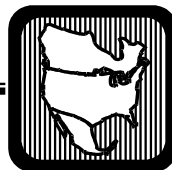


FREQUENCY-ACE DATA ANALYSIS STUDY

August 14, 2003 Blackout Investigation Report



North American Electric Reliability Council

March 4, 2004

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Executive Summary

The Frequency-ACE Investigation Team's (FAIT) initial analysis concluded that pre-disturbance abnormal frequency and area control error (ACE) events were not a direct root cause for the August 14, 2003 blackout. The Eastern Interconnection pre-disturbance frequency did not violate existing frequency-related NERC performance policies.

Further analysis conducted independently by Gary Bullock from the Tennessee Valley Authority (TVA) and by FAIT using frequency spectrum analysis confirmed the initial conclusion: pre-disturbance frequency behavior was not a direct root cause of the blackout on August 14.

OSIsoft's comments for the blackout investigation interim report, summarized in their report entitled *Comments on the DOE Blackout Report* by Dr. Wells and Mr. Russo, claim that before the disturbance on August 14, "significant power oscillations" occurred in the Interconnection. The FAIT initial frequency analysis and the two frequency spectrum analyses conducted independently by Mr. Bullock and by FAIT have not confirmed OSIsoft's claim of abnormal, significant frequency oscillations before the disturbance. FAIT and Mr. Bullock's studies detected frequency error oscillations similar to the ones identified in the OSIsoft report, but they were not considered abnormal or significant. Frequency oscillations similar to those that occurred on August 14 were observed for other days in August using the same frequency spectrum analysis techniques.

Purpose: The purpose and scope for FAIT was to analyze potential Eastern Interconnection frequency and ACE anomalies that may have occurred on August 14 and contributed to the blackout. The team's primary activity included comparing the August 14 ACE-frequency data to typical Eastern Interconnection data. The secondary activity was to determine if there were any unusual issues with the Eastern Interconnection's ACE-frequency control performance and the causal effects they may have had in the cascading failure and system collapse. The pre-disturbance, load-generation control behavior could have been a contributing factor in the creation of unscheduled flows between control areas.

ACE-Frequency Control: Control areas have the responsibility to maintain a continuous balance between their local generation and varying load, and they share the responsibility to maintain interconnection frequency and not to cause a burden on adjacent control areas. Control areas calculate a value called ACE that represents how closely they are meeting their balancing responsibilities. If there is a large ACE value in the same direction as the frequency deviation, the control area is contributing to the problem, which translates into unscheduled flows on interconnected transmission systems. Analysis of a control area's ACE and its impact on Interconnection frequency helps determine the adequacy of the load-resources balance at both the local and Interconnection levels and the potential impacts of any imbalance.

Data: FAIT collected and validated Eastern Interconnection ACE and frequency data to establish a common database and conducted additional ACE-frequency analysis to evaluate the potential effects of the abnormal frequency events, including unscheduled flows between control areas.

Approach: FAIT identified and analyzed various pre-disturbance frequency and ACE anomalies using three methodologies:

1. Identify pre-disturbance frequency excursions originated by generator outages and analyze frequency response adequacy from the generator's governor response and its potential impact on the disturbance.
2. Define extended ACE and frequency anomalies and determine causes and whether those might contribute to the power system blackout.
3. Apply the Fast Fourier Transform (FFT) to determine whether the Interconnection frequency spectrum showed any other frequency abnormalities that could not have been identified with the first two methodologies, but that could have contributed to the power system blackout.

The results of the three analyses point to the same conclusion: the frequency behavior before the disturbance on August 14 was neither unusual nor significant; even if there were unusual frequency excursions, this pre-disturbance behavior was not a root cause of the blackout.

Recommendations: FAIT offers the following six recommendations:

1. Frequency and ACE Data Quality and Completeness for Control and Compliance

- a. NERC should improve data quality. Missing or inadequate data storage and time stamping hampered FAIT's analysis. This inadequacy includes the area interchange error (AIE) surveys. Also, a high degree of uncertainty exists about the timing of the generating unit trips from the collected data and thus the calculated Eastern Interconnection frequency responses. It is unclear what other events may have occurred in the Interconnection that could have masked or modified the observed behavior. FAIT recommends that NERC or the U.S. Department of Energy (DOE) expedite industry efforts to develop a standard (or standards) for:
 - i) Time stamping original field data, including generator events, based on a North American time standard (GPS, IRIG, or Zulu).
 - ii) Collecting generator outage data (time, MW, ramp rate, and location) and routinely analyzing impacts on interconnection frequency.
- b. NERC should approve and implement the proposed frequency data analysis and storage project.

2. Automatic Generation Control (AGC) and Energy Management Systems (EMS) Surveys

- a. NERC should perform a control area survey for AGC, supervisory control and data acquisition (SCADA), and emergency management system (EMS) backup systems (analog or digital) availability and control functionality. An assessment survey would result in recommendations if required. Backup AGC should be available as a hot standby and provide indication to dispatchers on readiness to assume control. As a minimum, backup AGC should compute ACE for comparison to the primary AGC.

3. Review Reliability Coordinators' Responsibilities

- a. NERC should review, define, and audit reliability coordinator responsibilities.
- b. Questions have been raised about current control performance criteria for situations where interconnection frequency remains continuously above or below the scheduled frequency for long periods of time as happened on August 13 for almost eight hours and

on August 14 for more than three hours. Operating Policy 9 requests reliability coordinators to take remedial action when the interconnection frequency error is “in excess of 0.030 Hz for more than 30 minutes.” Several issues have been raised: is 0.030 Hz the correct threshold for all interconnections? What reliability performance is Operating Policy 9 attempting to address, and when should the 30-minute count start and end?

4. Wide-Area, Real-Time Monitoring Tools

- a. NERC should improve current tools used by reliability coordinators for the real-time monitoring of ACE and frequency to conform to requirements identified during this investigation.
- b. NERC should tune up reliability coordinator monitoring and alarm tools such as “delta flow” to flag unexplained delta frequency.
- c. NERC should investigate the use of additional real-time control monitoring tools to help operators identify abnormal and unexpected operating conditions.

5. Wide-Area Operations Training

- a. NERC should launch a major effort including short and long-term plans for training reliability coordinators and security personnel in the use and analysis of wide-area operational data and actions to take during emergency operational conditions.
- b. NERC should develop training programs and documents to assist reliability coordinators in identifying and tracking frequency problems experienced by control areas in meeting their balancing obligations.

6. Investigation Issues to Pass to NERC Resources Subcommittee (RS) for Further Investigation and Action

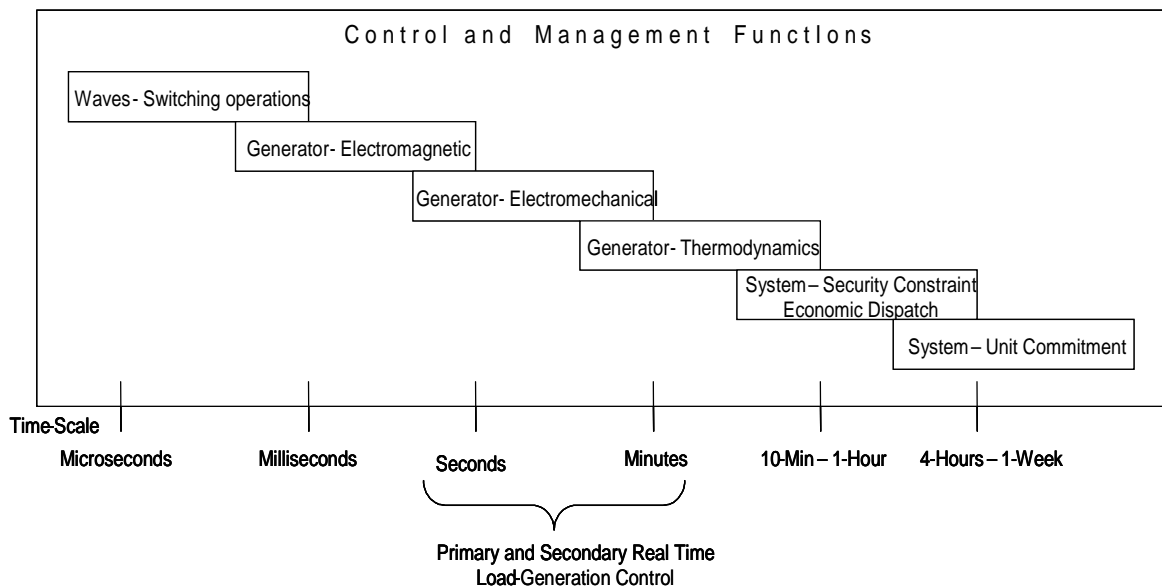
- a. NERC should request an explanation of differences between AIE schedules and Interchange Distribution Calculator (IDC) schedules and any impact on voltages in Ohio.
- b. NERC should publish a list of control areas that do not provide real-time data
- c. NERC should investigate the collection of real-time net actual and scheduled interchange with adjacent control areas. This will help identify “unexplained ACE” and allow an ACE calculation for each control area when their EMS is down (via a calculation using neighbors’ data).
- d. NERC should expedite control area transfer of data for the NERC AIE Real-Time Monitoring application.
- e. NERC should require all control areas to report ACE to enable NERC to have complete data records.
- f. NERC should identify reports and assess control areas that experienced EMS-AGC data problems on August 14, 2003.
- g. The RS should develop ways to validate that the interconnection ACE
 - i) Compares to $\sum ACE_{CA}$
 - ii) Compares to Interconnection frequency

1. Introduction and Background

The Frequency-ACE Investigation Team (FAIT) was established to analyze potential Eastern Interconnection frequency and ACE anomalies that may have occurred on August 14, 2003. The primary purpose was to compare the August 14 ACE-frequency data to typical interconnection data, and second to determine if there were any unusual issues with Eastern Interconnection operational ACE-frequency control performance and the effects they may have had related to the cascading failure and system collapse. This introduction and the next two sections describe the general technical background, the methodologies used to conduct the analyses, and how the pre-disturbance frequency behavior compared with its behavior for other days in August. The remaining sections of this report describe the results for each of the abnormal frequencies analyzed, with the last section summarizing recommended areas for improvement.

The overall management and real-time control of a power system is a complex, hierarchical process requiring interaction between the different hierarchical levels within widely different time scales. The figure below shows the main elements of the control hierarchy, the approximate time scale on which each level operates, the two levels where the primary and secondary frequency control operates, and the focus for FAIT analysis.

Figure 1.1 — Power System Control Hierarchy



Power system frequency control is required to maintain a continuous balance between generation resources and a varying load demand; while system frequency, voltage levels, and a security-constrained economic dispatch are also maintained. Primary frequency control, coming from the generators' turbine governing systems, operates during the first one-to-two seconds of a load-resource imbalance. Primary control is decentralized because it is installed in power plants situated at different geographical locations. Interconnection frequency control and tie-line control constitute secondary control, operate with periodicities from two-to-eight seconds, and are normally implemented in a central computer.

In North America, multiple control areas, in addition to maintaining a continuous balance between their local generation and varying load, share the responsibility to maintain interconnection frequency and not burden other control areas. Control areas calculate a value called ACE¹ that represents how closely they are meeting those responsibilities. If there is a large value of ACE in the same direction as frequency, the control area is contributing to frequency deviation and creating unscheduled flows on other control areas' transmission systems. Analysis of control area ACE and its impact on interconnection frequency helps determine the adequacy of the load-resources balance at both the local and interconnection levels and the potential impacts of any imbalance.

Most electricity in the world is provided using alternating current. In North America, the frequency of the alternating current is (nominally) 60 cycles per second or 60 Hertz (Hz). Electric system operators and real-time load-resources controls (in each interconnection) work together through control areas to keep the interconnection frequency close to 60 Hz.

Potentially, high or low interconnection frequency may cause or contribute to system failures. For example, predetermined high and low frequencies could trigger generator protection systems that could automatically separate the generators from the system. Activated protection systems may aggravate the situation and create new problems such as additional frequency excursions, overloads, voltage problems, and load shedding. NERC Operating Policy 5 regulates control area emergency operations including their response to abnormal frequencies.

Ineffective generation and load following control, mismatches between scheduled and actual interchange, metering errors, and scheduling errors all contribute to actual interconnection frequency deviation from scheduled interconnection frequency. In turn, this deviation is the basis for the accumulation of interconnection time error. Generation-load mismatches often manifest themselves as local transmission problems (e.g., as a result of over- or under-generation or generator tripping) rather than being distributed all over the system. Longer-term frequency deviations imply significantly greater unscheduled flows.

For frequency assessment purposes, FAIT assumed that the Eastern Interconnection frequency declines or increases resulted from a mismatch between generation and load on the order of 3,200 MW per 0.1 Hz. In other words, a difference of 1,000 MW in the load-resources balance would cause a frequency change on the order of +/- 0.031 Hz.

¹ The control equation for ACE is: $ACE = (NIA - NIS) - 10\beta (FA - FS) - IME$. In this equation, NIA accounts for all actual meter points that define the boundary of the control area and is the algebraic sum of flows on all tie lines. Likewise, NIS accounts for all scheduled tie flows of the control area. The combination of the two (NIA - NIS) represents the ACE associated with meeting schedules and, if used by itself for control, would be referred to as flat tie-line regulation. The second part of the equation, $10\beta (FA - FS)$, is a function of frequency. The 10β represents a control area frequency bias (β 's sign is negative) where β is the actual frequency bias setting (MW/0.1 Hz) used by the control area and 10 converts the frequency setting to MW/Hz. FA is the actual frequency and FS is the scheduled frequency. FS is normally 60 Hz but may be offset to effect manual time error corrections. IME is the meter error recognized as being the difference between the integrated hourly average of the net tie line instantaneous interchange MW (NIA) and the hourly net interchange demand measurement (MWh). This number should normally be very small or zero.

The risks and impact to the bulk power system associated with abnormal frequency excursions depend on the magnitude, duration, and number of control areas causing the abnormality. One impact of abnormal frequencies is unscheduled flows across intermediate control areas caused by abnormal load-resources balance.

It has been estimated that for the Eastern Interconnection, a short-duration frequency deviation of 0.060 Hz could originate an unscheduled flow of about $0.6 \times 3,200 = 1,920$ MW and rise to $0.6 \times 6,250 = 3,720$ MW in a long time frame under AGC action (assuming the sum of the AGC frequency biases for the Eastern Interconnection is 6,250 MW/0.1 Hz). A second risk and potential impact is that control areas approach their thresholds for automatic under-frequency load and generation shedding. For the Florida Reliability Coordinating Council (FRCC), the load shedding frequency threshold is 59.82 Hz. The rate of frequency change (dF/dT) is equal to generation minus load plus losses divided by the frequency response of the interconnection, Beta: $dF/dT = [\text{Generation} - (\text{Load} + \text{Losses})/\text{Beta}]$. This equation shows that the balance is maintained by changes in system frequency. It works by adding or removing energy from the storage reservoir provided by the inertia of the rotating equipment and inductive fields of the equipment attached to the system. The energy storage for rotating equipment is proportional to frequency squared.

The projected 2004 peak load for the Eastern Interconnection is roughly 607,000 MW in the summer and 536,000 MW in the winter.² There is no direct connection between total load and the frequency response of the interconnection; however, the set of units on line to serve the load and the composition of the load itself do have direct impacts upon the frequency response, as does the reserve margin between available generating capacity and load. The frequency response (the causal relationship between the loss of load and the expected frequency change) is a function of generator governor response and load frequency response.

Generator governor response is a function of the number and type of generators on line and the reserve margin maintained by these generators. Most generators in North America have governors with a 5 percent droop, that is, a 5 percent change in frequency (3 Hz under normal conditions) will cause a 100 percent change in power output, if it is available. The reserve margin of the generator determines how much actual governor response is available; a generator that is fully loaded (zero reserve margin) will not have any capacity left to provide governor response. In addition, some generators have limited or zero governor response due to regulatory or environmental reasons (i.e., nuclear units generally provide little or no governor response).

Load frequency response is provided by rotating and inductive loads connected to the interconnection. As frequency goes down, the power it takes to run inductive equipment drops. For rotating equipment, this drop is generally proportional to the square of the frequency change. Thus, as the nature of the load on the interconnection changes, the load frequency response changes.

The minimum load on the Eastern Interconnection may vary by up to 50 percent between peak and valley periods, both seasonally and daily. This fluctuation can have major implications for the number and type of generators and the type of load on the interconnection, but these factors

² NERC 2003 *Long-Term Reliability Assessment*

tend to offset each other, at least to some degree. For instance, during peak load periods, more generators are on line and capable of providing governor response, but they tend to be more heavily loaded and have less reserve margin than is available from the generators on line during valley (light load) periods. The nature of the load also tends to shift between peak and valley, with more inductive load generally on line during the peak than during the valley. Although these variations have been observed by numerous power system operators and engineers over the years, they have not been well characterized and no definitive studies are known to be available.

2. Analysis Methodologies Used to Identify and Analyze Frequency Anomalies

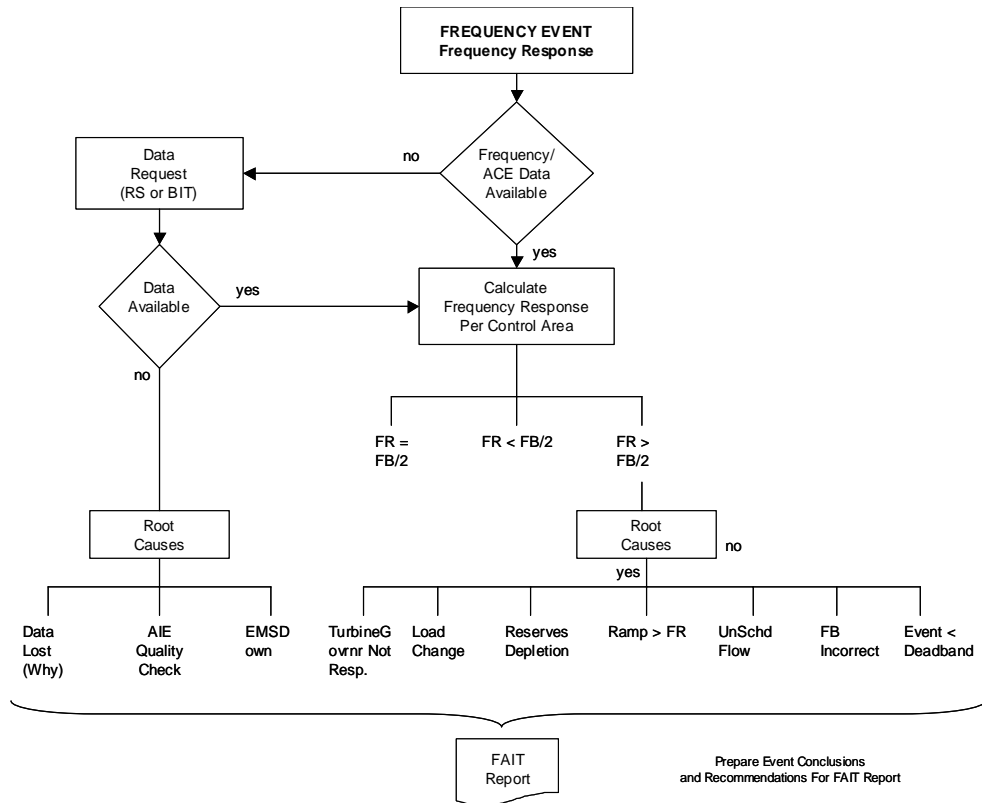
FAIT's frequency assessment methodology divided frequency anomalies into two categories: 1) frequency response at the generator-governor response level; and 2) extended frequency at the AGC level or beyond.

To identify frequency response anomalies, the first step was to collect and validate Eastern Interconnection frequency data. The second step was to scan the data for changes in frequency of 0.0125 Hz over a 12 second period. The resulting frequency events with a load-resources unbalance of $0.125 \times 3,200 = 400$ MW assumed an interconnection-wide frequency response of $3,200 \text{ MW} / 0.1 \text{ Hz}$. The frequency response abnormalities indicate mismatches between generation and load for different reasons including generator trips and load drops. These events may or may not be reflected in the Blackout Investigation Sequence of Events (e.g., they may have taken place in control areas not covered by the sequence of events summary).

Of particular interest to FAIT were the frequency anomalies not captured in the official sequence of events. Extended frequency anomalies were selected if the plotted frequency differential data showed extreme trends and stayed on one side of scheduled frequency for more than 30 minutes.

FAIT reviewed and defined two methodologies to identify and analyze the two types of frequency abnormalities. Later in the investigation, FAIT used the approach recommended by Dr. Wells and Mr. Russo from OSIsoft in their comment on the DOE blackout report to analyze the interconnection frequency variations using the Fast Fourier Transform (FFT). Figure 2.1 shows the process FAIT used to identify and analyze frequency response anomalies.

Figure 2.1 — Frequency Response Anomalies Analysis Process



The process began by identifying frequency ACE data availability. If data were available, the frequency response was calculated for each control area. Then possible root causes for anomalies were identified as shown in Figure 2.1. If, at the beginning of the process, no data were available, data were requested via the RS or Blackout Investigation Team (BIT) groups, and the process continued as before. If no data became available, possible root causes for missing data were identified. After completing the analysis for the seven frequency response anomalies, the root causes, conclusions, and recommendations were incorporated into the FAIT report.

