Power System Dynamics in the Eastern US-Canadian Interconnection; Some Experiences

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1.0 Introduction

The purpose of this technical document is "to summarize the power system dynamics in Eastern Interconnection (EI), based on Richard Schulz's experience." The document is prepared as part of the AEP CERTS Phasor Application R&D Project. Because of "special-purpose" nature of the document, it focuses only on several geographic portions of EI and technical aspects of EI power system dynamics. Due to the scope of the assignment, some topics are covered in more depth, while others in less depth. Nevertheless, the document captures decades of experience gained by the author, which would be useful to the EI community in developing better understanding of EI power system dynamics. The contents of this document focus on power system performance aspects, and therefore, its distribution should be limited to personnel involved with the Transmission Reliability function.

2.0 "0.4 Hz." Oscillatory Mode

2.1 Initial Discovery

The 0.4 Hz mode was first observed at AEP in on October 5, 1991, shortly after June 1991 when the first AEP PMU was put into service in the Marysville 765 kV station control house. AEP people knew of a generation trip at the Rockport plant, and, using data from the Marysville Phasor Monitoring Unit (PMU), we plotted the Marysville frequency over 5 minutes, centered on reported time of the trip. The recording had evidence of a sustained 0.4 Hz, component, having a value of about 2 mHz. {peak-peak} before the trip and approximately 5 mHz. after the trip. This is shown in Fig. 2.1.1

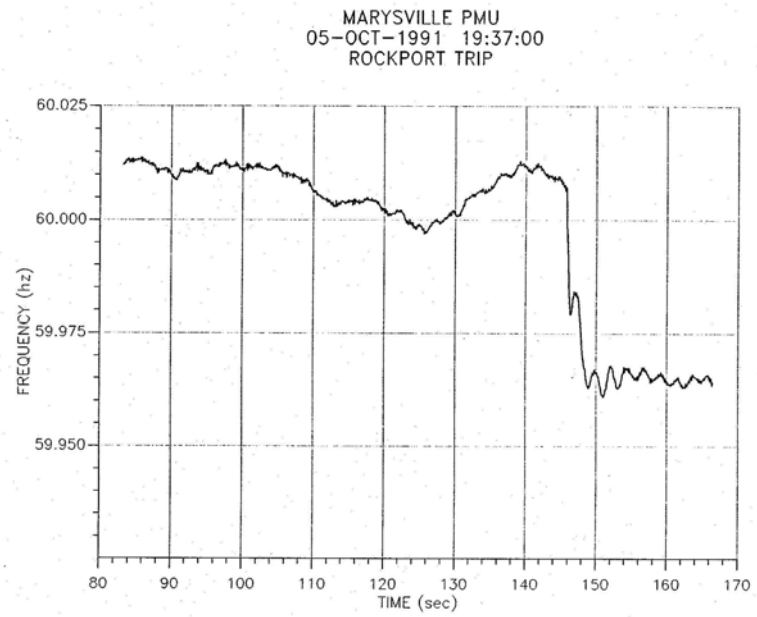


Fig. 2.1.1 Frequency plot – First Discovery of 0.4 Hz. Mode

Subsequently we made Prony analyses of these data, which confirmed the presence of an undamped mode at 0.4 Hz. both before and after the trip. On that day the modal frequency was within the range of 0.395-0.495 Hz.; in later events, somewhat higher frequencies (shorter periods) were found (¶2.4 below). I know of no earlier discovery of this mode in the Eastern US-Canadian Interconnection (EI).

The plot of the power flow from Marysville to Dumont more clearly shows a sustained 0.4 Hz. component before the trip; see Fig. 2.1.2. The size of the power swings after the trip, Fig. 2.1.3, is not much greater. In both figures, the Y coordinate units are hundreds of MW.

