency Response is generally communicated as a positive value).

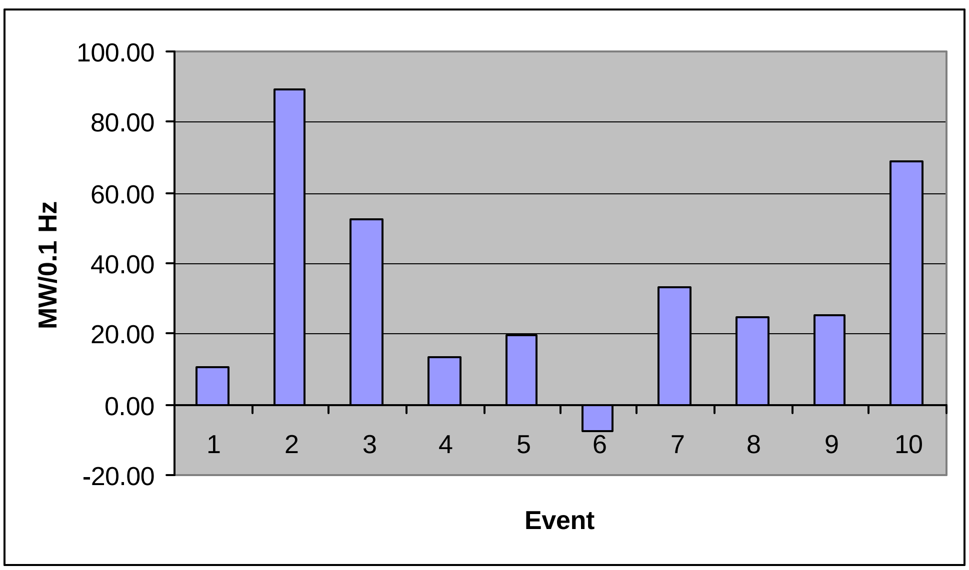



**Figure 7 - Chart of Frequency Responses to Events in Table 2**

What would have occurred if only one or two events were chosen through some random process? The answer, could vary anywhere between roughly zero and 80 MW/0.1 Hz depending on luck. However, if more months are included, the better the sample will reflect natural response for this control area.

## Understand and Calculate Frequency Response

Even though these calculations were made using CPS source data (one-minute averages of ACE and Frequency Deviation from Schedule), the answers are similar to the results that would have been achieved using scan-rate data. In fact, the answer may be better:

- There is significant variation in a single control area from event to event. This means that the selection process for events to be measured markedly affects the results. If every control area is not working off the same selection criteria or the same set of events, it is likely that results will be inconsistent.
- Some control areas calculate their response off 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.
- 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, the effects will be netted out over many events.

**ERCOT Note:** ERCOT operates as a "single control area" Interconnection. While it can use one-minute average data to assist in their Frequency Response calculation, their formula is different. Frequency Response for ERCOT would be:

**(Amount of generation lost in MW)/ (10*(Frequency Change in Hz))**

### Automatic Tool

The NERC Resources Subcommittee proposes using the one-minute CPS source data to calculate Frequency Response as described above. In fact, a member of the Resources Subcommittee has developed a tool to automatically calculate Frequency Response (along with many other useful features) as long as a control area saves its CPS source data in a common format. This free tool is available at: ftp://www.nerc.com/pub/sys/all_updl/oc/rs/cpscalc.xls

A tutorial for this tool (along with a set of data for testing) is also available. Contact your Resources Subcommittee representative for information.

# Summary

The following is a summary of the key points discussed in this training document. We recommend that you take the quiz at the end of this document before reviewing the summary. Refer to the summary in the future as a refresher.