Figure 2.2 reflects the process FAIT used to analyze extended frequency abnormalities. This process began by replacing and/or purging known bad one-minute ACE data. If net of “good” ACE explained the frequency error, then control areas and possible root causes were identified. If net of “good” ACE did not explain frequency error, the AIE ten-minute hour data was reviewed for “others” to identify possible causes. If the cause was identified, then root causes were investigated. If the cause was not identified, then the hourly AIE was checked to see if it implied a possible cause. If not, data was requested and control areas were identified to look for possible root causes. If hourly AIE implied a possible cause, control areas were asked to explain the AIE-ACE difference and provide an ACE estimate. Then, possible root causes were identified. After completing the analysis for the seven frequency response anomalies, FAIT members noted any inability to find cause, analyzed unscheduled flow impact, and asked for

explanations. Then, root causes, conclusions, and recommendations were incorporated into the FAIT report.

Figure 2.2 — Extended Frequency Anomalies Analysis Process

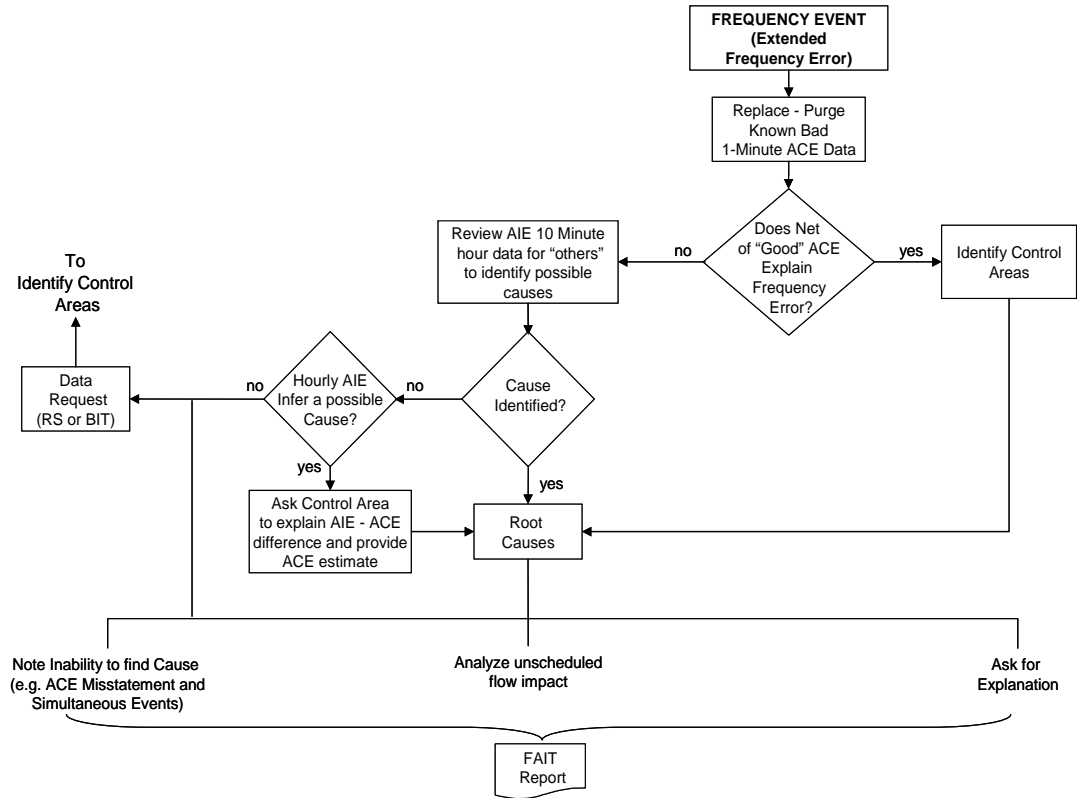
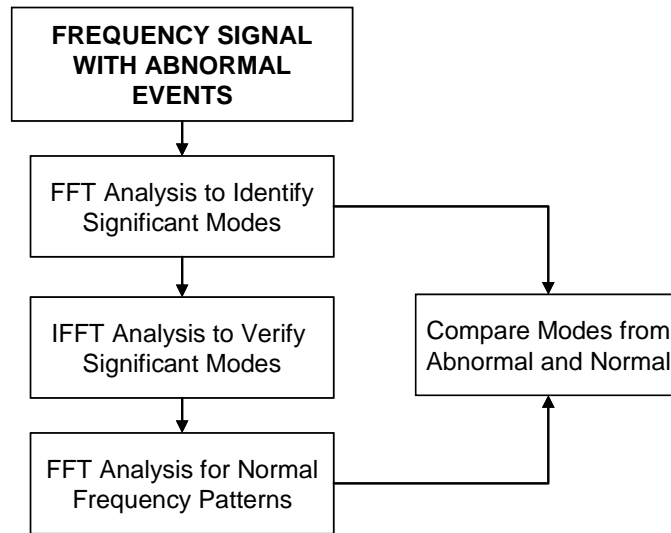


Figure 2.3 shows the FAIT process used for frequency spectrum analysis using FFT.^{3,4} The first step is an FFT analysis of the abnormal frequency signal to identify its significant modes, followed by an inverse FFT analysis to verify that the modes identified in Step 1 are really the significant modes. Spectrum analysis is also done for equivalent frequency signals for similar operational days to compare with the spectrum of the abnormal frequency patterns.

³ OSISO used FFT to base their comments on the blackout investigation interim report.

⁴ Gary Bullock from TVA also used FFT for his independent frequency analysis. His report has been included in this report as Attachment A with permission from the author.

Figure 2.3 — Frequency Spectrum Analysis Process Using FFT



3. Frequency Anomalies Identified from 0800 to 1600 EDT on August 14

Figure 3.1 depicts the chronology and magnitude of the frequency anomalies identified for August 14, 2003 from 0800 EDT until the system failed, together with the scheduled frequencies including a 59.98 Hz correction (started at 1200 EDT) implemented by a Time Error Correction (TEC). Tables 3.1 and 3.2 identify the specific data for each of the seven frequency response and three extended frequency anomalies.⁵

⁵ TECs are used to ensure that any equipment that use 60 Hz as a time standard are kept timely. TECs are done to keep electric clocks utilizing the frequency of the Eastern Interconnection as a time standard, accurate to within plus or minus ten seconds. See *NERC Operating Policy Manual, Appendix 1D – Time Error Correction Procedures*.

Figure 3.1 — Eastern Interconnection Frequency Anomalies Identified on August 14 from 0800 to 1610 EDT

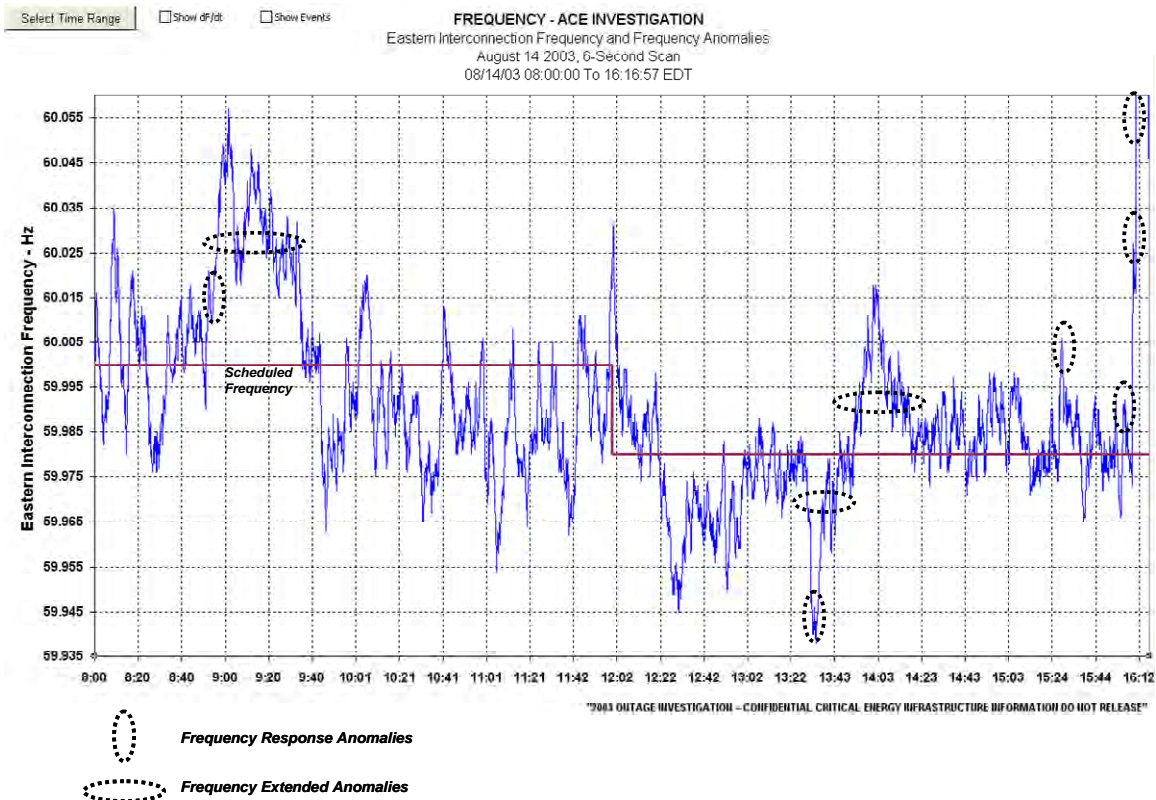


Table 3.1 — Eastern Interconnection Frequency Response Anomalies from 0800–1610 EDT on August 14, 2003

Time EDT	Frequency (Hz)	Anomaly (Hz)	Load-Resources Unbalance MW
0851:36	60.007	-0.0170	-544
1331:59	59.947	0.0170	544
1332:06	59.949	0.0160	512
1527:12	59.993	-0.0140	-448
1606:14	59.999	-0.0260	-832
1609:40	60.024	-0.0490	-1568
1609:42	60.025	-0.0260	-832

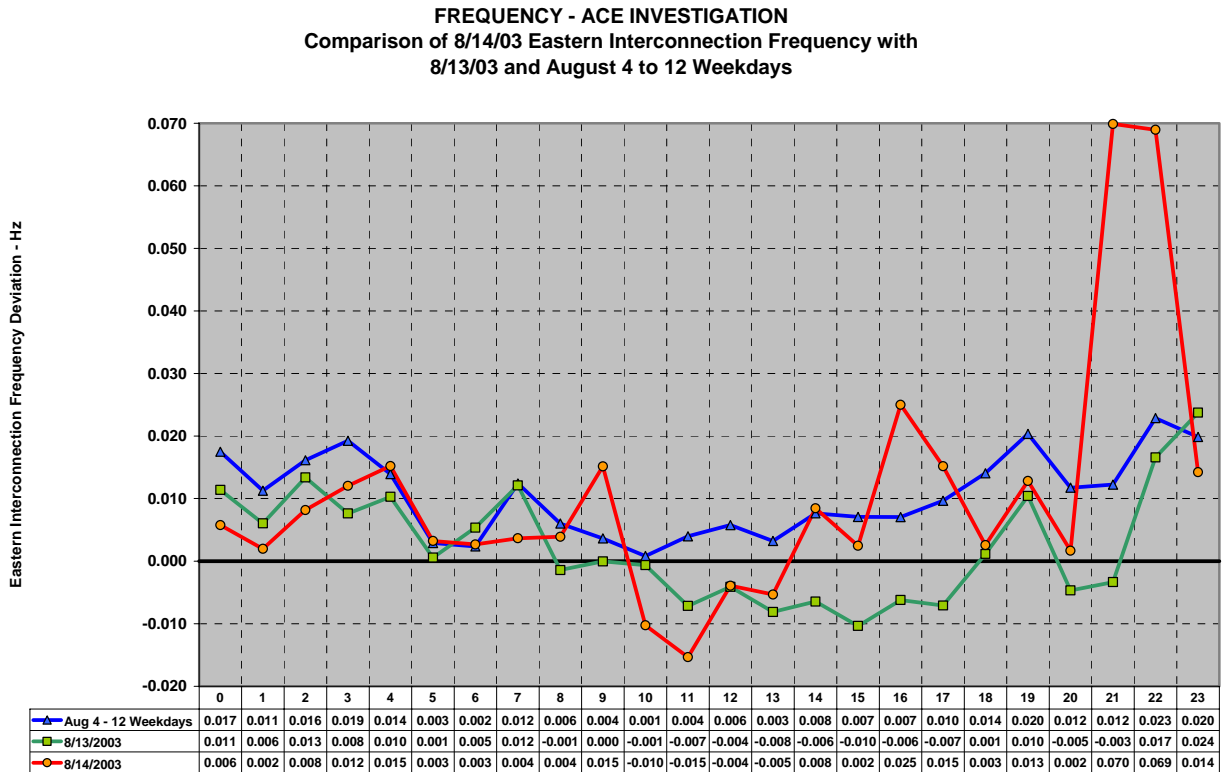
Table 3.2 — Eastern Interconnection Extended Frequency Anomalies from 0800–1610 on August 14, 2003

Time EDT	Highest Frequency (Hz)
09:00–10:00	60.057
13:30–13:40	59.938
13:50–14:10	60.018

4. Comparison of August 14 Frequency Deviation with Other Days in August

Figure 4.1 compares the August 14 frequency deviation with the corresponding frequency deviations from: 1) the weekdays from August 4–August 12; and 2) August 13. For the three scenarios, frequency runs high in the early part of the day because extra generating capacity is committed and waiting to be dispatched for the daily peak. The average frequency deviation for the August weekdays prior to August 14 remains in the high side for all hour periods, but the frequency runs low for August 13 and 14 during the 1000 to 1400 EDT periods, with more than 300 percent lower on August 14 than on August 13 for the 1000 to 1200 EDT period.

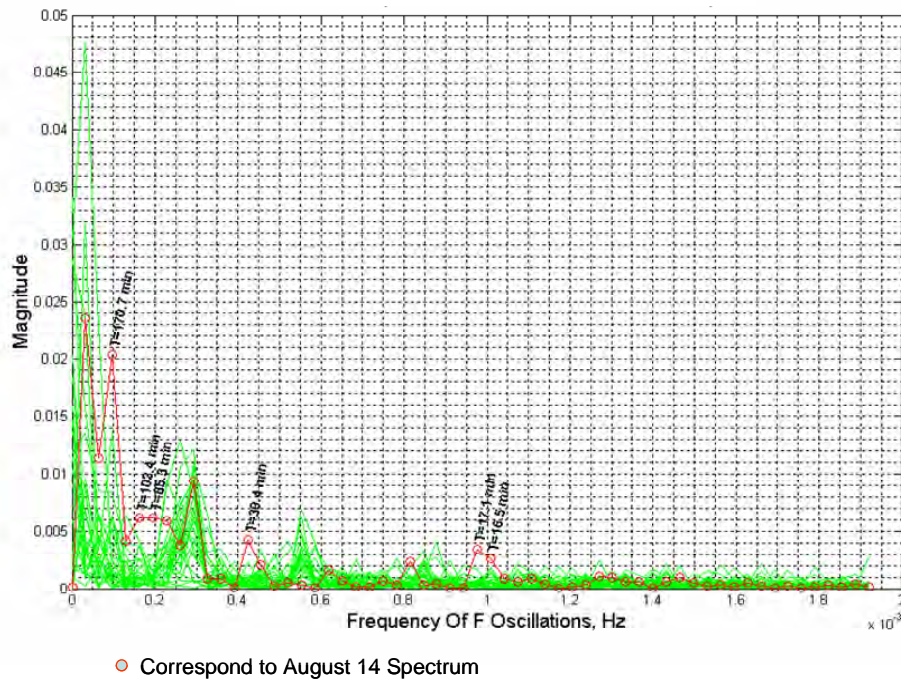
Figure 4.1 — August 14 Hourly Frequency Error Comparison with other August Days



Using the frequency spectrums (obtained by the FFT)⁶ for all days of August 2003, the graph from Figure 4.2 shows that there are no dramatic power magnitude⁷ excursions observed before the blackout on August 14 compared to the other days of August. At the same time, for several modes, there are some power magnitude spikes. It should be noted that most of these spikes correspond to the same periods indicated in the OSISOFT’s report.

In Figure 4.2, the Y axis shows the power magnitude of the phasors that constitute the interconnection frequency error (see footnotes 5 and 6). It should be noted that there is not any pre-established threshold separating the “large” power magnitude from the “small” magnitudes. In this study, FAIT selected a number of phasors with relatively larger magnitudes compared to the rest of the spectrum.

Figure 4.2 — Eastern Interconnection Frequency Deviation Spectrum on August 14 and Other Days of August



⁶ The discrete Fast Fourier Transform (FFT) allows representing a time domain process - in our case, the Interconnection frequency error (= frequency deviation from its scheduled error) changing in time — as a sum of sinusoidal signals (phasors) of different magnitudes, frequency and phases. The maximum magnitudes correspond to the dominant oscillation modes that might be present in the analyzed process. Zero magnitude phasors mean that the corresponding oscillation frequencies are not present in the analyzed signal. The zero frequency phasor corresponds to the constant component for the analyzed signal. The results of the FFT analysis are often represented in the form of the power and phase spectrums where the power magnitudes of oscillations and their phases are plotted against the phasors’ frequency.

⁷ The power magnitude for all phasors except the one with zero frequency is determined as twice the second power of their complex magnitudes, Hz^2 . Here FAIT wants to stress that for the studies, the relative values of power magnitudes are important. This approach allowed FAIT to analyze and compare the power spectrum components without getting into a detailed explanation of their actual mathematical meaning of their physical nature.

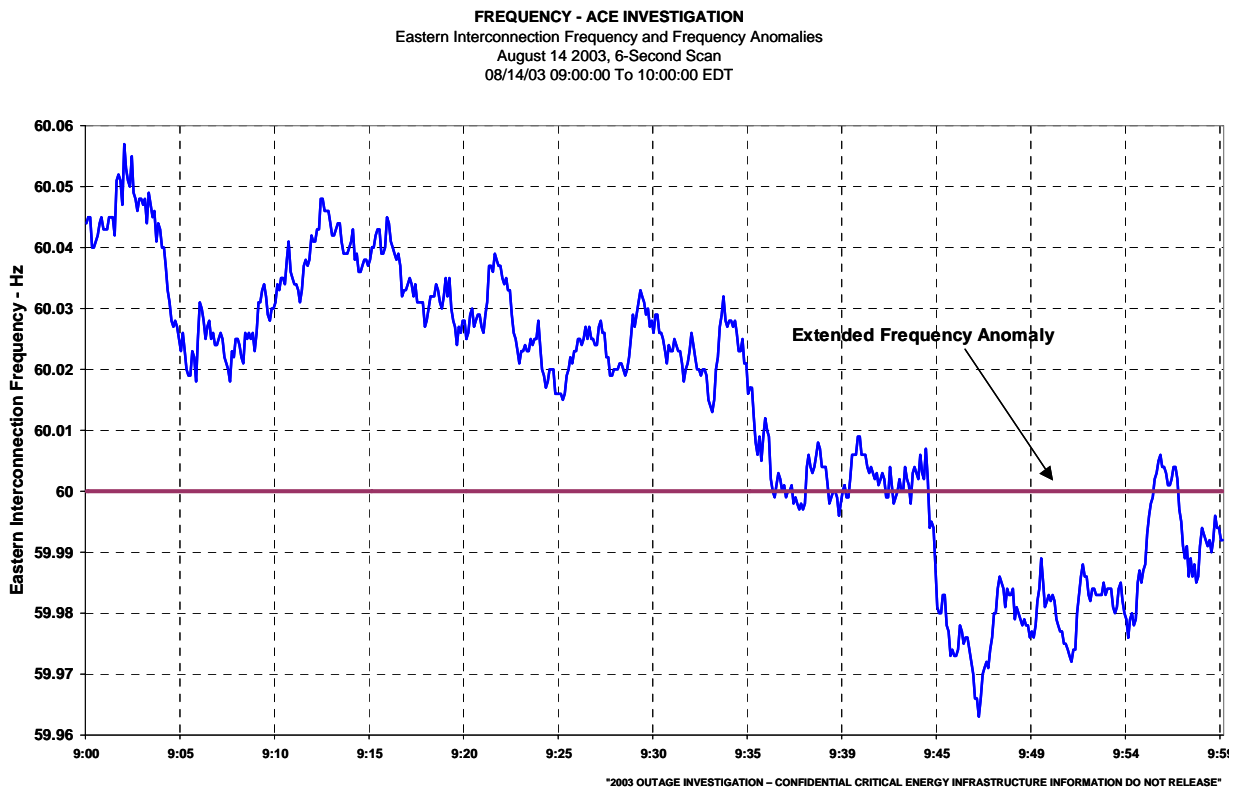
5. Eastern Interconnection Frequency Abnormalities Identified and Analyzed by FAIT

5.1 August 14, 0900–1000 EDT Extended Frequency Anomaly Analysis and Recommendations

The FAIT observations, results, and recommendations for the frequency anomaly of August 14, from 0900–1000 EDT are as follows:

Figure 5.1 reflects the correlation between net ACE and Eastern Interconnection frequency during the frequency anomaly, using the ACE-Frequency one-minute data collected and validated by FAIT. Figure 5.1 also shows an extended frequency anomaly of about 22 minutes during which frequency stayed negative and did not cross zero.