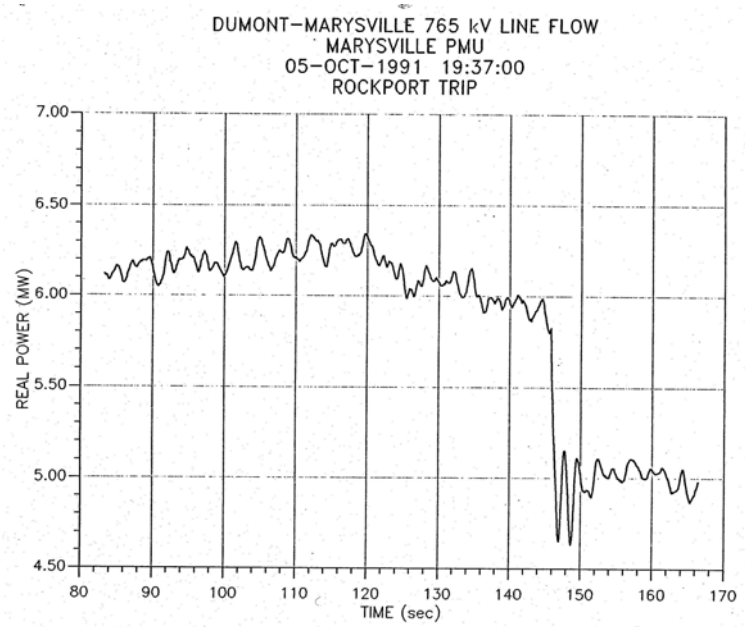


Fig. 2.1.2 Power Flow Plot – First Discovery of 0.4 Hz. Mode

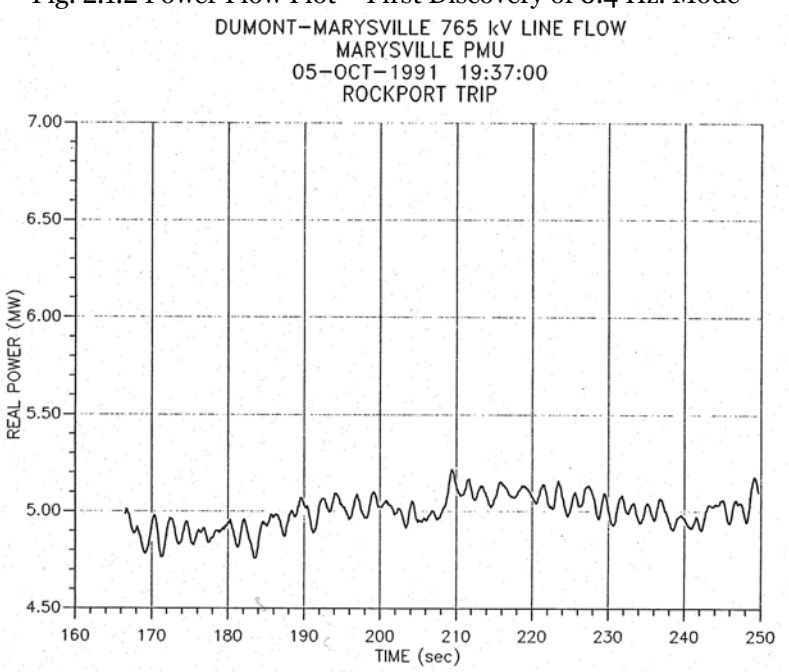


Fig. 2.1.3 Power Flow After Trip – First Discovery of 0.4 Hz. Mode

There were negligible 0.4 Hz. swings in the voltage at the Marysville station.

2.2 Analysis work by NPCC COSS-2

In the same time period, the Northeast Power Coordinating Council (NPCC) had a Working Group formed jointly between Operations and System Studies, COSS-2. COSS-2 was tasked to investigate what they called interarea oscillations, meaning among the synchronous Areas of NPCC: Maritimes, New England, and New York. Because the work of the earlier COSS-1 working group had found oscillations [COSS-1 1989] [1] with modes that affected other reliability areas beyond NPCC, COSS-2 had members from ECAR and PJM initially, and added members from VACAR and SERC during its work.

The tools available to COSS-2 included simulation models, including conventional "stability" simulation programs, dynamics analyses tools, and event dynamics recorders including frequency recorders (known as MDFRs) installed in Ontario and Michigan, AEP PMUs, and a MehtaTech dynamics recorder installed at Northfield Mountain, Massachusetts. None of these recorders then had capability to recognize oscillations. An MDFR would be triggered by a rapid change in the frequency of the PT secondary voltage, and record 30 seconds of frequency data with 5 seconds before the trigger and 25 seconds after. It recorded frequency 10 times a second. These 300 data points were stored in the MDFR and could be polled by computer-driven software to download the data by modem and leased phone line. AEP's PMUs used event notification software in its host computer to alert the analysts to examine the event; the initial software would detect losses of generation and load. Later the event detection software included the ability to provide alerts for sustained oscillations of several parameters, including power, bus voltage and the frequency of bus voltages. [Laios, Schulz 1995], [Schulz, Laios, 1997]

With these tools, COSS members and others with EI monitors routinely used email to exchange information and commentary about the dynamic response of the system to events, and the COSS meeting agendas included discussion of recent system responses as seen at several EI locations. COSS made analyses for model validation through event re-construction. There were several analyses of staged events made during equipment commissioning, including the full load rejection of the Darlington G2 nuclear unit (1101 MVA) and a trip and restart of the Sandy Pond HVDC terminal. These results are reported elsewhere [COSS-2 1994] and not discussed further here.