# Understand and Calculate Frequency Response

- Frequency is the one value common throughout an Interconnection.
- If frequency is off schedule, load and generation are not in balance.
- Arresting frequency deviations is the job of ***all*** control areas.
- Frequency Response is the sum of a control area's natural load response to frequency and the governor response of generators within the control area.
- Frequency Response arrests a frequency decline, but does not bring it back to normal. Returning to scheduled frequency occurs when the contingent control area 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 governor response capabilities of their black start units.
- All control areas 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 (control area output increases as frequency declines) expressed in MW/0.1Hz.
- The typical (best) way to calculate Frequency Response is to observe the change in control area output for several (many) events over a year.
- A control area should set its Bias equal to its natural Frequency Response.
- The Eastern Interconnection has a Frequency Response of roughly 3,300 MW/0.1 Hz. This means the loss of a 1,000 MW generator will drop frequency roughly 0.03 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 control areas 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. They act to mitigate frequency change.
- AGC supplements governor control by also controlling tie flows and permitting scheduled interchange.
- ACE, the main input to AGC, requires frequency and schedule 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 control areas 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. There may be areas that cannot contribute to restoration.

# ACE Review

This section is intended to review the concept of Area Control Error (ACE). If you are familiar with this topic, you may proceed to the Review Questions.

NERC Policy 1 asks each control area to limit its effect on other control areas in its Interconnection. The measure of the effect on others is ACE. The equation for ACE is:

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

Where:

- $NI_A$ is Actual Net Interchange
- $NI_S$ is Scheduled Net Interchange
- B is control area Bias
- $F_A$ is Actual Frequency
- $F_S$ is Scheduled Frequency
- $I_{ME}$ is Interchange (tie line) Metering Error

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

The combination of the two ($NI_A - NI_S$) represents the ACE associated with meeting schedules 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 control area's obligation to support frequency. ß is the control area's frequency Bias stated in MW/0.1Hz (ß'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. If the"10B ($F_A - F_S$)" is used by itself for control, it is called "flat frequency" control.

$I_{ME}$ is a correction factor for meter error. The meters that measure instantaneous flow are not as accurate as the hourly meters on tie lines. Control areas are expected to check the error between the integrated instantaneous and the hourly meter readings. If there is a general error, a value should be added to the ACE calculation to compensate for instantaneous error. This value is $I_{ME}$. This term should normally be very small or zero.

Using a quick example. Assume a control area with a Bias of −50 is purchasing 300 MW. The actual flow into the control area is 310 MW. Frequency is 60.01 Hz. Assume no time correction or metering error.

$$ACE = (-310 + 300) - (10^* (-50)(60.01 - 60.00) = (-10 +5) = -5 \text{ MW}$$

The control area should be generating 5 MW more to meet its obligation to the Interconnection.

# Review Questions

1) System frequency:
   a) Measures load-resource balance in an Interconnection or island
   b) Changes in direct relation to generator voltage
   c) Varies from control area to control area
   d) All of the above

2) How does a control area 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 $L_{10}$ limit
   c) Measure the actual response to several frequency deviations
   d) None of the above

3) Generation external to your control area 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 control area is 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 control area that serves load is:
   a) 1% of the annual peak demand per 0.1 Hz change
   b) 2% 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 control area that does not serve native load is:
   a) 1% of the estimated maximum generation level for the upcoming year per 0.1 Hz change
   b) 2% 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 control area'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 control area 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) None 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 control area 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 control area 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 control area must incorporate the frequency Bias setting of the control area 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 control area, the providing control area uses only its own frequency Bias setting in its ACE equation. It does not incorporate the frequency Bias of the control area 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) An 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 control area 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 control area 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 control area 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

**Answer Key:** 1- a, 2-c, 3-b, 4-d, 5-a, 6-a, 7-c, 8-a, 9-d, 10-b, 11-c, 12-b, 13- c, 14- d, 15-a, 16- b, 17- b, 18-d, 19-c, 20-b, 21-d,

# Acronyms, Terms and Definitions

**Area Control Error (ACE)** – ACE is the algebraic sum of the net scheduled and net actual interchange and the Biased scheduled and actual system frequency. This parameter is used to determine a control area's control performance with respects to its impact on system frequency.