Figure 5.1 — Frequency and Frequency Anomalies



From 0900–0935 EDT and from 0940–0945 EDT, there was a good frequency-to-net ACE correlation. From 0935–0940 EDT, the graphs show a positive net ACE ranging from 2,000 MW to 1,000 MW, with a frequency deviation from 0.025 Hz to 0.0 Hz. From 0945–0955 EDT the net ACE was about -1,100 MW, with the frequency deviation between -0.035 to -0.020. Assuming the sum of the AGC frequency biases for the Eastern Interconnection is 6,250 MW/0.1 Hz for extended frequency, the 0935–0940 EDT and the 0945–0955 EDT periods were abnormal extended frequency periods.

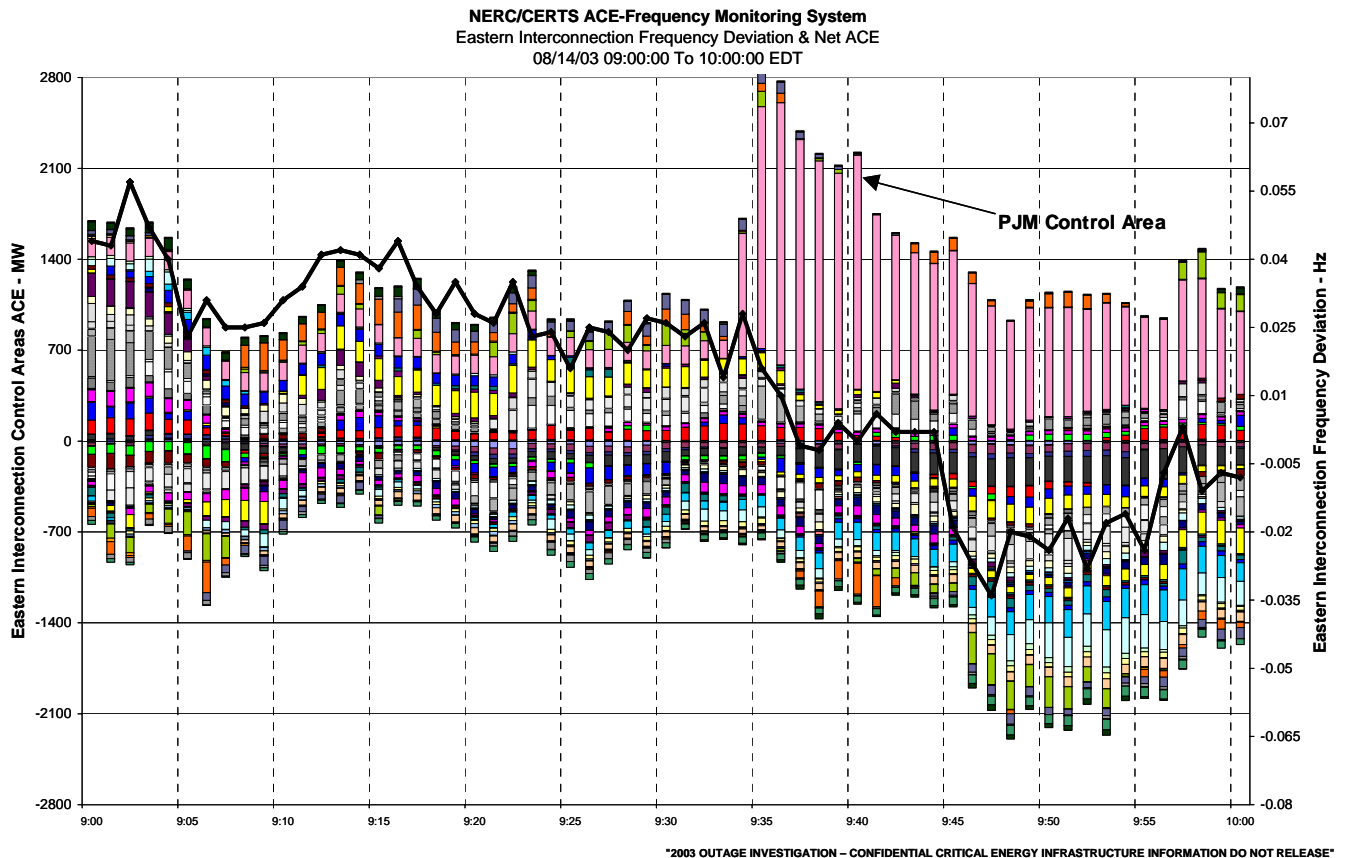
Abnormal for purposes of this report can be defined as significantly different from average or expected behavior of the frequency error. Given that system frequency, on average, is running roughly 10 MilliHertz high, it was considered unusual for the frequency error to go negative and stay there for an extended length of time.

5.1.1 Identify Control Areas Most Impacting the Eastern Interconnection Net ACE and Frequency Deviation.

Figure 5.2 shows the positive and negative net ACE of Eastern Interconnection control areas, above and below the zero-reference, for the 0900–1000 EDT period. For the extended anomaly, Figure 5.2 also shows the PJM control area abnormal ACE behavior.

FAIT observed that the PJM control area operated with the most positive ACE ranging from 2,000 to 1,000 MW from 0925–1000 EDT, the period during which the two frequency abnormalities occurred.

Figure 5.2 — Eastern Interconnection NET ACE and Frequency Deviation



5.1.2 Identify Possible Root Causes for Abnormal Frequency Responses

The NERC Sequence of Events database does not contain data for the 0900–1000 EDT period on August 14. Two PJM documents released to the U.S.-Canada Power System Outage Task Force identified abnormal events during the time of abnormal frequency responses. The first PJM document has a note “PJM EMS communications disruption, on Analog Backup”. The second PJM document states that “PJM experienced a loss of data communication links with member companies control centers on August 14 at 0850 until 0930 EDT. Functions available during that period were: State estimator using last good data, AGC not available, generation control in analog back-up system, not loss of control, and TOs providing back-up monitoring.”

The periods of abnormal frequency responses do not match the documented time period when PJM AGC was not available. FAIT raised several concerns because of this time mismatch. First, why is there a difference of about 30 minutes between PJM generation control using the analog backup system and the period during which they have abnormal ACE? Second, why did the PJM generation control backup system originate a PJM positive ACE ranging from 2,000 to 1,000 MW from 0925–1000 EDT? Third, what are the requirements for a generation-monitoring backup control system, and what is the basic functionality required to control generation in a market environment?

Figure 5.2 shows that the PJM control area was reporting the highest ACE in the range from 1,000 to 2,000 MW during the abnormal periods. The reasons for this are analyzed in Sections 5.1 and 5.1.1 above. No other control areas reported any comparable ACE during the period analyzed.

5.1.3 Data Request and Further Analysis

NERC should request data from PJM that would help clarify the time discrepancies and the possible correlation between their abnormal ACE and abnormal frequency during the time period in which AGC was not available. After PJM responds to the data request, an analysis of the impact of the abnormal frequency should be performed and recommendations proposed.

Question 1: What is your accurate ACE for the time period from 0900–1000 EDT? The question should be posed to PJM accompanied by the data in the Consortium for Electric Reliability Technology (CERTS) bar graph. After 0935 EDT, the PJM ACE jumped up — what caused this trend to happen?

Question 2: What data communications were lost and what data was substituted in place of the normal data? What is the PJM procedure when loss of communications occurs?

5.2 August 14, 0900–1000 EDT Frequency Anomaly Conclusions and Recommendations

Recommendation 1: The RS should follow up on the reasons for PJM’s abnormal ACE from 0900–1000 EDT. The RS should also address other control areas that had negative ACE from 0943–1006 EDT: Southern Company (SOCO), New York ISO (NYISO), Northern States Power (NSP), AMEREN, FRCC, and Central Louisiana Electric Company (CLECO).

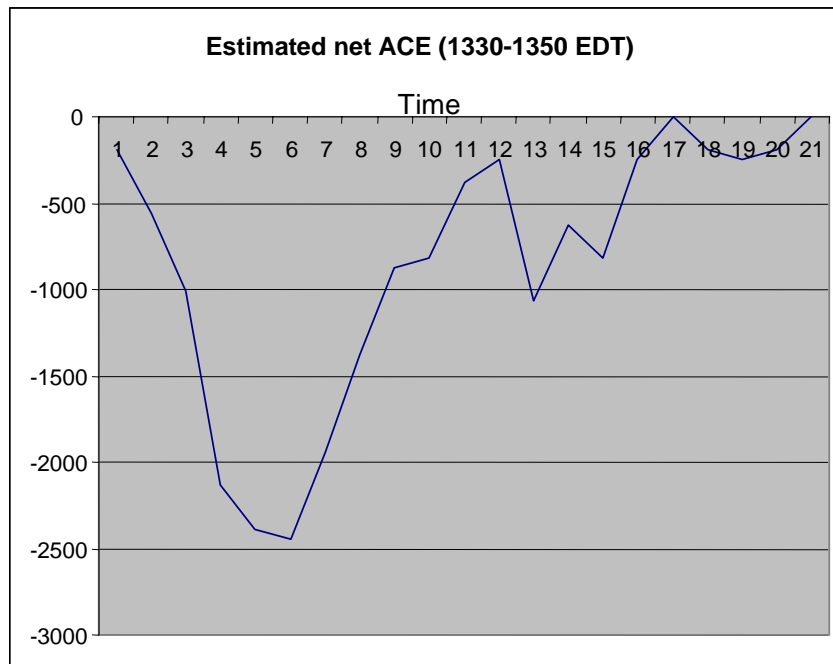
Recommendation 2: Review and update procedures to be followed by reliability coordinators and operating authorities when vital internal or external data communication and/or control processes are lost.

5.3 August 14, 1331:59, 1332:06, 1330–1340 EDT Frequency Response Analysis and Recommendations

is a plot of estimated Eastern Interconnection net ACE for the window of time coincident with the loss of Eastlake 5. The frequency deviation is roughly double the amount that should have been caused by the loss of Eastlake 5.

If the unknown resource shortfall(s) were in the Ohio area or “downstream” of prevailing flows through FirstEnergy, this circumstance would be of particular significance to the investigation.

Figure 5.3 — Estimated Net ACE (1330–1350 EDT)



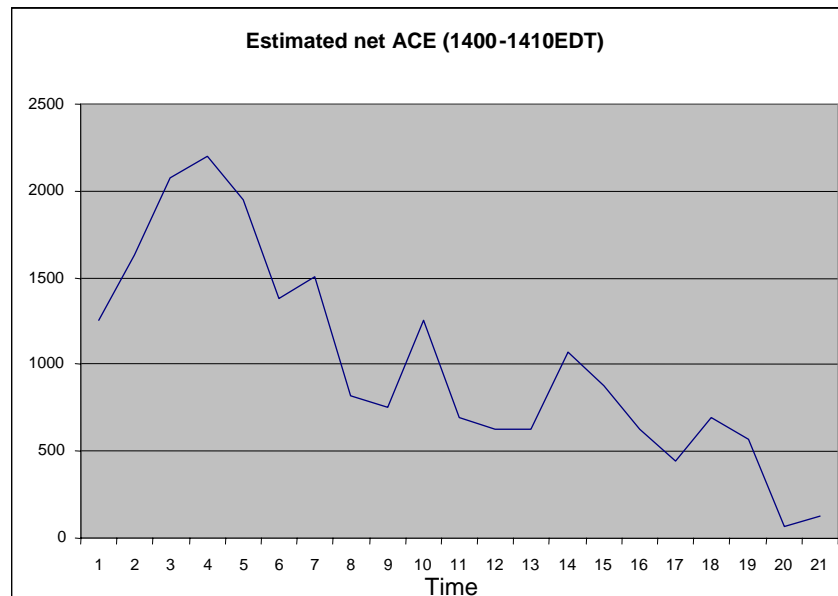
The lack of visibility of the resource shortfall is of concern. Control areas with an AIE of a magnitude that could explain the resource loss include the following.

South Western Power Administration	-200 MW
New York ISO	-132 MW
Southern Company	-107 MW
Cinergy	- 97 MW
Commonwealth Edison	-93 MW
City of Independence Missouri	-91 MW

It is possible that the control areas that were deficient this hour may have purchased energy “on the half hour” or dynamically scheduled the problem to others.

Figure 5.4 is a plot of estimated Eastern Interconnection ACE for the hour beginning immediately after the loss of Eastlake 5 and the other unknown resource(s) shortfall. The “overshoot” was probably caused by overreaction to the previous hour’s shortfall. In other words, the control areas that lost resources are probably the same ones that overscheduled at the top of the following hour. An attempt should be made to identify the resource(s) lost during the hour ending 1400 EDT.

Figure 5.4 — Estimated Net ACE (1400–1410 EDT)



5.4 August 14, 1350–1410 EDT Extended Frequency Anomaly Analysis and Recommendations

Summary

The extended frequency anomaly observed in the Eastern Interconnection from 1350–1410 EDT on August 14, 2003 has the characteristics outlined in Table 1. This specific anomaly has been detected using criteria proposed in Section 2 of this report.

Table 5.1 — Extended Frequency Anomaly Characteristics from 1350–1410 EDT

Duration of extended anomaly period	25 minutes
Max. frequency (1 minute average)	+0.0380 Hz
Average frequency over the anomaly period	+0.0139 Hz

This anomaly was caused by simultaneous positive excursions of the area control errors in Cinergy (CIN), the Tennessee Valley Authority (TVA), NYISO, and SOCO. Based on CERTS one-minute ACE data, these excursions also caused the CPS2 violations listed in Table 5.2.

Figure 5.5 — 1350–1410 EDT Extended Frequency Anomaly

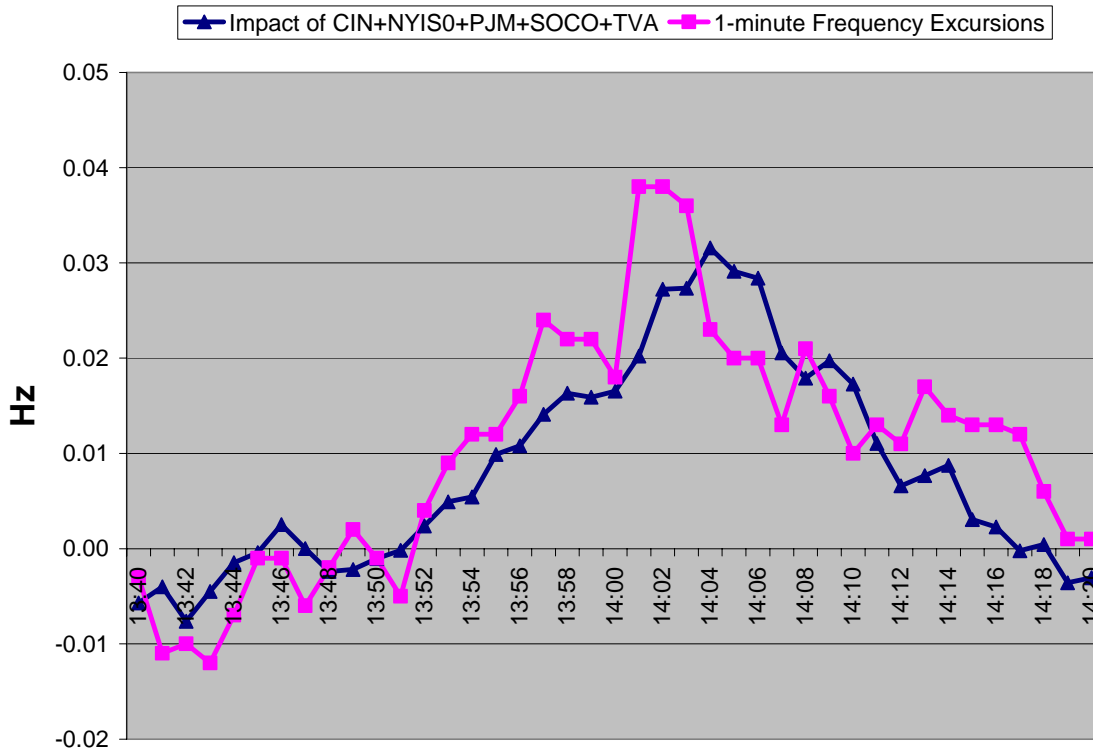


Table 5.2 — (Violations are marked as X)

Control Area	L10 ⁸	Max Ten-minute average of ACE*	Ten-minute interval ending by		
			1400	1410	1420
CIN	83.46 MW	+258.2 MW		X	X
NYISO	132.49 MW	+145.4 MW		X	
TVA	128.43 MW	+279.2 MW	X	X	
SOCO	152.44 MW	+171.3 MW	X		

* Determined at the end of ten-minute intervals

⁸ L10 is the MW limit utilized in the CPS2 portion of the Control Performance Standard. It is the MW limit (plus or minus) within which the average ACE for the clock ten-minute periods (six non-overlapping periods per hour) during a calendar month must be within 90% of the time in order to comply with the CPS1 criteria. If a control area's ACE is less than plus or minus L10, then the control area is assumed (statistically) to not be adversely impacting the reliability of the interconnection. L10 is calculated as the square root of the ratio of the control area's frequency bias to the sum of the frequency biases for all control areas in the Eastern Interconnection multiplied by a constant. See NERC *Operating Manual, Performance Standard Reference Document*.

One-minute CPS1 compliance scores for those control areas remained well above 100 percent and apparently did not help to identify the analyzed Eastern Interconnection frequency problem.

Figure 5.5 shows how the total ACE in these four control areas contributed to the frequency error (the total ACE was expressed as the frequency error by dividing ACE by 3,200 MW/0.1 Hz).

5.4.1 Conclusions and Action Items

1. Although FAIT found no potential links between the analyzed extended frequency excursion and the August 14 blackout, it is recommended that the reasons for the CPS2 violations in CIN and TVA be identified and verified.
2. Data quality needs to be improved including the AIE surveys. Some observed problems are listed below.

5.4.2 Data Problems

1. The Dominion Virginia Power (VAP) control error has apparently a good correlation with the Eastern Interconnection frequency error. At the same time, the corresponding data in the CERTS file seems to be corrupted (it does not match the ten-minute ACE data provided in the NERC AIE database).
2. The data for SOCO and CIN is apparently shifted by minus one hour in the AIE database.
3. The AIE data for NYISO and SOCO does not match the ACE data. At the same time, the ten-minute ACE data reported in the ACE database matches the AIE data provided by CERTS.

5.5 August 14, 1330–1340 EDT Frequency Anomaly Conclusions and Recommendations

Recommendation: Numerous quality issues have arisen during the FAIT analysis. In addition to time stamping, data synchronization, and definition of sign configuration for meter reading, good practices should be established for recording hourly data vs. one-minute data. Whichever is controlled should be monitored, recorded, and used as the measurable standard.

FAIT suspects that the data quality issue may have negative reliability implications. There are no specific problems in any local areas that FAIT identified as a violation of policy. As previously shown, four control areas had normal ACE swings, which collectively caused an 864.1 MW swing that FAIT considers to be significant.

Recommendation: Develop real-time or near real-time monitoring requirements that can be used to identify problems immediately. Obtain a tool that compares the net ACE to the frequency deviation in order to give an indication of bad data to the operators immediately.

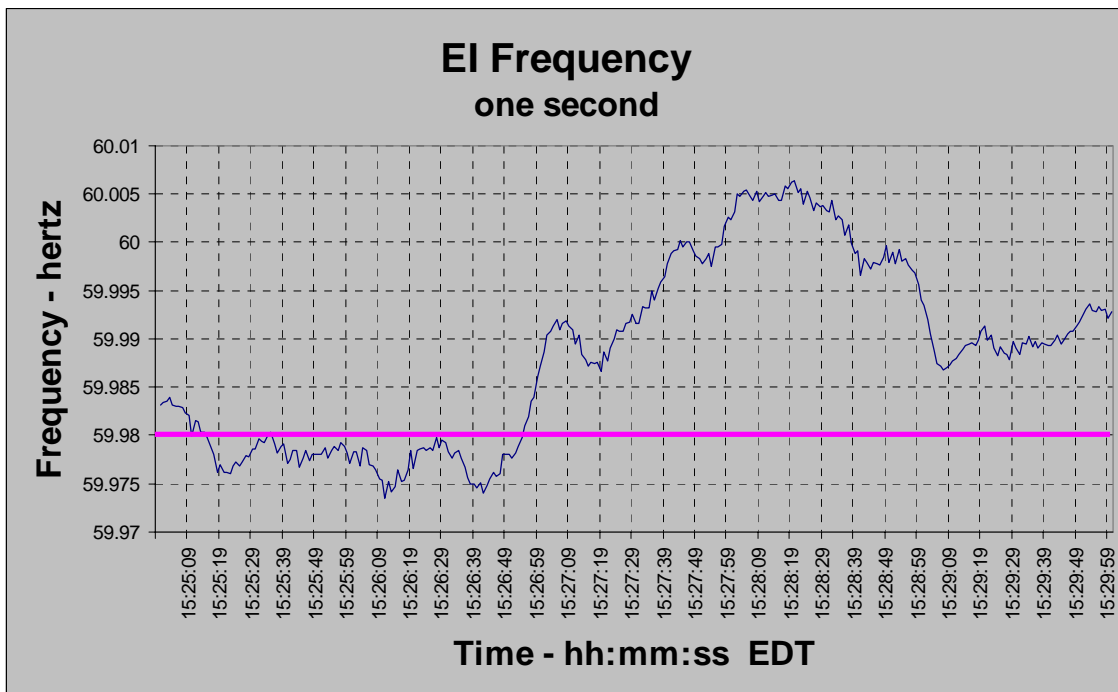
5.6 August 14, 1520–1600 EDT Frequency Anomaly Analysis and Recommendation and Impact of Reserves

15:27:12 — Significant frequency rise of 0.033 Hz equivalent to about 1,500 MW

FAIT did not identify an item that reflects the load loss within the sequence of events listed for this time frame. Turning to individual control area ACE, the following control areas exhibited four or more minutes of sustained positive ACE. Members of FAIT with Eastern Interconnection experience indicated that most of these individual ACE averages were within normally expected variation for their relative size.