2.2.1 May 6, 1992 Rockport event exhibited 0.4 Hz. mode

On May 6, 1992, a 1300 MW coal-fired unit at Rockport, Indiana tripped from the 765 kV system. As in the Oct. 5, 1991 event, the system response to the trip had poorly damped 0.4 Hz. oscillations on the interconnected system. At its next meeting, COSS chose to attempt using this event for another analysis for model validation through event re-construction. In all the simulations of the May 6, 1992 Rockport event, as in the Darlington re-construction, the analysis found that the initial governing response was much more optimistic than in the recordings; this is discussed below, section 4. The initial simulation of the May 6, 1992 Rockport event found oscillatory responses with a fair match to the period of the recorded 0.4 Hz. oscillations. However, the damping of

[1] References are listed at the end of the document. They are noted within square brackets. They are listed alphabetically, and include the person/group author and, year.

the initial simulation did not match the recordings; the simulation slightly overestimated damping.

2.2.2 Improved Dynamic Models of the May 6, 1992 Rockport event

By experience, COSS-2 knew that the initial dispatch (generation dispatch, load levels, and interchanges) used in the simulation affects modal damping. COSS collected dispatch condition data for the time of the May 6, 1992 Rockport event: first from COSS members. The first simulations were made with "off the shelf" dispatch for non-COSS areas; these had 'only fair' matches to the modes and mode damping in the event records, noted at the end of the prior paragraph. The ability to match the recorded power system response, and particularly the recorded modal period and transient mode shape was found to improve as the data for the power system operating conditions (load level, generation dispatch, interchange levels) was collected from greater geographic range within the eastern interconnection. Pre-event system conditions were gathered from a much wider area for the Rockport test (from NPCC, MAAC, ECAR, CARVA, SERC, and a large part of MAIN), than for the Darlington test analysis. More dynamic recordings of sufficient resolution to validate simulation results were obtained. As expected, the working group's ability to simulate an event improved.

In an attempt to model the difference between simulated and recorded post-trip steady state frequency, simulations were also made with data that increased governor droop; this change made the units less responsive to changes in frequency. Increasing the droop of all governors by a factor of 4 (from 5% droop to 20% droop) aligned simulated and observed steady state frequency deviation. However, the increased droop used in the simulation made the system much less damped than the recorded response. [COSS-2 1994b]

2.2.3 Analysis with MASS and PEALS; Resulting Mode Shapes

COSS-2 participants then employed by Ontario Hydro used the MASS, DYNRED and PEALS tools that they had developed for EPRI, and Prony analyses to examine the results of the several events considered by COSS, including the May 6 1992 event.

Analyses were made with the full simulation model using two programs. MASS was used to determine mode frequencies, or eigenvalues. Then the mode tracing tool PEALS determined the participation of units, i.e. approximate eigenvectors. The particular mode shape for the 0.4 Hz mode is shown in Fig. 2.2.3.1; it encompasses almost the entire EI. The responses of SPP, Florida and MAPP are uncertain, since the modeling was based on "off the shelf"" initial dispatches, adjusted for the interchanges that resulted from dispatch data of the rest of the EI.