**Automatic Generation Control (AGC)** – Equipment that automatically adjusts a control area's generation to maintain its interchange schedule plus its share of frequency regulation. (See various AGC Control Modes.)

**Bias** – A term in the ACE equation that defines a control area's obligation to assist in frequency support of the Interconnection.

**Deadband** – The allowable change in frequency before a governor responds.

**ERCOT – Electric Reliability Council of Texas:** One of the ten NERC regional coordinating councils.

**Frequency Response Characteristic (FRC)** – For any change in generation/load balance in an Interconnection, a frequency change occurs. FRC is how any system (control area) responds to this change during any imbalance resulting from a sudden loss of load or generation. System frequency does not return to its pre-disturbance level until the control area experiencing the imbalance corrects its imbalance.

**Federal Energy Regulatory Commission (FERC)**: FERC is an independent regulatory agency within the Department of Energy (DOE), which regulates transmission and wholesale sales of electricity in interstate commerce.

**Governor** – A device in an electric power-generating unit that controls the MW output. Good interconnection practices expect the governor to be able to respond in a fashion to arrest frequency decline.

**$L_{10}$ – L sub-ten**: The bandwidth that ACE is bound to comply with CPS2. An ACE value (+/–) whose width is proportional to a control area's size.

**Regulation and Frequency Response Service (FERC Definition)** – An ancillary service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at 60 cycles per second (60 Hz). Regulation and Frequency Response Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) as necessary to follow the moment-by-moment changes in load.

**Tie Line Bias Control** – A mode of operation under AGC in which the area control error (ACE) is determined by the actual net interchange minus the Biased scheduled net interchange.

# Appendix 1 - Sample FRC Survey Form

**North American Electric Reliability Council**
**Frequency Response Characteristic Survey**

**Form FRC 1**

| | | | |
|---|---|---|---|
| **1. Date** | **Hr. Ending** | **(CST/CDT):** | **Control Area:** |
| | | | **Region:** |

**AREA FREQUENCY RESPONSE CALCULATION**

| | | |
|---|---|---|
| **2: Actual Net Interchange Immediately Before Disturbance (Point A)*** | | **MW** |
| **3: Actual Net Interchange Immediately After Disturbance (Point B)*** | | **MW** |
| **4: Change in Net Interchange** | | **MW Line 3 - Line 2** |
| **5: Load (+) or Generation (?) Lost Causing the Disturbance** | | **MW** |
| **6. Control Area Response** | | **MW Line 4 - Line 5** |
| **7. Change in Interconnection Frequency from Point A to Point B** | | **Hz (-) for frequency decrease; (+) for frequency increase** |
| **8. Frequency Response Characteristic** | | **MW/0.1 Hz Line 6 /(Line 7 x 10.0)** |

**OTHER INFORMATION**

| | | | | |
|---|---|---|---|---|
| **9. Frequency Bias Setting** | | | | **MW/0.1 Hz** |
| **10. Net System Demand Immediately Before Disturbance (Point A)** | | | | **MW** |
| **11. Synchronized Capacity Immediately Before Disturbance (Point A)** | | | | **MW** |
| **12.** | **From your charts** | **Frequency at Point A** | | **Hz** |
| **13.** | | **Frequency at Point B** | | **Hz** |
| **14.** | | **Frequency at Point C** | | **Hz** |

Notes:

Net power delivered *out* of a Control Area (over-generation) is positive (+).
Net power received *into* a Control Area (under-generation) is negative (–).

*Control Areas that have a Net Tie Deviation From Schedule Recorder should obtain these values from that device.

[i] Motor load makes up a large portion of a utility's total load, typically 40 to 60%. When we refer to motor load, we generally mean induction motors.
[ii] Non-motor loads, such as heaters, light bulbs, and electronic equipment, will vary in magnitude (MW) depending on voltage and frequency of the power system to which it is connected. Non-motor load is more depended on voltage than on frequency.