Control areas with four or more minutes of sustained positive ACE: CPLE, CIN, DUK, IMO, ISNE, MECS, MHEG, MPS, NIPS, NPPD, SIGE, SOCO, TVA, and VAP.

Figure 5.6 — Eastern Interconnection Frequency at 15:27:12 EDT



Frequency declined during this time frame. If load loss occurred, it cannot be confirmed from the frequency data.

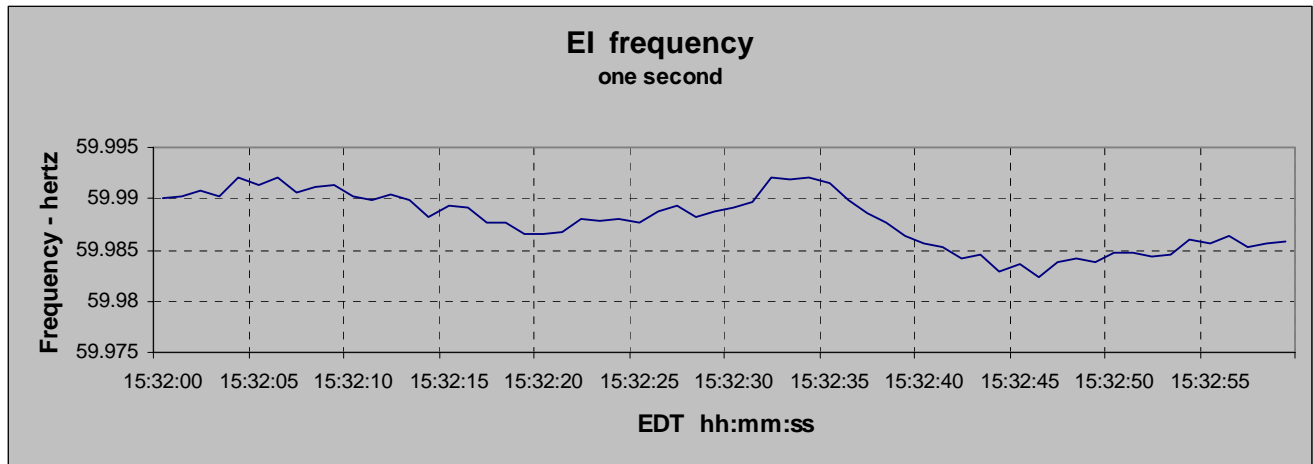
Table 5.3 — Sequence of Events at This Disturbance

Time	Generator	Line
08/14/03 15:32:00		15:32:03 Hanna-Juniper 345 kV
08/14/03 15:36:00	15:36:11 Springdale #2 44 MW	
08/14/03 15:39:00		15:39:17 Pleasant Valley-West Akron 138 kV sags into distribution
08/14/03 15:41:00		15:41:35 Star-South Canton 345 kV
08/14/03 15:43:00		15:43:00 Gloverdale-Torrey 138 kV
08/14/03 15:44:00		15:44:12 East Lima-New Liberty 138 kV sags into distribution 15:44:40 Pleasant Valley-West Akron 138 kV sags into distribution
08/14/03 15:45:00		15:45:41 Canton Central-Tidd 345 kV
08/14/03 15:52:00		15:52:00 E Lima-N Findlay 138 kV
8/14/03 15:59:00		15:59:00 West Akron Bus trips

15:32:35 — Hanna-Juniper 345 kV and Harding-Juniper 345 kV trip in this time frame

During the eleven seconds of frequency decline, an apparent 294 MW of load increase occurred, possibly accompanied by increased line losses. It appears that the 294 MW of load increase was the reason for the frequency decline.

Figure 5.7 — Eastern Interconnection Frequency at 15:32:35 EDT



Associated Events from One Second Frequency Data :

$\beta_{EI} \cong 32,000 \text{ MW/Hz.}$

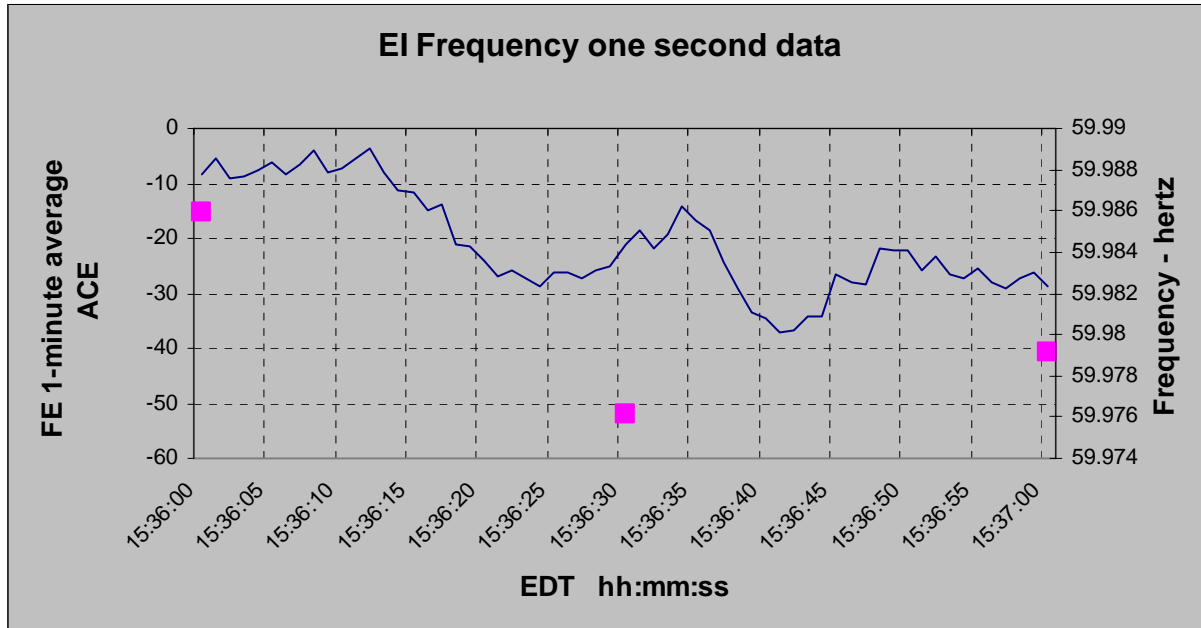
Point	Time	Delta Time	Frequency	Delta Frequency	Estimated Delta MW	Comments
P ₀	15:32:35		59.9915			
P ₁	15:32:46		59.9823	-0.009	-294	possible line losses increase?

FE ACE -25 MW and then recovered

15:36:11 — FE Springdale #2 unit trip — 44 MW

Considering the load-frequency correlation, the change in frequency suggests that 198 MW was lost. (See table below.) The chart includes an overlay of the FE one-minute ACE. It decreases by an amount equivalent to the generation lost. Over the next ten-minutes, the ACE does not recover to pre-event level.

Figure 5.8 — Eastern Interconnection Frequency at 15:36:11



Associated Events from One Second Frequency Data:

$\beta_{EI} \cong 32,000 \text{ MW/Hz.}$

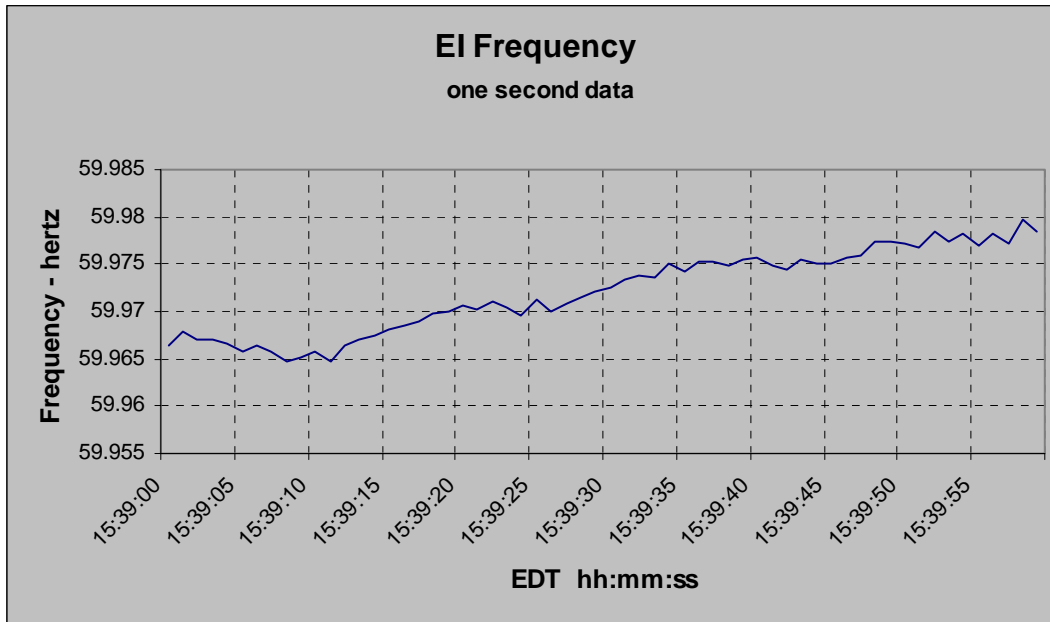
Point	Time	Delta Time	Frequency	Delta Frequency	Estimated Delta MW	Comments
P ₀	15:36:11		59.9885			
P ₁	15:36:24	0:00:13	59.9823	-0.006	-198	Springdale #2 trips 44 MW

FE ACE: changes from -15 MW to -50 MW. Does not recover in ten minutes.

15:39:17 — Pleasant Valley-West Akron 138 kV sags into distribution circuits

The frequency does increase, indicating possible load loss of 349 MW. However, the FE ACE does not change. Since the frequency increases over 41 seconds, it is concluded that the load loss cannot be confirmed.

Figure 5.9 — Eastern Interconnection Frequency at 15:39:17 EDT



Associated Events from One Second Frequency Data:

$\beta_{EI} \cong 32,000$ MW/Hz.

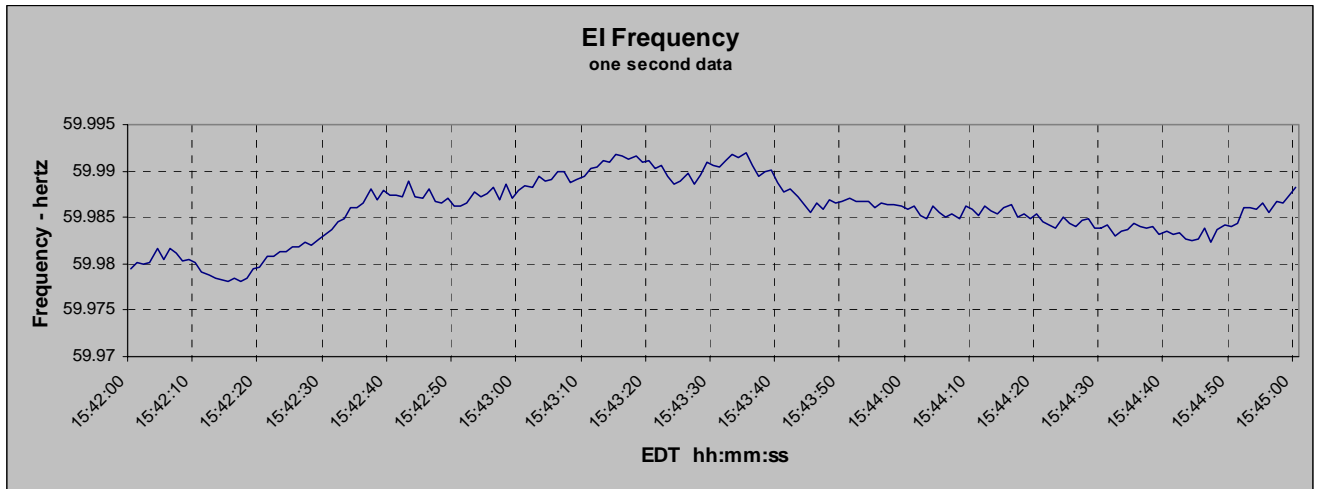
Point	Time	Delta Time	Frequency	Delta Frequency	Estimated Delta MW	Comments
P ₀	15:39:17		59.9689			
P ₁	15:39:58	0:00:41	59.9798	0.011	349	Pleasant Valley West Akron 138 kv sags into distribution

FE ACE: no apparent change

- 15:42:05 — Pleasant Valley-West Akron 138 kV sags into distribution
- 15:44:12 — East Lima-New Liberty 138 kV sags into distribution
- 15:44:40 — Pleasant Valley-West Akron 138 kV sags into distribution

Frequency increases somewhat during this time frame, but none of it suddenly. Frequency change indicates potential 179 MW load loss. FE ACE remains constant at -85 MW. FAIT suspects that FE ACE is not a reliable indicator; it is concluded that the load loss cannot be confirmed.

Figure 5.10 — Eastern Interconnection Frequency at 15:42:05–15:44:40 EDT



Associated Events from One Second Frequency Data:

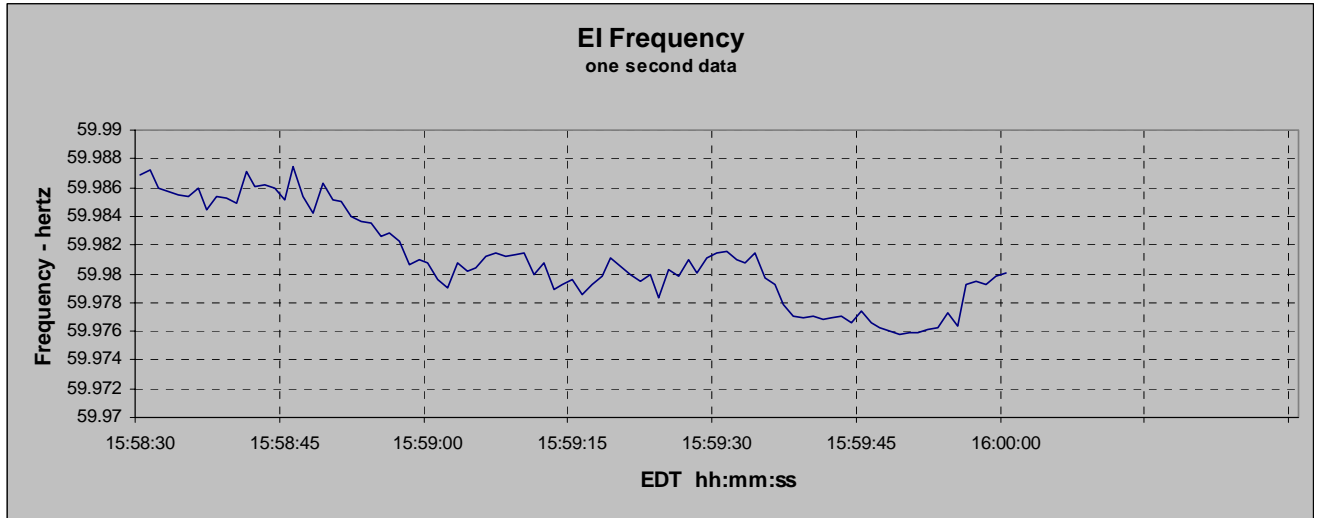
$\beta_{EI} \cong 32,000 \text{ MW/Hz.}$

Point	Time	Delta Time	Delta Frequency	Estimated Delta Megawatts	Comments
P ₀	15:42:05		59.9805		Pleasant Valley-West Akron 138 kV sags into distribution
P ₁	15:42:34	0:00:29	59.9861	0.006	179
P ₂	15:44:12		59.9862		East Lima-New Liberty 138 kV sags into distribution
P ₃					
P ₄	15:44:40		59.9835		Pleasant Valley-West Akron 138 kV sags into distribution

FE one-minute ACE: remains unchanged at -85 MW.

15:59:00 — West Akron 138 kV bus trip

Figure 5.11 — Eastern Interconnection Frequency at 1559 EDT



Associated Events from One Second Frequency Data:

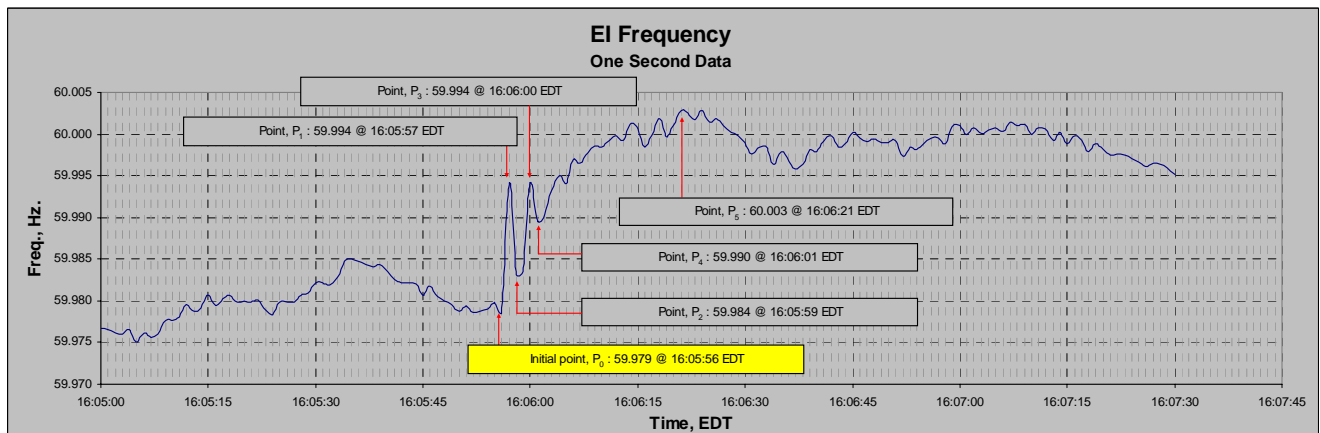
$$\beta_{EI} \cong 32,000 \text{ MW/Hz.}$$

Point	Time	Delta Time	Frequency	Delta Frequency	Estimated Delta MW	Comments
P ₀	15:59:00		59.9808			
P ₁	15:59:10	0:00:10	59.9814	0.001	19	West Akron 138 kV bus trip ???

5.7 August 14, 2003 Frequency Response Analysis and Recommendations

FAIT correlated ACE changes with frequency deviations; it looked at the sequence of events (SOE) and then at the ACE to make a correlation between the data and what happened.

Figure 5.12 — Eastern Interconnection Frequency at 16:06:14 EDT



Associated Events from One-Second Frequency Data

Point	Time	Delta Time	Frequency	Delta Frequency	Estimated Delta MW	Comments
P ₀	16:05:56	0:00:01	59.979			
P ₁	16:05:57	0:00:02	59.994	.0015	480	Sudden loss of Sammis-Star Line, 1,700 MVA
P ₂	16:05:59	0:00:01	59.984	-0.010	-320	Sudden loss of generation – unit trip? None identified Sudden loss of load – transmission breaker operation? None Identified
P ₃	16:06:00	0:00:01	59.994	0.010	320	Sudden loss of generation – unit trip? None identified.
P ₄	16:06:01	0:00:01	59.990	-0.004	-128	Gradual loss of load – voltage collapse? None identified.
P ₅	16:06:02	0:00:20	60.003	0.013	416	

Associated Events from SOE Table

16:05:55	Dale-West Canton 138 kV line trips both ends, recluses West Canton only – 221 MVA
16:05:57	Sammis-Star 345 kV line trips and locks out – 2,850 Amps, roughly 1,700 MVA
16:06:01	Star 138/69 kV transformer #6 low side trips
16:06:01	Star-Dale 79 kV line trips (loading unknown)
16:06:02	Star-Urban 138 kV line (loading unknown)
16:06:09	Richland-Ridgeville-Napoleon Stryker 138 kV line (loading unknown)
16:06:15	Piney Creek Plant (33 MW rating, 31 MW loading)
16:07:00	Handsome Lake #1,2,3,4 (operating as synchronous condenser) 69 Mvar

Conclusion:

No combination of load and/or generation loss explains the frequency oscillations seen during this period.

Speculation:

Combined loss of Dale-West Canton and Sammis-Star (~1,921 MVA) may have caused a temporary power oscillation which lasted roughly 30 seconds then is damped out. As can be seen from the graph below, there are at least eleven cycles ranging from two to four seconds each. Only cycles C₁ and C₂ are significantly large to attract attention, however, the continuation of the cyclic behavior may indicate an oscillatory tendency for that period of time. Note that the frequency shift from the valley of cycle C₁ to the peak at cycle C₉ is 0.024 Hz or the equivalent of about 768 MW loss of load.