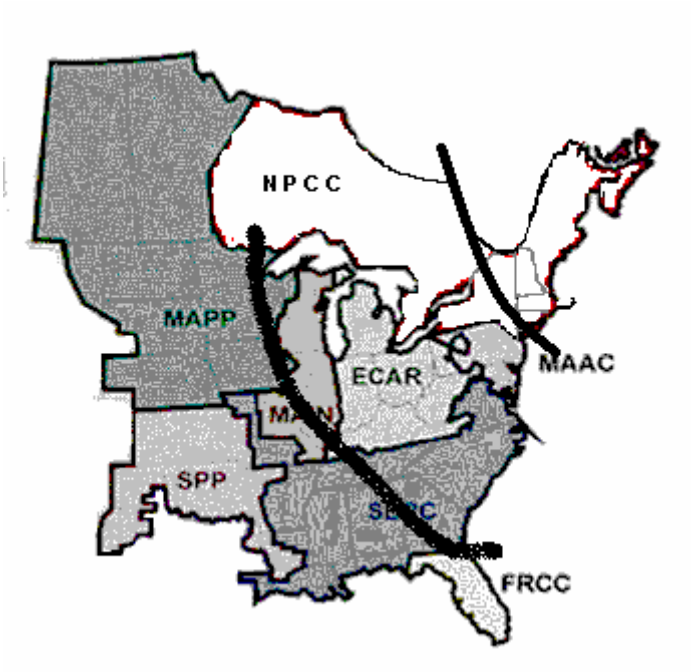


Fig. 2.2.3.1 Mode shape for 0.4 Hz. mode, from the detailed simulation model

In this mode shape figure, Quebec is not included, since it is not synchronized with the EI. Figure 2.2.3.1 shows three areas in which generators swing coherently at the 0.4 Hz. mode. These areas are separated by the heavy lines. The area including New England swings in phase with the area including SPP; these swing coherently against the area including MACC and ECAR. The heavy boundary line running through New York is less fuzzy than the other mode boundary line, since it is the more certain boundary; this is the result of having poorer modeling data for the part of the EI west of the Mississippi.

At the time of the May 6 event, the tie between New England and the Maritime Provinces was out of service. Additional analyses showed that restoring this tie would have increased damping.

2.3 Further Observations

In the time after the COSS work, many of the people who had been involved, including AEP, continued observing the 0.4 Hz. mode in some the system dynamics records. There were both informal discussions and event record data exchanges among these people. These results obtained:

- In AEP, the largest recorded swings of power at the 0.4 Hz. mode were 70 MW peak-peak on 765 kV lines. (At that time, all of AEP's monitors were at 765 kV transmission stations.) These were deemed to be sufficiently small that we should continue 'watchful waiting' of recordings, should continue informal dialogs within the transmission operations and planning community, and should undertake no analytical examination of the 0.4 Hz. mode. The watchful waiting would be attentive to growth in the observed power swings on the AEP lines; if the 0.4 Hz. mode swings became larger, then this virtual policy would be re-examined.
- Within the informal discussions, there was only one hypothesized answer to "Under what conditions does the 0.4 Hz. mode shift from adequate damping to inadequate damping, as determined by the persistence or non-persistence of the mode in the

recordings?" The analyses described above noted a correlation between poor damping of the 0.4 Hz. mode and in-service operation of the Maine-New Brunswick line (Orrington-Keswick). To my knowledge, there were no further examinations of this hypothesis, analytically or by logging of observations.

2.4 Recent Re-discovery

John Hauer, of the DOE Pacific National Laboratory, has been working with AEP recently, largely funded by DOE's 'WAMS Outreach' program. As a part of that DOE program and as part of CERTS work, he has provided support to AEP work in using power system dynamics monitors. Hauer's analyses of EI dynamics, made of an hour of AEP PMU data from Dec. 2002, provided further evidence of the 0.4 Hz. mode. Figure 2.4.1, is taken directly from Hauer's report [Hauer 2003]; similarly plots from other AEP and Ameren dynamics monitors show similarly peaks and valleys; these confirm the mode shape shown in Fig. 2.2.3.1

More recently, John made similar but more extensive analyses of the EI modes in the period immediately preceding and following the Aug. 14 2003 blackout. These analyses provide 'waterfall' illustrations of the growth and decay of the 0.4 Hz. mode period, and of the changes in damping of that and other modes.