Figure 5.13 — Eastern Interconnection Frequency — Oscillation Scenario

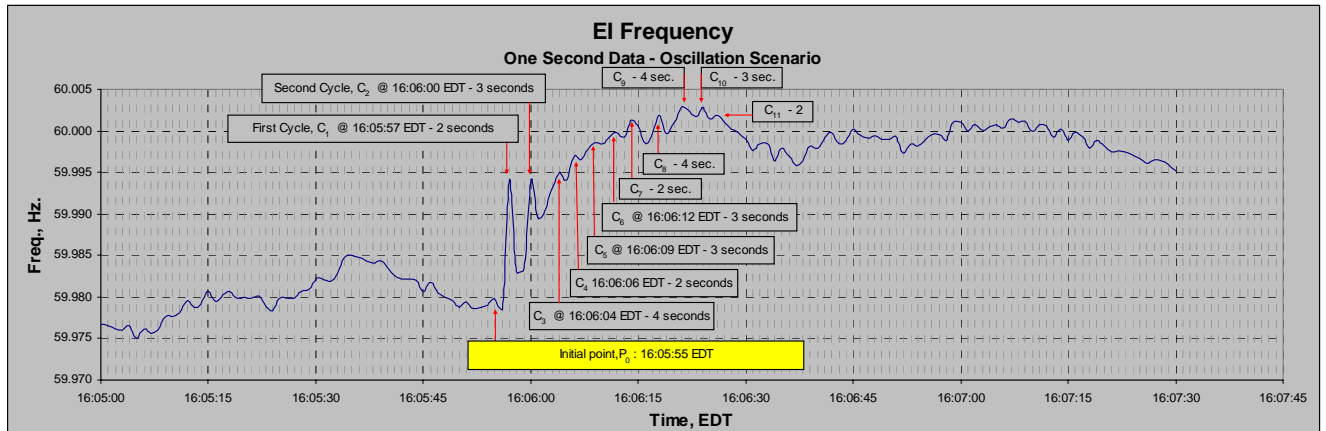
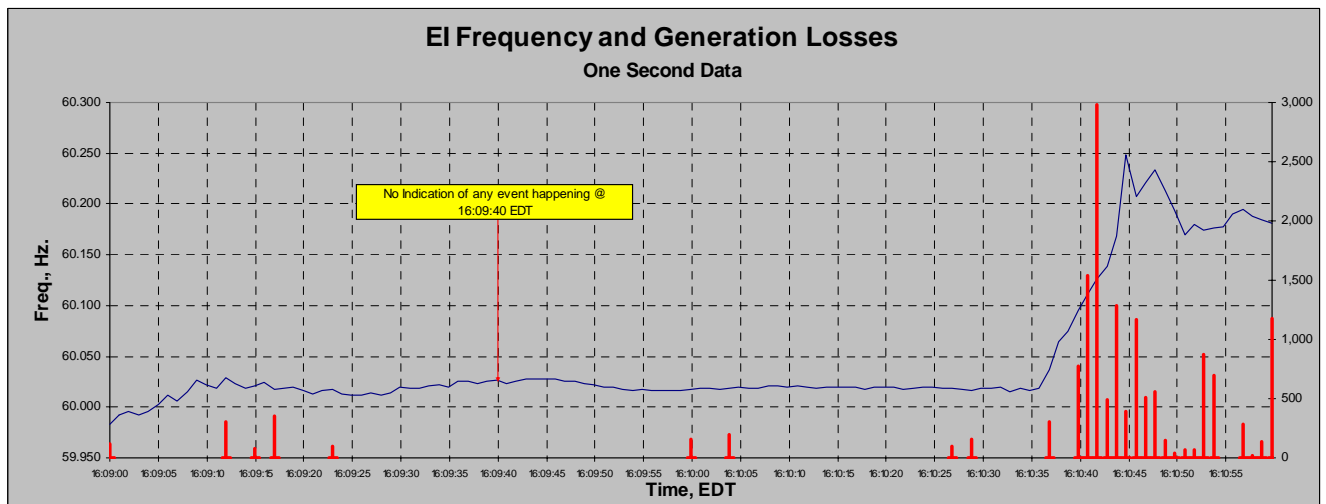


Figure 5.14 — Eastern Interconnection Frequency and Generation Losses at 16:09:40



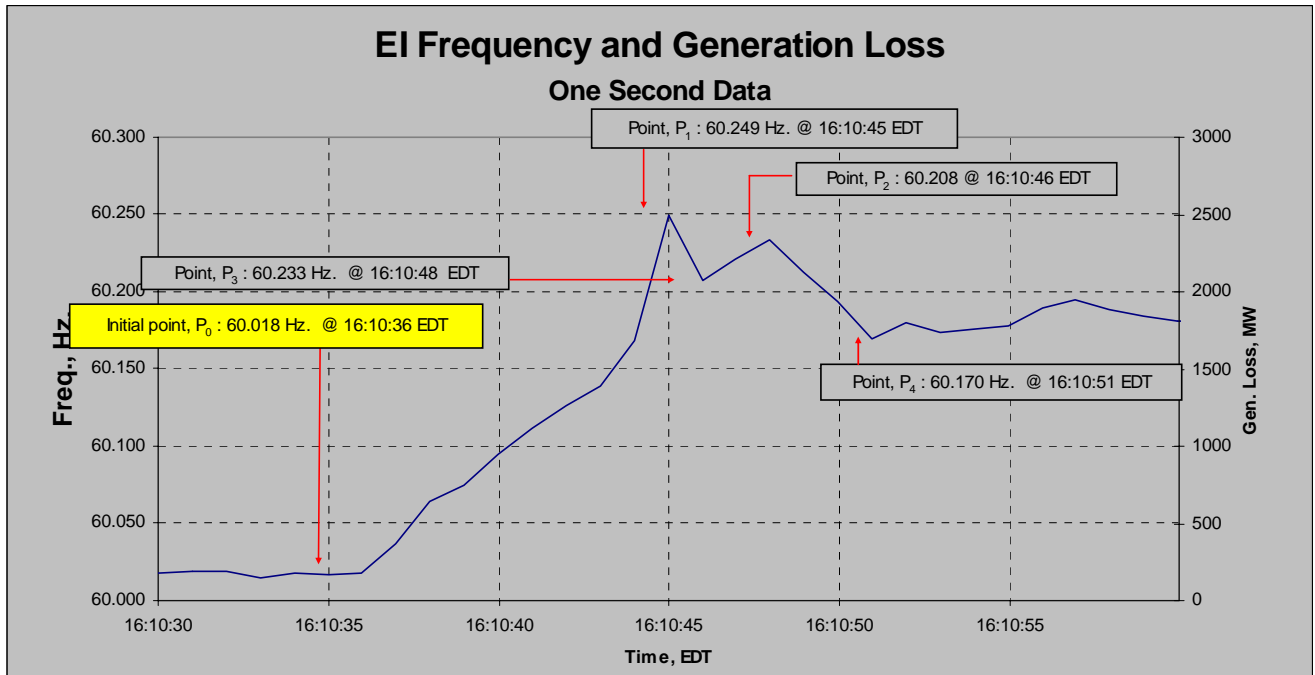
Observation:

Initial FAIT data indicating an event at 16:09:40 EDT appears to be inaccurate
 Actual event apparently referred to in FAIT assignment appears to have started at 16:10:36 EDT
 If there is any correlation between frequency and unit trips from 16:09:00 until 16:11:00, it is not readily apparent.

Conclusion:

No combination of load and/or generation loss explains the frequency oscillations seen prior to initiation of cascading outages.

Figure 5.15 — Eastern Interconnection Frequency and Generation Loss at 16:10:36



Associated Events from One-Second Frequency Data:

$\beta_{EI} \cong 32,000 \text{ MW/Hz}$

Point	Time	Delta Time	Frequency	Delta Frequency	Estimated Delta MW	Comments
P ₀	16:10:36		60.108			
P ₁	16:10:45	0:00:09	60.248	0.231	7,392	Rapid load loss ramp – cascading transmission outages/voltage collapse
Conclusion	16:10:46	0:00:01	60.208	-0.041	-1,312	Sudden loss of generation – unit trips?
P ₃	16:10:48	0:00:02	60.233	0.025	800	Sudden loss of load – transmission breaker operation?
P ₄	16:10:51	0:00:03	60.170	-0.063	-2,016	Rapid loss of generation – multiple unit trip?

Associated Events from SOE Table
See 16:09:40 SOE Timeline

Conclusion

No combination of load and/or generation loss explains the frequency oscillations seen during this period.

16:10:36 — Frequency
16:10:38 — First separation
16:10:39 — Load shedding begins.
16:10:40 — The first islanding started.

Question: At 16:11:00, when did Fitzpatrick trip off line? There appears to be a difference between thermal and energy data. SOE states that at 16:11:39 , 824 MW tripped off line.

5.8 Fast Fourier Transform Analysis of Frequency Excursions Prior to August 14 Blackout

Summary

The discrete Fast Fourier Transform (FFT) allows the representation of a time domain process (in this case, the interconnection frequency error changing in time) as a sum of sinusoidal signals (phasors) of different magnitudes, frequency, and phases. The maximum power phasors correspond to the dominant oscillation modes that might be present in the analyzed process. These dominant modes are often hidden from the naked eye because of their interference with the other modes. The results of the FFT analysis are often represented in the form of the power and phase spectrums where the power magnitudes of oscillations and their phases are plotted against the phasors' frequency. The inverse FFT transform (IFFT) converts the spectrum back to the time domain, so that each oscillation or any selected combination of oscillations can be viewed separately. If all phasors are included in IFFT, the original signal is restored with certain accuracy.

OSIsoft's paper⁹ contains the interesting idea of applying the FFT analysis to determine possible oscillations of the interconnection frequency error prior to the August 14 blackout. However, the analysis conducted by FAIT, although detecting some dominant frequency error oscillations and patterns, did not confirm OSIsoft's concerns regarding their abnormal nature, nor did it find abnormal significant periodic demand-supply power mismatches. Similar dominant modes of a comparable magnitude were observed for the other days of August.

The revelation of some periodic patterns of Eastern Interconnection frequency error by applying the FFT analysis is interesting, and it might be potentially useful for the analyses of the interconnection frequency excursions, ACE signals, interchanges, etc. Although these research opportunities are exciting, they appear to be irrelevant to the analysis of the August 14 blackout.

The FAIT frequency spectrum analysis reached the same main conclusion as the independent study conducted by Gary Bullock. Pre-disturbance frequency was not a direct root cause for the blackout.

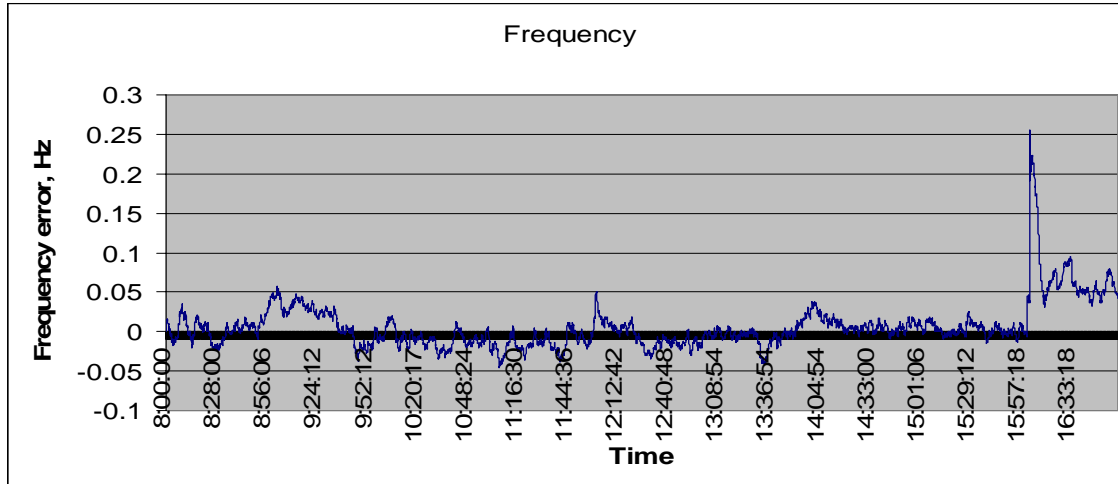
Analysis of Six-Second Frequency Error Samples Before the August 14 Blackout

The six-second frequency error curve observed on the day of the blackout is shown in Figure 5.16. Note that the curve has an abnormal "tail" after 1610 EDT. This part of the curve corresponds to the period where the blackout was already in progress, and frequency

⁹ *Comments on the DOE Blackout Report*, November 28, 2003.

measurements were affected by this process. In the subsequent analysis, we eliminate this tail from consideration by limiting the study period from 0800–1610 EDT for all days.

Figure 5.16 — Frequency Error¹⁰ Curve (August 14, six-second data)



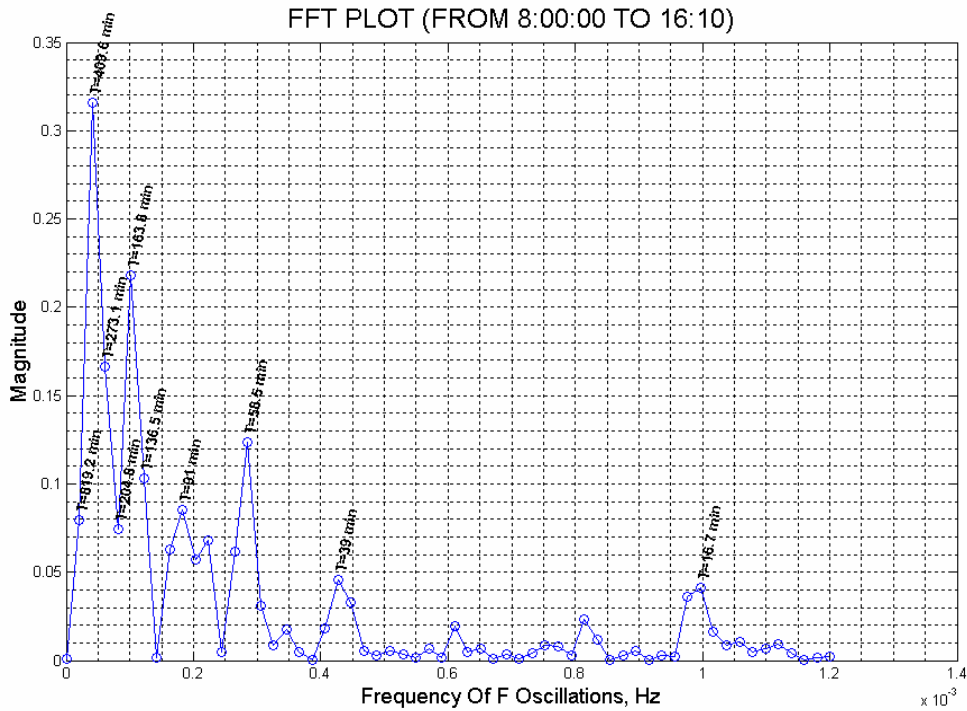
Analysis Without The Abnormal Tail After 1610 EDT

Figure 5.17 represents the FFT plot for the six-second frequency excursions in the period 0800–1610 EDT (without the tail). The Y axis in Figures 5.16 and 5.17 is the power magnitude.¹¹ The dominant modes and their periods in minutes are indicated.

¹⁰ Frequency error is the deviation of the interconnection frequency from its schedule.

¹¹ The power magnitude for all phasors except the one with zero frequency is determined as twice the second power of their complex magnitudes, Hz^2 . Here FAIT wants to stress that for these studies, THE RELATIVE VALUES OF POWER MAGNITUDES ARE IMPORTANT. This approach allowed FAIT to analyze and compare the power spectrum components without a detailed explanation of their actual mathematical meaning of their physical nature.

Figure 5.17 — FFT Plot Without Tail (August 14 six-second data)



Comparison of Six-Second FFT Results With One-Minute FFT Results

Figure 5.18 shows the August 14 FFT plot for the one-minute data resolution. The profile of the power spectrum for one-minute data is rather close to the profile shown in Figure 5.17 for the six-second data. Some differences are observed mainly on the lower frequency side of the spectrum. This fact needs an explanation. FAIT's hypothesis is that the analyzed period (8 hours, 10 minutes) is too short to accurately and uniquely reflect the phasors' periods of the order of four-to-eight hours at a one-minute sampling frequency. A kind of non-uniqueness is caused, so that the lower-frequency processes could be described by different combinations of phasors depending on the number of samples.

To confirm this hypothesis, FAIT applied the inverse FFT transform to the sum of the first five phasors shown in (six-second data) and the sum of the first three phasors shown in Figure 5.18 (one-minute data). Results are presented in Figure 5.19 and Figure 5.20.

Figure 5.19 — August 14 Inverse FFT for Five Lower Frequency Phasors (six-second data)

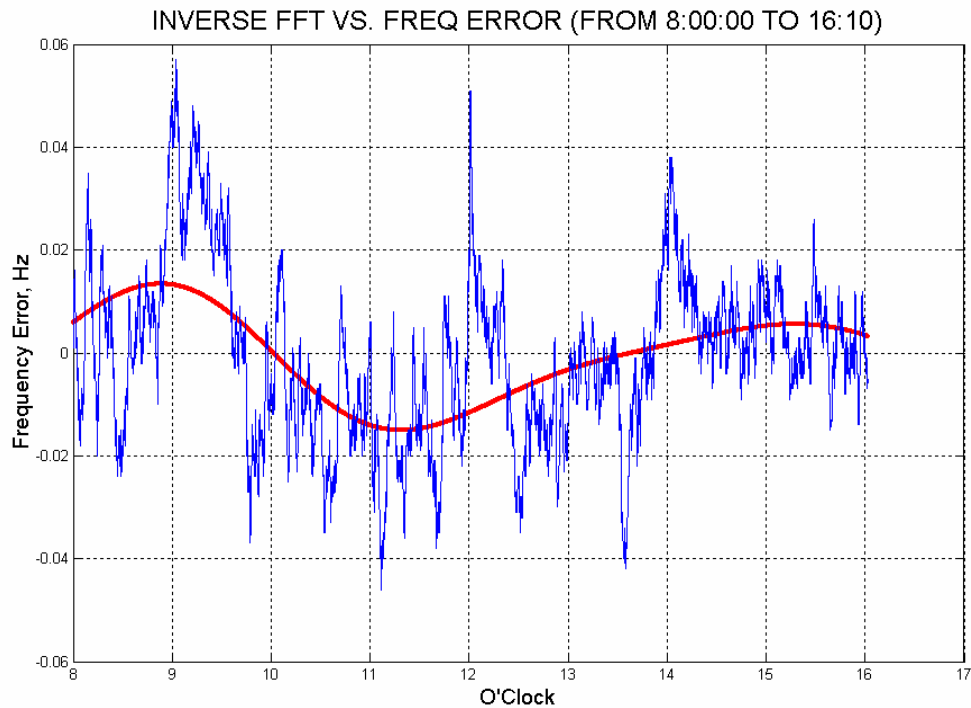
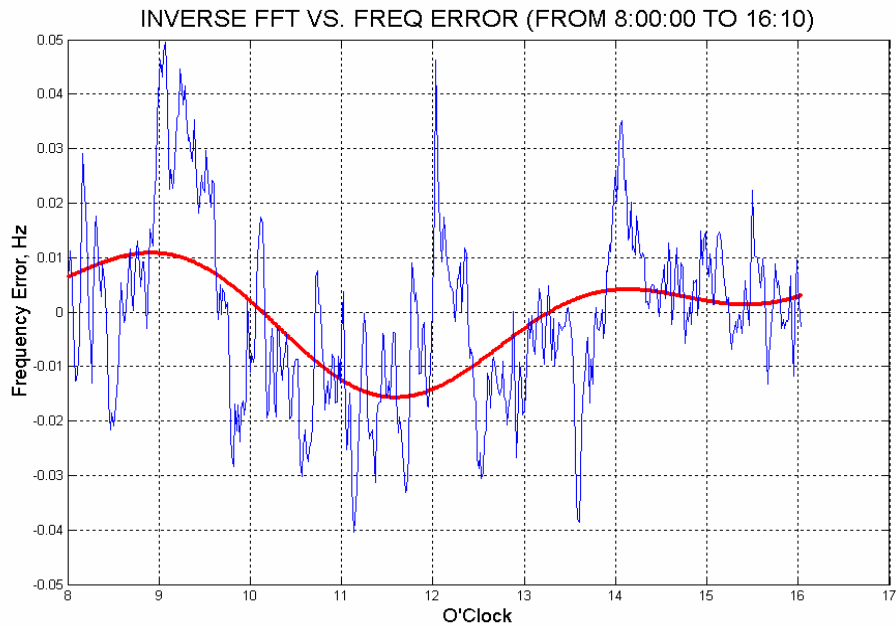


Figure 5.20 — August 14 Inverse FFT for Three Lower Frequency Phasors (one-minute data)



The obtained time-domain curves have very similar shapes and magnitudes. This result confirms that the lower-frequency components are reflecting the same processes for both resolutions. Therefore, we can use the one-minute data for the purposes of this study if we are careful enough not to analyze the lower-frequency modes individually at the one-minute sampling period.

Analysis of Dominant Oscillations on August 14

Figures 5.21–5.24 show four dominant modes observed prior to the August 14 blackout.

Figure 5.21 — 512-minute (~8 hour) Oscillation Prior to August 14 Blackout

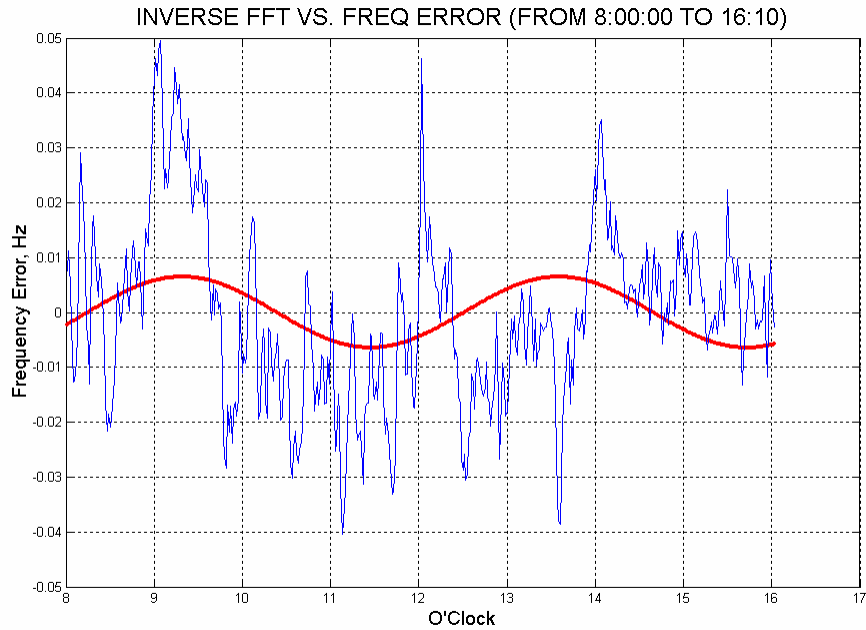


Figure 5.22 — 256-minute (~4 hour) Oscillation Prior to the August 14 Blackout

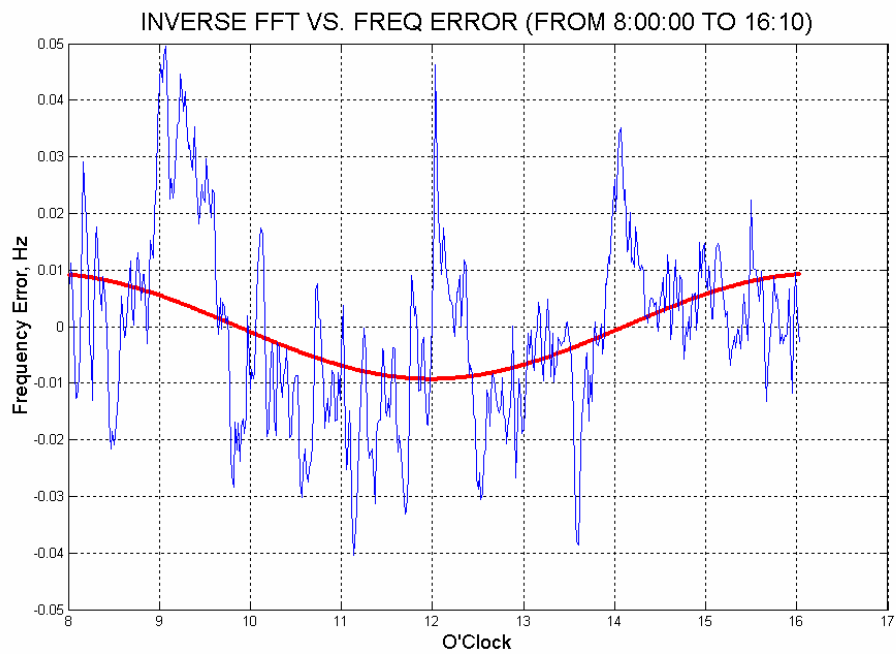


Figure 5.23 — 171-minute (~3 hour) Oscillation Prior to the August 14 Blackout

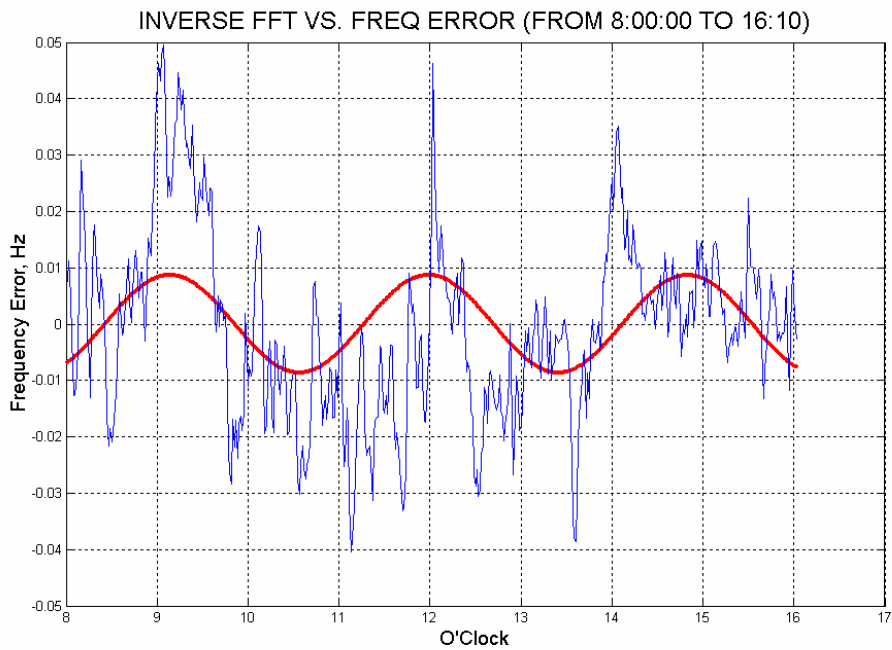
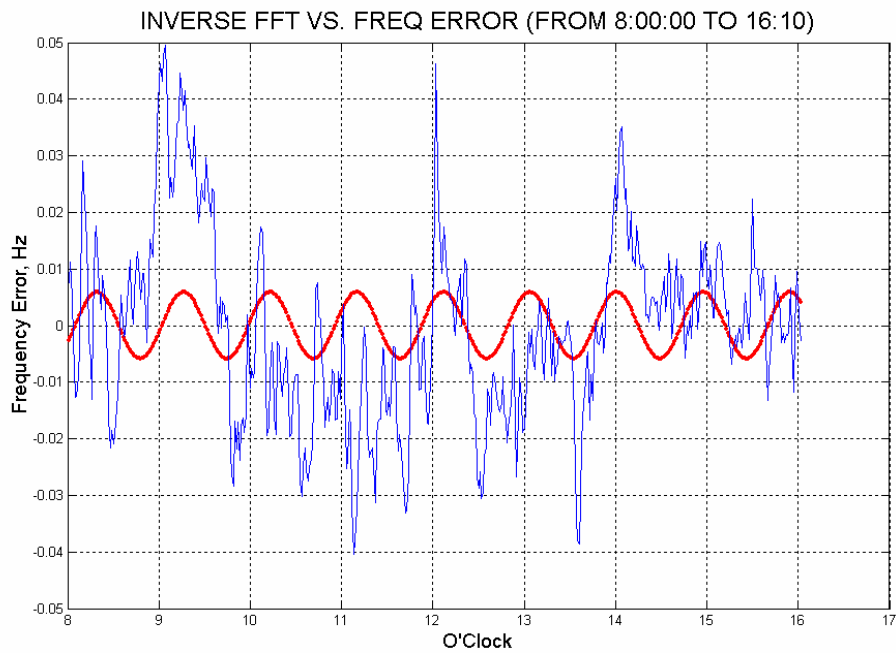


Figure 5.24 — 59-minute (~1 hour) Oscillation Prior to the August 14 Blackout

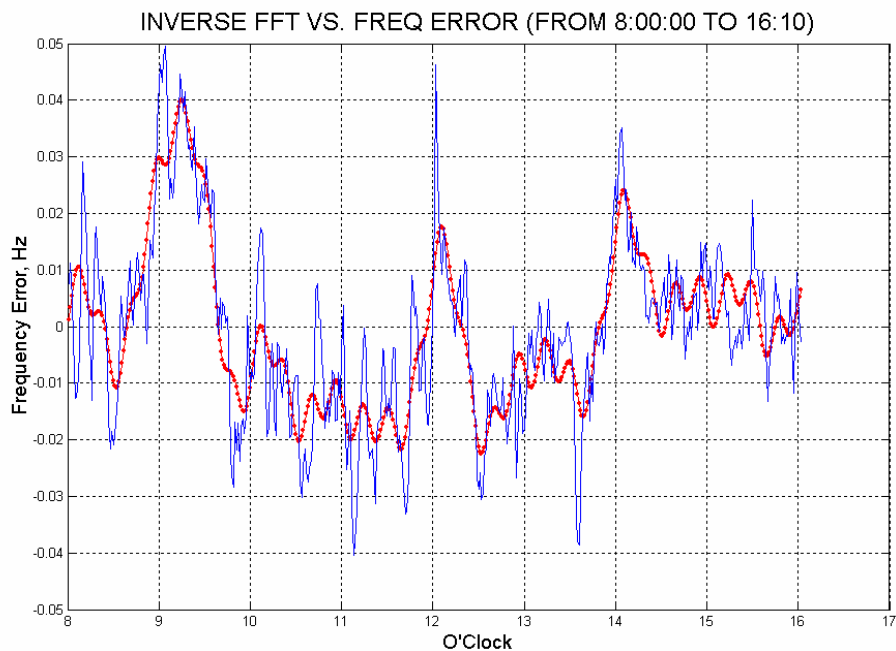


The magnitudes of these oscillations were in the range from 0.006 to 0.01 Hz (which corresponds to the power mismatch swings of approximately 190–320 MW). Again, one should be very careful when analyzing the FFT phasors individually. We have observed already how different phasors could produce similar time-domain processes considered simultaneously (see Figure 5.19 and Figure 5.20). It is not always clear whether each individual phasor reflects a specific physical process, or only their combinations have a meaningful physical sense.

FAIT’s first objective in this study was to analyze whether the dominating modes of the interconnection frequency error were abnormal on the day of the blackout. Plots in Figure 5.25–5.28 demonstrate a variety of shapes of the analyzed signal throughout. It is shown that the SUMMARY SHAPE OF DOMINANT OSCILLATIONS WAS NOT ABNORMAL on August 14.

At first glance, the last three modes shown in Figures 5.22–5.24 have a poor correlation with the shape of the frequency error curve. Let us see how the sum of dominant phasors presented in Figures 5.21–5.24 work to approximate the frequency error curve (see Figure 5.25).

Figure 5.25 — A Combination of Dominant Oscillations Prior to the August 14 Blackout



The resulting curve becomes very complicated, without a clear periodicity or regularity. Again, it is hard to establish whether the detected modes are individual physical processes, or just products of a mathematical transformation which attempts to present a complicated time-domain process as a sum of sinusoidal elementary processes. Further research is needed to make this judgment.

Were the August 14 Oscillations Different from the Other Days of August?

Daily oscillatory behavior of the Eastern Interconnection frequency error was changing for different days of August. For example, Figures 5.26–5.28 represent two days with visibly different patterns. Figure 5.26 illustrates a sinusoidal hourly pattern modulated by low-frequency modes. Figure 5.27 shows a clear hourly non-sinusoidal pattern modulated by a very low frequency. Figure 5.28 contains an example of mostly irregular processes similar to August 14.

Figure 5.26 — August 24 Dominant Oscillations

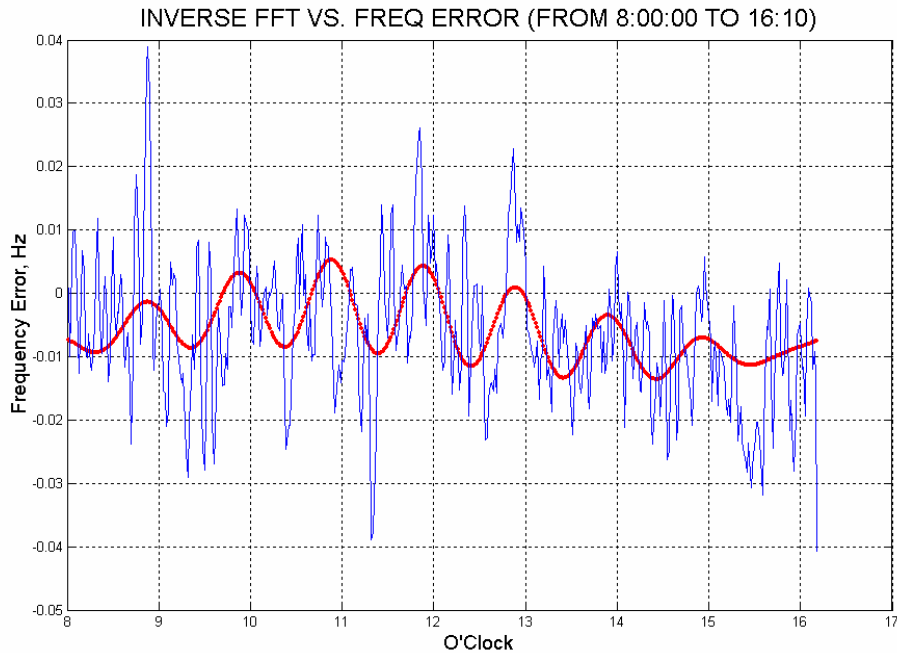


Figure 5.27 — August 26 Dominant Oscillations

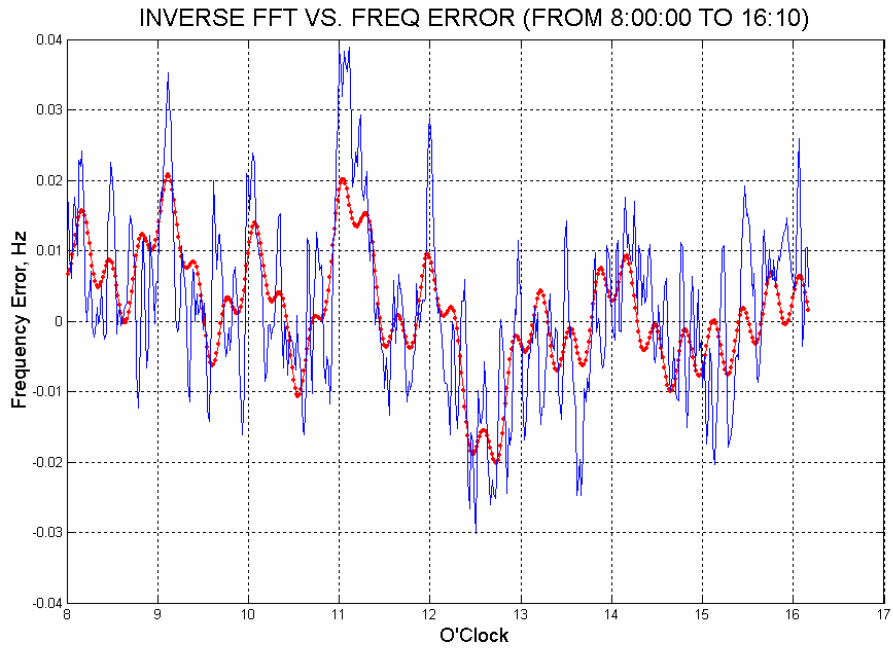
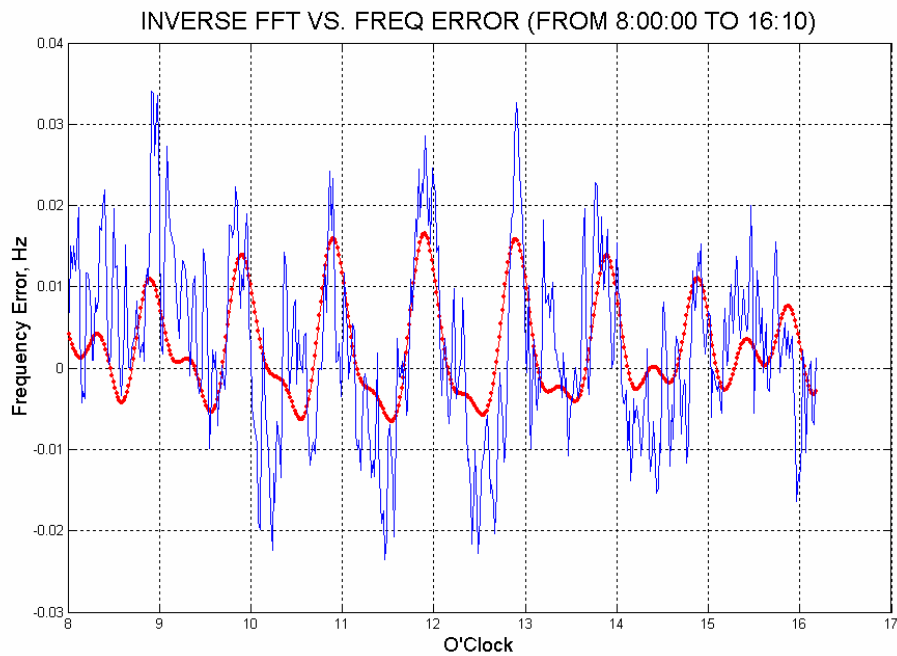
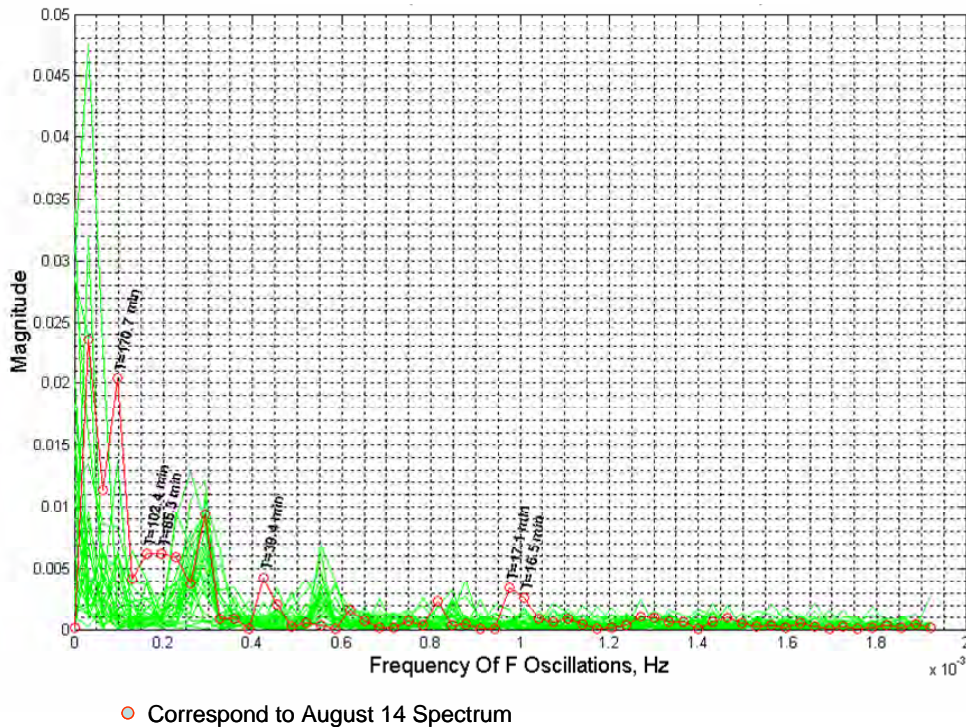


Figure 5.28 — August 4 Dominant Oscillations



Therefore, the resulting shape of dominant oscillations observed on August 14 is not conclusive by itself.