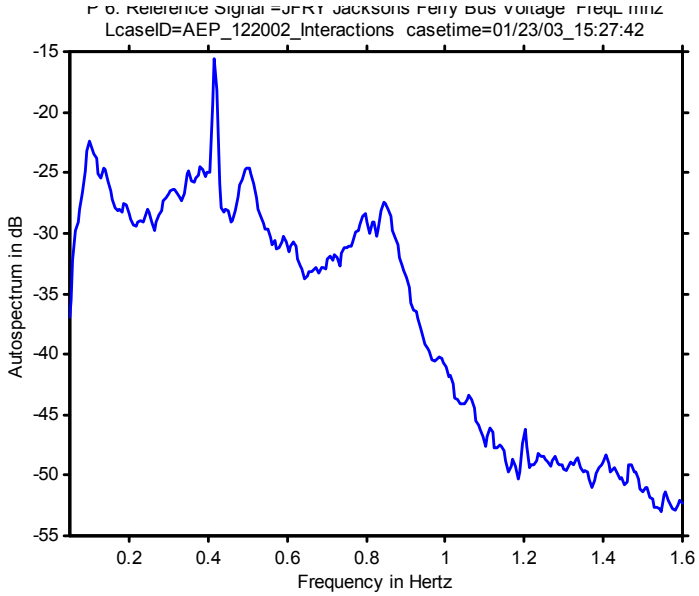


Fig. 2.4.1 Autospectrum for frequency variations at AEP Jackson's Ferry (signals processed through [0.1 1.5] Hz bandpass filter) - AEP PMU records Collected on December 20, 2002'

[Hauer 2003] presents analyses of recorders in TVA, Entergy, and AEP in Fig. 2.4.2, a waterfall plot of energy content (vertically) against frequency (left to right) and time of the record (from front to back) using the same source data as Fig. 2.4.1. The 0.4 Hz. mode seen in Fig. 2.4.1 shows up here also. In Fig. 2.4.3, a similar waterfall diagram is presented for the period of 12:00 to 16:10 EDT on August 14, 2003; there is an evident shift in the 0.4 Hz. mode; at 12:00 that day, the mode period is shorter than the 2.5 seconds that is seen in Fig. 2.4.2, implying greater stiffness in the system. At about 2:00 that afternoon, the mode frequency has shifted to 0.40 Hz., a weakening of the system, and there is a less stiff system) as time approaches the 4:10 breakup (the back of the figure). John is not certain about the correlation of these mode shifts to the events of that day; I was not privy to the blackout analyses and can not offer more insight.

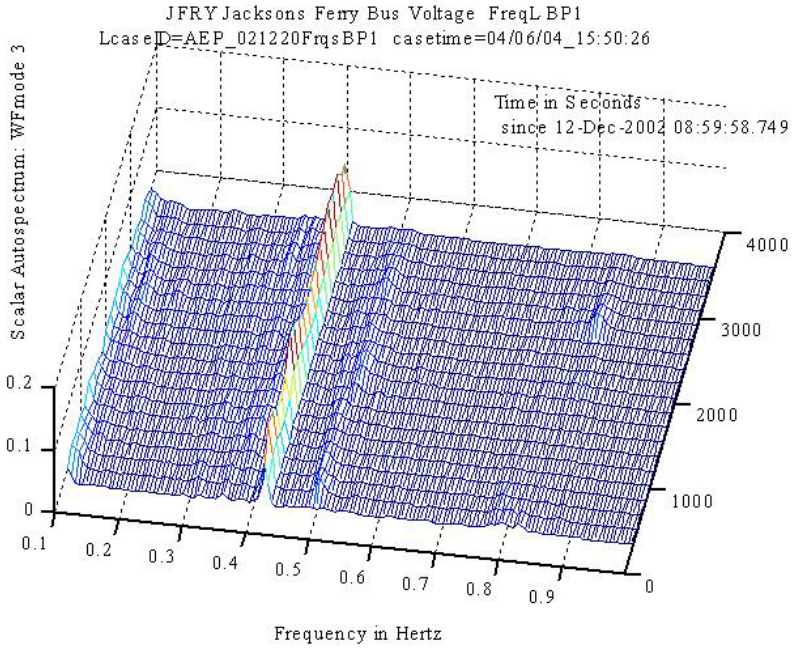


Fig. 2.4.2 Waterfall plot of Jackson's Ferry frequency scalar energy vs. time and frequency, December 20, 2003, from [Hauer 2003]

Fig. 2.4.3 Waterfall plot of Jackson's Ferry frequency scalar energy vs. time and frequency, August 14, 2003 up to point of NE island, from [Hauer 2004]