Figure 5.29 — August 14 FFT Spectrum vs. Other Days in August



In order to determine whether the August 14 process was noticeably different compared with the other days of August, we will examine the FFT spectrums and time domain processes. Figure 5.29 displays a combined FFT plot for all 31 days in August. By analyzing Figure 5.29, one can see that there are no dramatic power magnitude excursions observed on August 14 compared to the other days of August. At the same time, for several modes, there are some power magnitude spikes. It should be noted that most of these spikes correspond to the periods indicated in the OSIssoft’s paper. During the other days, these modes were observed as well, although their magnitudes were less than they were on August 14. Therefore, we need to compare the magnitudes of these modes on August 14 against the other days in order to decide whether we have “significant power oscillations” specific to August 14 or not. Table 5.4 summarizes the phasors of interest:

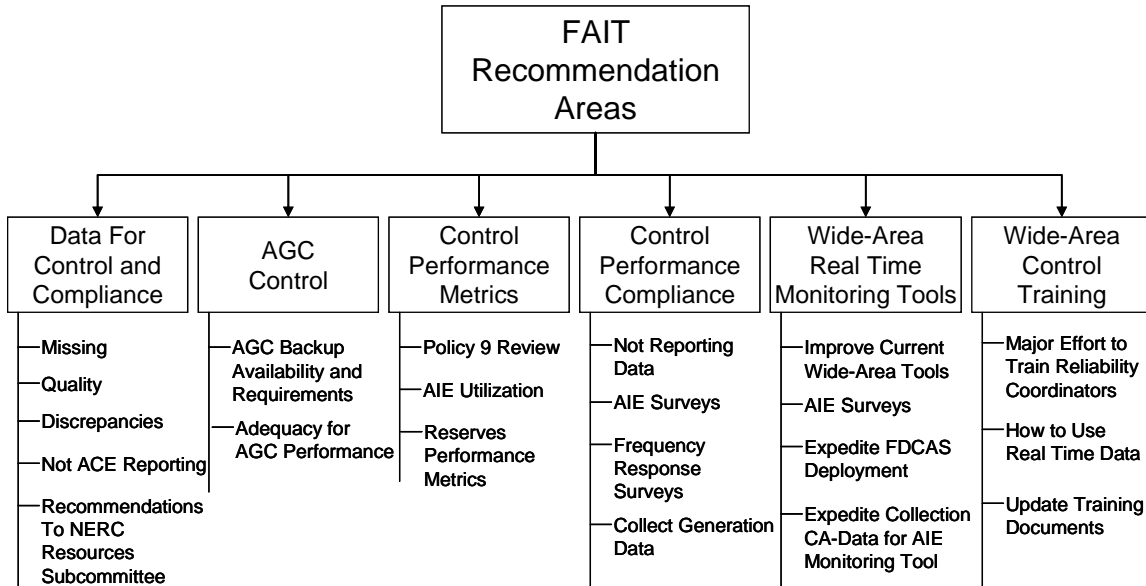
Table 5.4 — August 14 Phasors with Excursions

Period T, minute	OSIsoft's T, minute	Max Frequency Magnitude For Other Days, HZ	August 14 Frequency Magnitude, HZ	Max Approximate MW Magnitude For Other Days	August 14 Approximate MW magnitude
170.7	N/A	0.0072	0.0087	230	278
102.4	N/A	0.0039	0.0047	125	150
85.3	76.8	0.0033	0.0047	106	150
38.4	34.9	0.0029	0.0039	93	125
17.1	18.7	0.0025	0.0036	80	115
16.5	18.7	0.0026	0.0031	83	99

It can be easily seen that the incremental difference for the analyzed modes on August 14 was within 0.0015 Hz (50 MW). This incremental difference, of course, does not allow classifying the corresponding modes as specific “significant power oscillations” observed prior to the blackout.

6. Recommendation Areas and Specific Recommendations

FAIT reviewed the recommendations summarized and described here and will refine and match those recommendations with the information in the FAIT final investigation report.



FAIT Recommendations

Data for Control and Compliance

1. Data quality needs to be improved. This FAIT analysis was hampered by missing or inadequate data storage or time stamping, including the AIE surveys. A high degree of uncertainty exists on the timing of the generating unit trips and thus the calculated Eastern Interconnection frequency responses. It is unclear what other events may have occurred in the Eastern Interconnection that could have masked or modified observed sequence of events. FAIT recommends that NERC and/or the DOE expedite industry efforts to develop a standard or standards for:
 - a. Time stamping of original field data, including generator events, based on a North American time standard (GPS, IRIG, or Zulu).
 - b. Collecting generator outage data (time, MW, ramp rate, and location) and routinely analyzing impacts on interconnection frequency.
2. The RS should prepare a data request for PJM, requesting them to clarify the time discrepancies and the possible correlation between their abnormal ACE and abnormal frequency response during the period when AGC was not available on August 14. Once causes are identified, the RS should assess if actions are required.
3. The RS should propose AIE as the reference standard for a reliable ACE.

4. The RS should request detailed information for the control areas to understand the causes for the large frequency excursion hour ending 1300 (double what would be expected from the Eastlake-5 outage).
5. The RS should request frequency response survey(s) for the generator trips prior to 1600 EDT on August 14. The Handsome Lake trip is consistent with a 2,500 MW/0.1 Hz frequency response for the Eastern Interconnection, while the Piney Creek trip is consistent with a 775 MW/0.1 Hz. frequency response for the Eastern Interconnection. These circumstances would indicate that the frequency responsive resources on the Eastern Interconnection were virtually exhausted by the time of the Piney Creek trip.
6. NERC should require that control areas that do not report ACE to NERC to submit their reports to NERC.
7. NERC should request an explanation of differences between AIE schedules and IDC schedules and any impact on voltages in Ohio.
8. NERC should approve and implement the proposed frequency data analysis and storage project.
9. NERC should identify, report, and assess control areas experiencing EMS-AGC data problems on August 14.
10. NERC should publish a list of control areas that do not provide NERC with real-time data.
11. NERC should investigate the collection of real time net actual and scheduled interchange with adjacent control areas. This data will help identify “unexplained ACE” and allow an ACE calculation for each control area when their EMS is down (via a calculation using neighbors’ data).
12. The RS should institute the following requirements for pulse accumulator meters (MWh meters used for hourly accounting):
 - a. All adjacent control areas shall agree on **one** official tie-line meter.
 - b. All adjacent control areas shall agree on calibration procedures.
 - c. All adjacent control areas shall agree on meter error adjustment procedures.
 - d. All adjacent control areas shall pre-identify alternate sources of MWh readings, such as:
 - i. Integrated AGC tie line readings.
 - ii. Integrated state estimator readings.
 - iii. Redundant MWh meters.

AGC Control

1. The RS should perform a control area survey for AGC backup system, (analog and/or digital) availability, and control functionality. It should then assess the survey results and develop recommendations if required. Backup AGC should be available as a hot standby and provide indication to dispatchers on readiness to assume control. As a minimum, backup AGC should compute ACE for comparison purposes to the primary AGC.

Control Performance Metrics and Standards

1. Surveys:
 - a. Review the clarity of the instructions to prevent forms from being filled out incorrectly.
 - b. Modify the AIE NERC summary report to support more cross checks on the AIE ACE, the ten-minute AIE ACE, and the CERTS one-minute ACE.
2. Reserve Sharing:
 - a. Make sure each control area can validate changes to its NI_s with a journal feature in AGC and accounting systems.
3. NERC should expedite control area transfer of data to the AIE NERC Real-Time Monitoring application.
4. The RS should develop ways to validate the interconnection ACE:
 - a. Compared to ΣACE_{CA} .
 - b. Compared to the interconnection frequency.

Control Performance Compliance

1. The RS should issue an AIE follow-up letter with the following requests:
 - a. Request control areas to explain the difference between their AIE and ACE and specifically ask them if they lost generation or schedules during the hour. Causes for AIE-ACE difference should be assessed and recommendations developed.
 - b. Ask the control areas to explain the reasons for the ACE excursion at the beginning of hour ending 1400 resulting in sustained over-generation. Although no potential link between the analyzed extended frequency excursion and the August 14 blackout was identified, the RS should identify the reasons for the CPS2 violations in the CIN and TVA control areas.
 - c. Obtain data from control areas not providing it.
 - d. Track down the causes of other resource losses nearly coincident with the loss of Eastlake 5 (i.e., send letters to entities with AIE indicating a possible resource loss).
 - e. Get explanations from control areas with questionable ACE.
 - f. Get explanations where real-time ACE data varies from ten-minute AIE-reported ACE.
 - g. Get explanations from control areas with $AIE > L_{10}$ aggravating frequency.

Wide-Area Real-Time Monitoring Tools

1. Questions have been raised about current control performance criteria for situations where the interconnection frequency remains continuously above or below the scheduled frequency for long periods of time as happened on August 13 for close to eight hours and on August 14 for more than three hours. NERC Operating Policy 9 requests that reliability coordinators take remedial action when the interconnection frequency error is “in excess of 0.030 Hz for more than 30 minutes.” Several issues have been raised: is

- 0.030 Hz the correct threshold for all interconnections, what reliability performance is Policy 9 attempting to address, and when should the 30-minute count start and end?
2. Provide a template on reliability coordinators information system (RCIS) for collecting “unit trip” information to facilitate benchmarking of frequency response and investigation of system events.
 3. Develop a common format for data provision and an archiving requirement (or standard) to facilitate analysis and performance validation.
 4. Improve current real-time monitoring tools for reliability coordinators for monitoring ACE and frequency with requirements identified during this investigation.
 5. Provide reliability coordinators “delta flow” tools to flag and point to problems.
 6. Tune up reliability coordinator monitoring and alarm tools for unexplained delta frequency.
 7. Investigate the use of additional real-time control monitoring tools to help operators to identify normal operating conditions and unexpected operating conditions.

Wide-Area Real-Time Operations Control Training

1. Develop short and long-term plans for training reliability coordinators and security personnel in the use and analysis of operational data during emergency operating conditions.
2. Develop training documents to assist:
 - a. Reliability coordinators in identifying and tracking down frequency problems.
 - b. Control areas in meeting their balancing obligations.
3. Incorporate into training plans and documents the concept: “What is a quality ACE?”
 - a. Alert the system operator when ACE is suspect.
 - b. Show the system operator how to detect a suspicious ACE:
 - i. Real-time: check instantaneous ACE components against state estimator ACE components (or use other statistical behavior methods).
 - ii. Hourly: check pulse accumulator ACE components against integrated ACE components.
 - c. Compute a backup ACE in hot standby mode so it can be checked continuously.
 - i. Pre-identify alternate sources of tie-line telemetry.
 - ii. Assess true independence of alternate sources to prevent common mode failures.
 - d. Assess whether ACE change correlates to the expected frequency change.
 - e. Provide the same data to each control area so the system operator can observe the same information that the reliability coordinator sees. This data sharing supports better communications.

4. Incorporate into training plans and documents guidelines for good utility practice for:
 - a. Hourly accounting and error reconciliation.
 - b. Synchronization of generation ramping to transaction ramps.
 - c. Meter and telemetry design for primary and backup service.

Independent FFT Study

Frequency Analysis for August 14, 2003

By

Gary Bullock¹²

Tennessee Valley Authority

¹² By permission from Gary Bullock

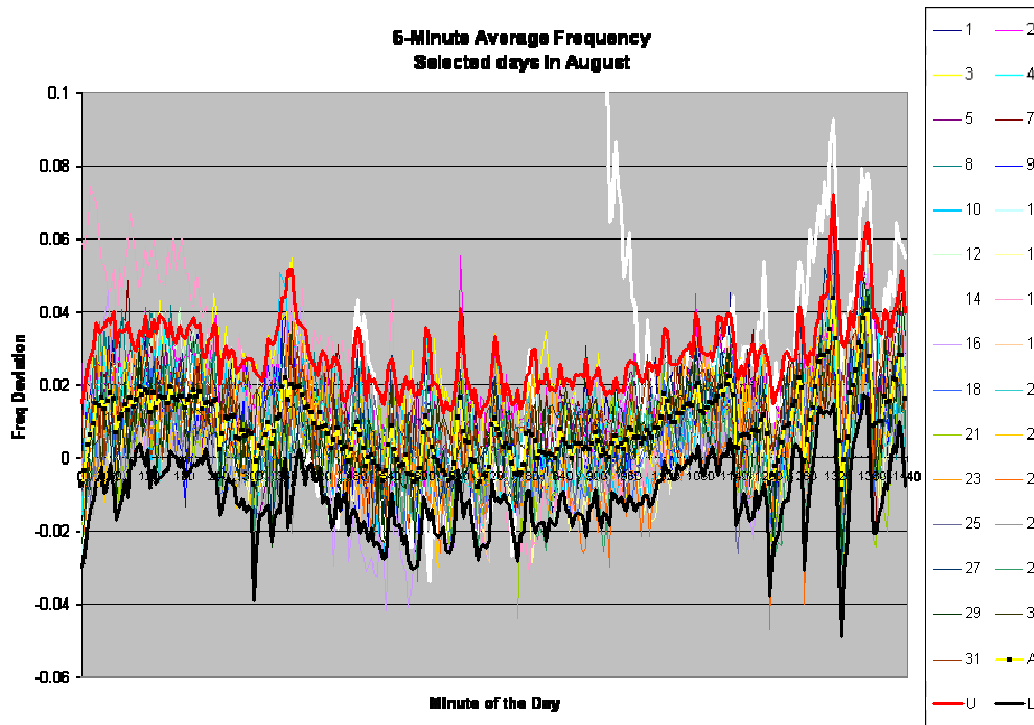
Independent FFT Study

Frequency is a one-dimensional measurement. It has limited use as an indicator without cross-correlating it to another measurement. If intra-area transfer oscillations are impacting frequency, then the regional tie flow dynamics or multi-area phasor measurements are also needed for a complete analysis. If control area schedules are not being managed, then the schedules and control area outputs are needed. If IPP generators (or generation-only control areas) are not ramping to instantaneous schedules but rather to meet integrated 30-minute or one-hour energy schedules, then individual generation imbalance measurements are needed.

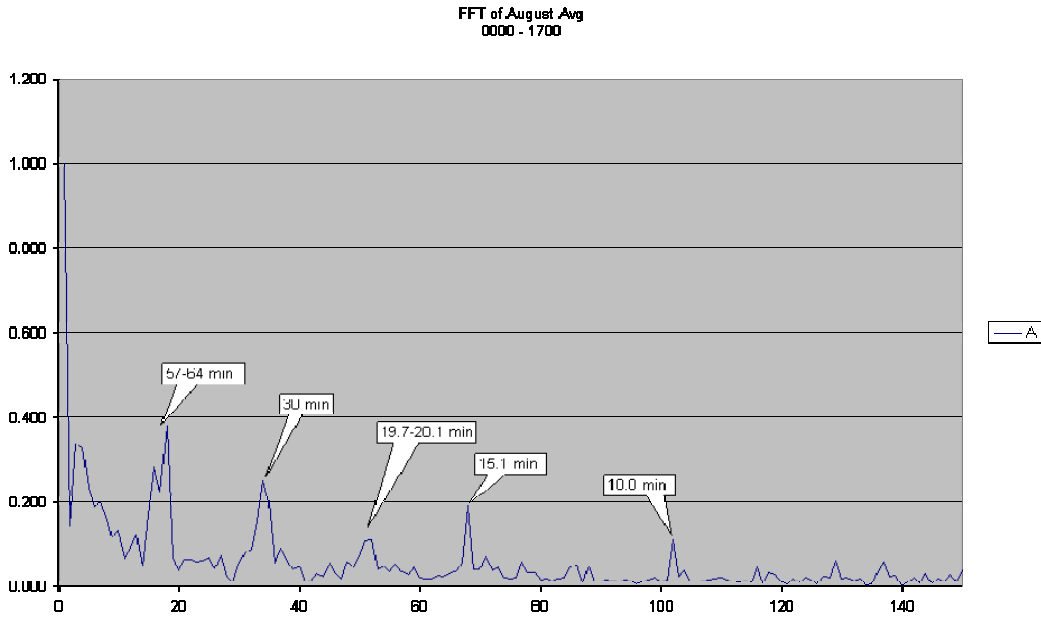
The singular analysis of system frequency is like measuring the instantaneous changing elevation of a pond at one point and trying to detect where and from what the surface ripples are coming from. Was that a big fish in the middle or did someone just open the spill gate?

In short, this analysis might be something for the Electric Power Research Institute (EPRI) to pursue, but not NERC. It will need a lot of work to produce any useful conclusions.

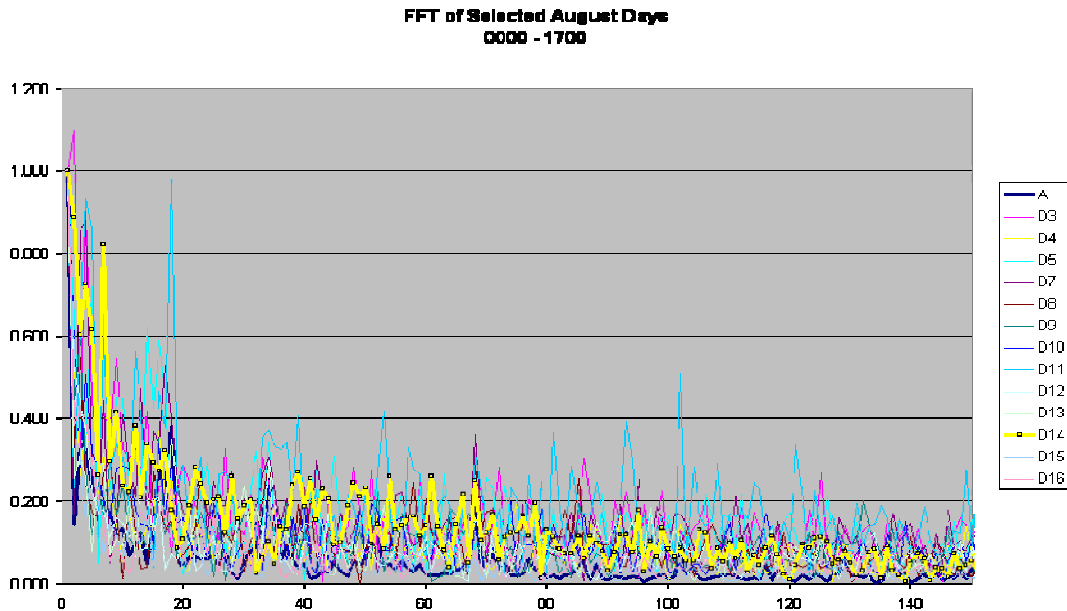
Engineers in TVA retrieved the 2-second frequency data in our archives for all of August, 2003. A couple of days (6th and 9th) had bad data, which I discarded. TVA also had a problem and lost the first several minutes of the blackout frequency data at this resolution on the 14. From the rest, I constructed daily plots on several bases. It is busy, but the first of these is a combination of 29 days of five-minute average frequency. To that I have added the average (A) and statistical high (U) and low (L) limits for a 98 percent probability. This plot is on the next page. The two most dramatic observations are: (1) Frequency deviation is not tightly controlled on the Eastern Interconnection; and (2) Definite patterns of frequency deviation movement occur on the hour. Since the graphics will be hard to see in detail, I'll send you the backup spreadsheets, too.



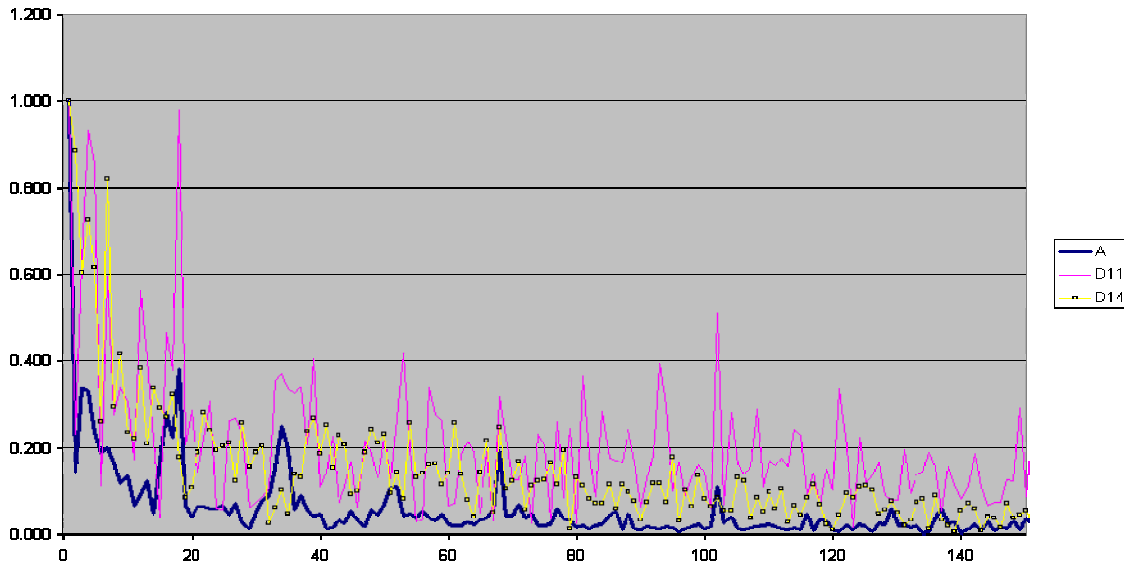
If the raw data is filtered through a one-minute average and then analyzed by FFT, a very interesting but expected result is evident. FFT analysis peaks occur for periods that match the expected problems with hour schedules and the subsequent impact on system frequency. This result is shown in the next plot.



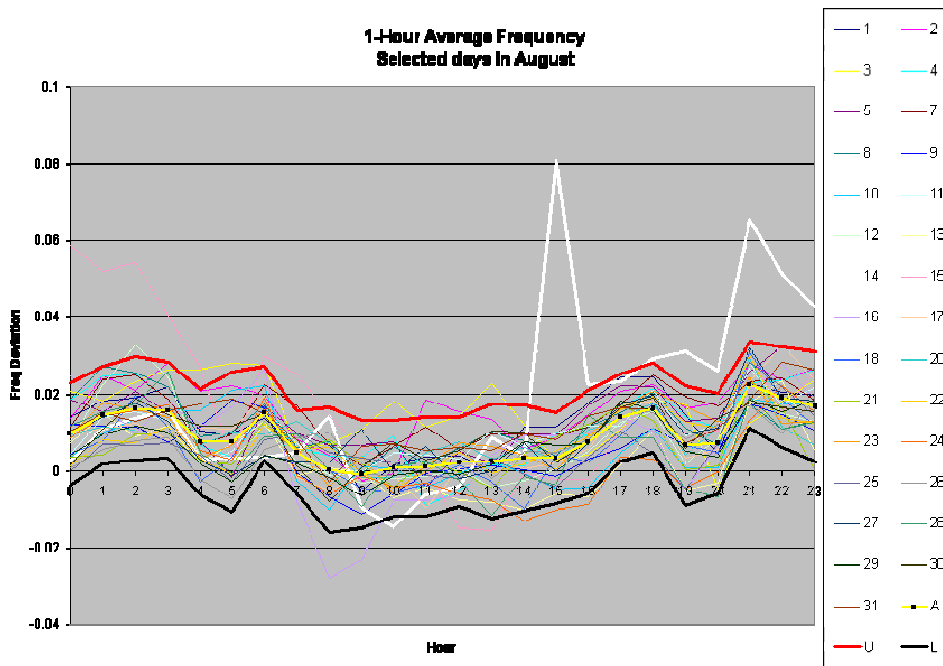
For this report, all the FFTs are performed on a 1024-point sample of one-minute average frequencies. The next step is to compare several different days in August against the back drop of the average. This comparison is done in the next plot. The dark average is seen skirting the bottom of the plots. The yellow plot with boxes is August 14. It has several elevated peaks but none I would say stand out as a predominant mode of oscillation. It is also not the worst of the group. For easier comparison, the second plot on this page shows just August 14 and August 11.



**FFT of Aug 11 and Aug 14
0000 - 1700**



In order to cover the whole spectrum, I also captured the one-hour averages for this collection of data. (This graph may be a little misleading. The deviation at “1” for example is really the one-hour average from 0100-0200 hours.) The plot below shows the effective daily pattern. We all “know” this from experience, but it is perhaps indicative of how loosely we approach frequency control on the Eastern Interconnection. The frequency deviation is nearly always high at night (turn-down problems) and stays more normal by day. You can see significant changes for the 0600–0700 and 2100–2200 time periods. These are the classical on-peak/off-peak schedule changes. You’ll also note we seem always to be averaging toward the positive. Remember, for a long time now, all time error corrections have had to be to reduce frequency to slow down the clocks.



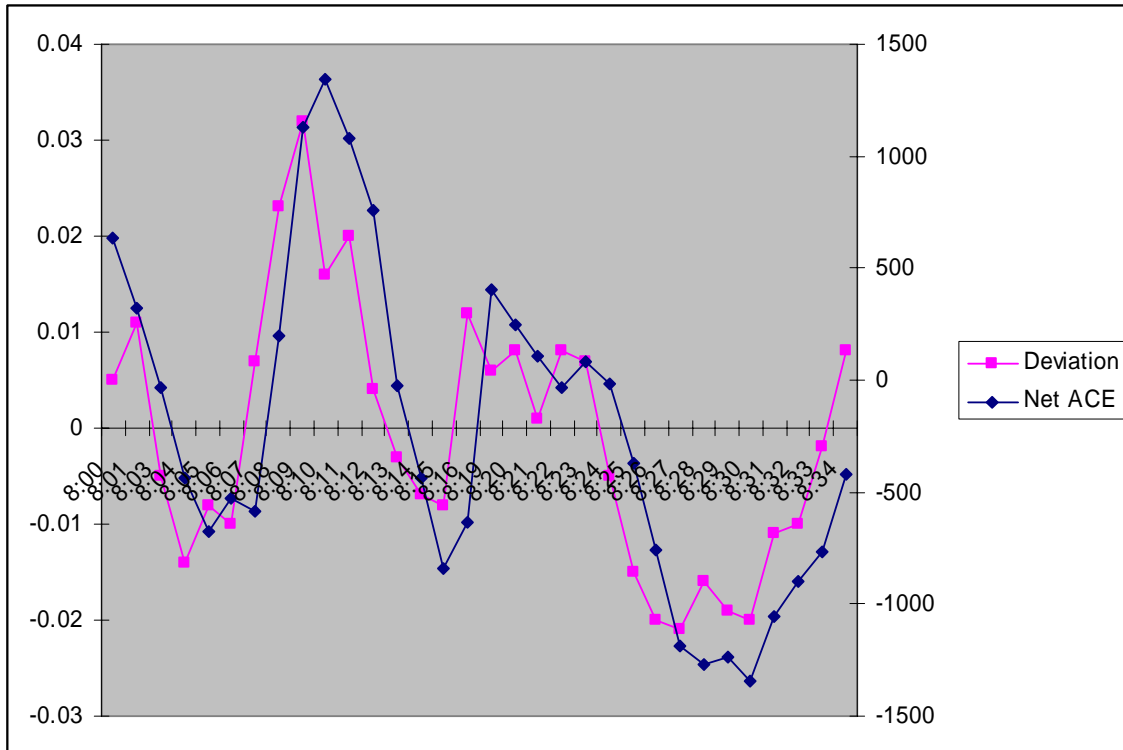
Conclusion

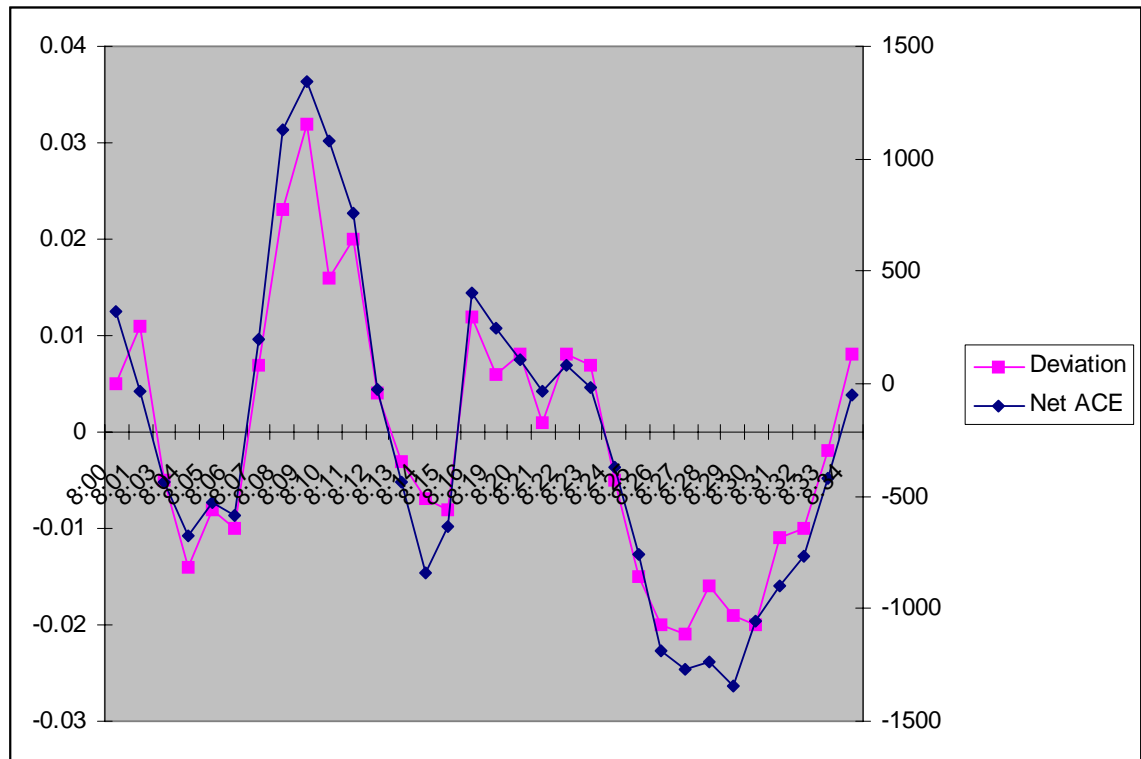
The Eastern Interconnection may not be controlling frequency close enough for the approach recommended by Dr. Wells and Mr. Russo to make sense. There are large signal impacts indicating that some attention may be needed in this area. If you recall, remaining Eastern Interconnection frequency after the blackout went and stayed too high for a long time after it was over. I have been concerned that this occurrence (and other analyses like the one contained here) indicates insufficient resources on control to maintain frequency on the system. At various times, unexplained singular frequency excursions (representing 1,000+ MW) occur on the system. In the past, they were usually the result of a lost unit. I think now, they are more likely the result of a “lost” schedule. With several such unrelated events occurring regularly, the sliding FFT approach by itself has a significant problem detecting real instability through all the noise in the frequency signal. As mentioned before, it would need to be coupled with other system-wide data like PMU (Phasor Measurement Unit) or regional tie-flow data in real time.

**Methodology to Calculate Frequency Response and Identify
“Unexplained ACE”**

Methodology to Calculate Frequency Response and Identify “Unexplained ACE”

- Sum the CERTS ACE data by minute for all control areas providing data.
- Calculate estimated EI ACE ($-6,250 * \text{frequency deviation} * 10$).
- Calculate “unexplained ACE” (EI estimated ACE – CERTS net).
- Check to see that frequency deviation time lined up with CERTS net ACE (to be sure ACE and frequency data was synchronized). There was a one-minute skew (see below).
- Shift the ACE data by one minute (see below).





Frequency Response Calculation

- Calculate the bias of CERT submitters.
- Estimate the bias for all generation-only control areas at 1 MW/0.1Hz.

5278 MW/0.1Hz	Bias for "CERTS-Reporting Control Areas
6265 MW/0.1Hz	TOTAL BIAS
84.2 percent	Percentage of Eastern Interconnection

- Exclude data after 1609 CDT as the Eastern Interconnection was no longer intact.

The median response of all one-minute averages (516 measurements) was 2,872 MW/0.1Hz. Since 84.2 percent of the EI provided ACE data, this result would imply the Eastern Interconnection frequency response was on the order of 3,410 MW/0.1 Hz.

There were only one or two events on the order of magnitude of governor dead band that would typically merit a frequency response survey.

Estimated frequency response for the control areas providing ACE data for smaller events was 2,350-2,790 MW/0.1 Hz (This estimate is based on dividing the mean frequency response by 0.842.)

Excursion Size	# of Events	Mean FR	Median FR
>+/-0.01Hz	62	2346	2259
>+/-0.015Hz	20	2134	1778
>+/-0.02Hz	7	1969	1926

Note: Several control areas were providing ACE data with a periodicity longer than one minute. This data should be considered a “low end” estimate of frequency response.

Conclusion (Frequency Response Observation)

The results of this experimental method of calculating frequency response implies that it was near or slightly below typical levels. Frequency response should be higher on high-demand days. This calculation supports the hypothesis that reserve levels were somewhat below normal.

It also supports the suspicion that there was a second generator lost on the Eastern Interconnection about the same time as the Eastlake 5 event. If this second generator were near Ohio or “downstream” of prevailing flows through Ohio, this loss would have aggravated conditions in the contingent area.

The RS should call for one-minute ACE data for the period 1230 to 1250 CDT and specifically ask if any resource was lost or any schedules were changed during this period.

Explained vs. Unexplained ACE

As noted above, the CERTS data set represents 84.2 percent of the Eastern Interconnection. The CERTS ACE data was netted in order to quantify the “known” ACE. In addition, an estimated Eastern Interconnection ACE was calculated by:

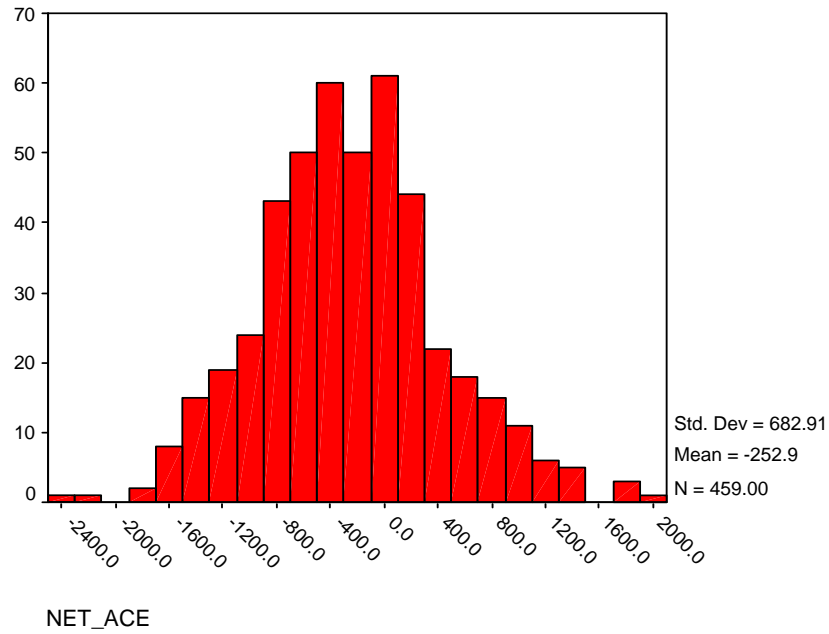
$$\text{Calculate estimated EI ACE } (-6,250 * \text{frequency deviation} * 10).$$

From this, an “unexplained ACE” was calculated (EI estimated ACE – CERTS net). This unexplained ACE has two primary components:

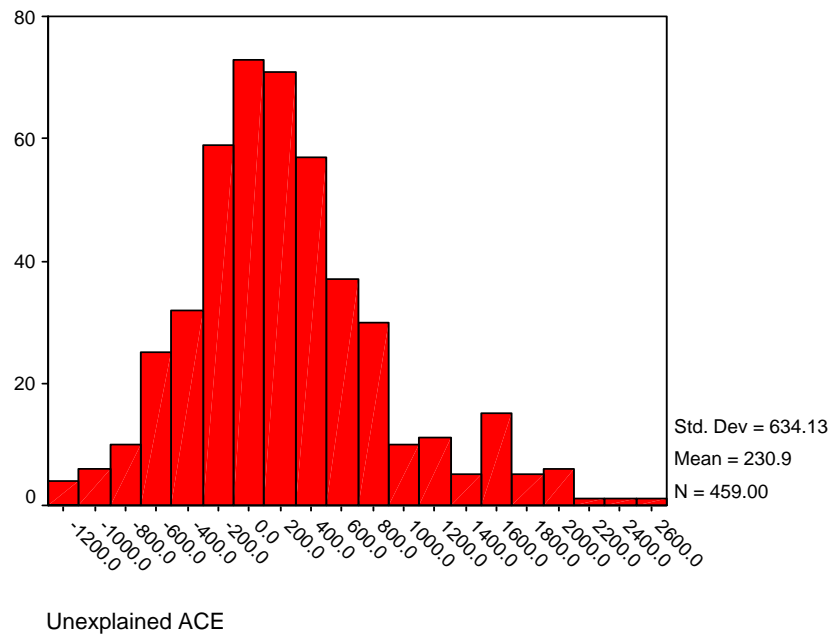
1. The net of those control areas not providing ACE data.
2. Error in the ACE data provided to CERTS.

Even though the unexplained ACE appears to account for a small subset of the Eastern Interconnection, the unexplained ACE variability was of the same magnitude as the explained ACE.

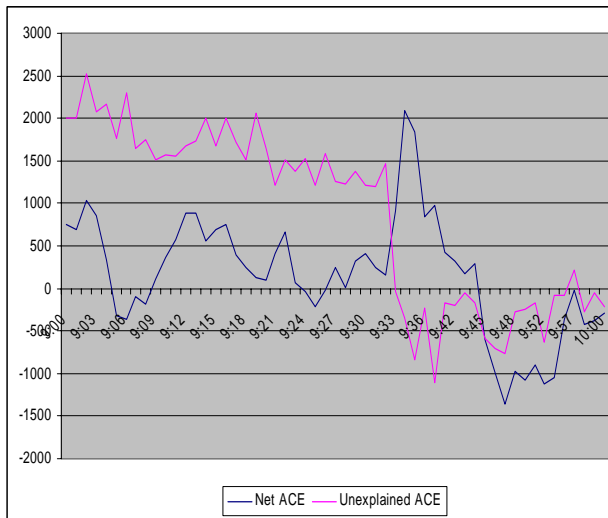
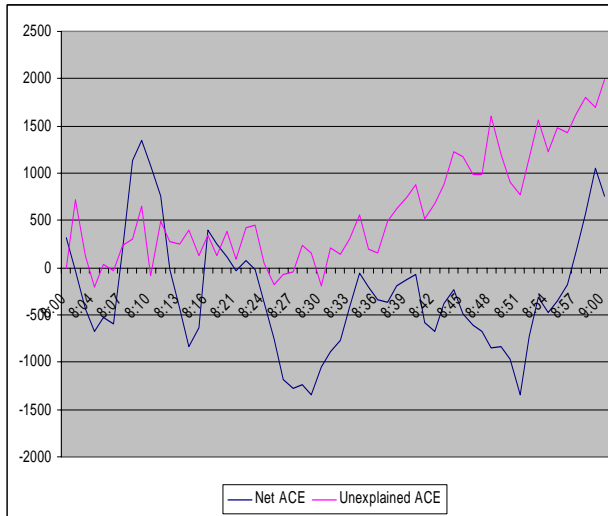
Attachment Figure 1 – “Explained ACE” (Net of Reported ACE)



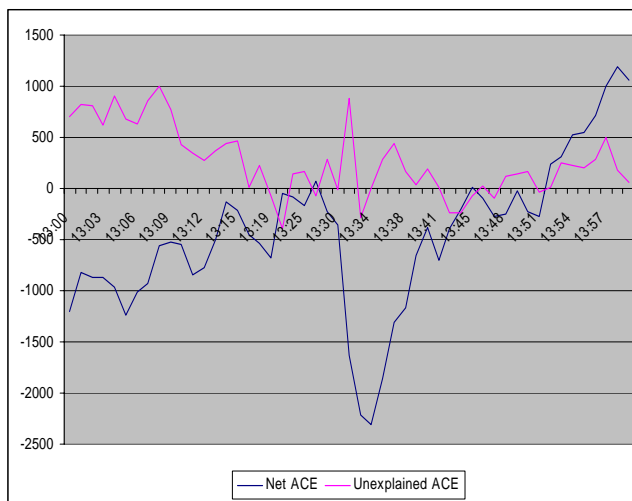
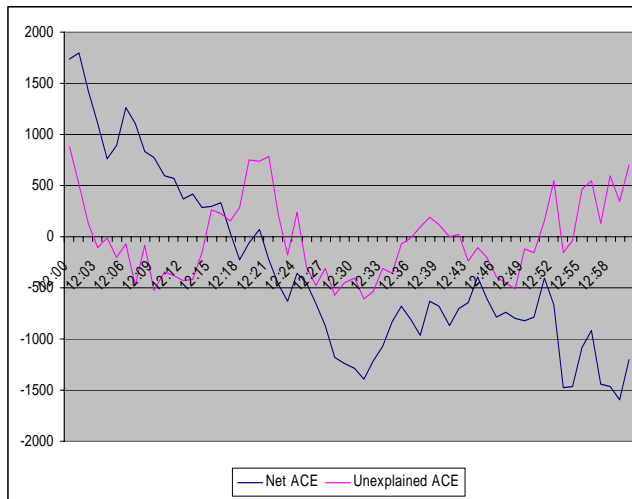
Attachment Figure 2 – “Unexplained ACE”



The following graphs plot the explained and unexplained ACE by hour for some of the abnormal frequencies analyzed.



The apparent shortfall in non-reporting areas occurred from 0825 to 0835 EDT. The apparent onset of PJM control problems occurred at 0830 EDT. (It is interesting to note that the problem lasted almost exactly one hour.)

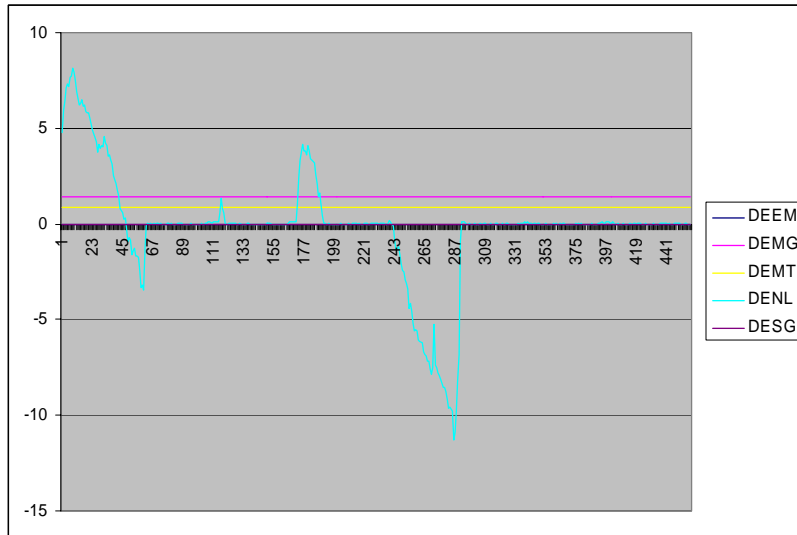


1220 “unexplained ACE” may be due to “dramatic A__” swing mentioned in AEP transcript.

This is the hour in which Eastlake 5 was lost. The ACE data should not be taken as completely accurate. It is likely there were non-simultaneous entries of reserve sharing schedules that may have skewed the “net ACE.”

Generation-only Control Areas

NERC records show there are twelve generation-only control areas (GOCA). Only five of these control areas provided AIE and ACE data. Of these five, only one provided ACE data that showed any variation (and this chart appeared “clipped”).



Even with no generation on line, a GOCA should have an ACE. In fact, such a control area could have a very large ACE if it were used as a scheduling “hub” and the schedules didn’t net to zero.

- How many GOCA’s had generation on line on August 14?
- As a side issue, are multiple control areas being operated by a single person?

Frequency-ACE Investigation Team

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