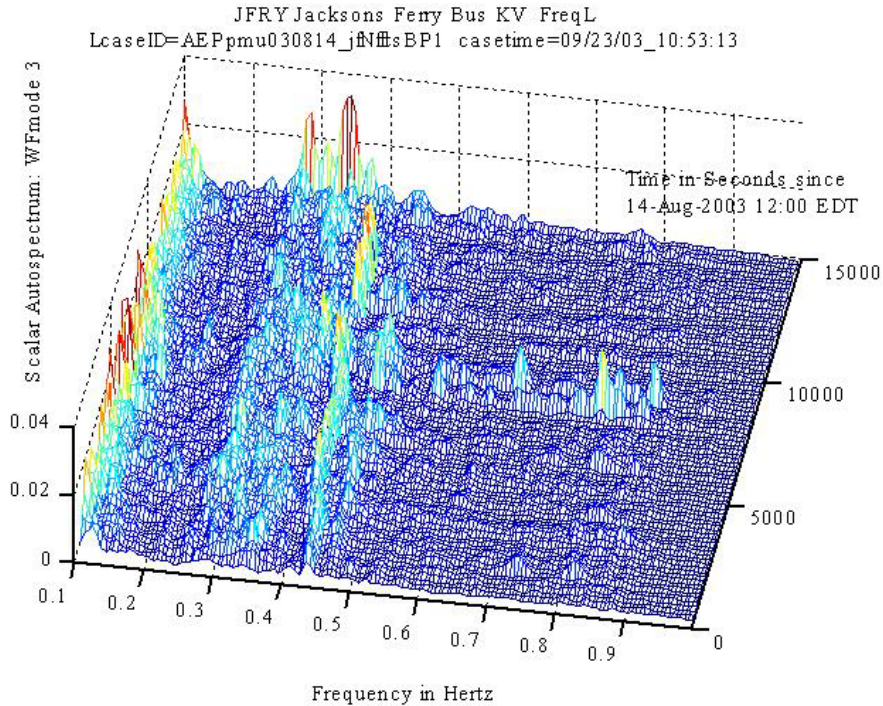
2.5 Lessons Learned

The 0.4 Hz. oscillation mode has been around for more than a decade. Usually it is well enough damped to not be evident. That is, the damping of the 0.4 Hz. oscillation mode changes from time to time, even to the point where the mode persists for hours. The reasons for these damping changes are not known.

The damping of the 0.4 Hz. oscillation mode has not been seen to be great enough to cause power swings great enough to limit operations.

The best estimate of the modal shape of the 0.4 Hz. oscillation mode encompasses almost the entire EI; see figure 2.2.3.1. The responses of SPP, Florida and MAPP are uncertain, since the modeling was based on "off the shelf" initial dispatches, adjusted for the interchanges that resulted from dispatch data of the rest of the EI.

When attempting to reconstruct an event by simulation, it is critical to have good



information about the entire interconnections initial conditions, including generation dispatch, load levels, interchanges, and generation and transmission outages. This may not be sufficient, but it is necessary.

Analyses of oscillatory modes have been made by two basically different approaches, each with good effect:

- Eigenanalyses of models, and;
- Analyses of recorded dynamics information in time and frequency domains.

Examples of oscillatory mode analyses are given in ¶ 2.2.3 and 2.4. Current texts that discuss these tools and their applications are [Rogers, 1999] and [IEEE 1994].

3.0 Other Experiences with Oscillatory Instability in the Eastern Interconnection

3.1 Oscillatory Modes near 0.8 Hz.

In the investigations using the linearized dynamic equivalents, ¶ 2.2.3, there were several modes found with periods near the 0.8 Hz. peaks found in Hauer's spectral analyses, Figs. 2.4.1 through 2.4.3. It may be reasonable to speculate that these are existing modes within the EI that have not been studied since they have not been found to be limiting transmission system operations.

3.2 Single Unit Oscillatory or Plant Instability

When individual units exhibit local oscillatory swings, i.e. swings of the unit and/or plant against the system, the consequent oscillations can be detected at some distance. In some fairly rare cases, there have been reports that these local swing modes can excite other units to have sympathetic oscillations. Two instances are discussed below. In addition, similar events have happened at the Bath County Pumped Storage Plant in Virginia, at Seabrook in New Hampshire, and other unpublished events.

3.2.1 Single Unit or Plant Oscillatory Instability – Conesville 345 kV units: Nov. 2, 1985

On that day, one of three 345 kV lines transmission lines from the AEP Conesville station was out of service. Another line tripped, and the three Conesville units connected at 345 kV experienced large power swings. Conesville unit 4 reported swings ranging up to ±115 MW, which continued for several minutes until a second line from the station was reclosed manually. There were reports from New Jersey of sympathetic swings of the same period (approximately 1.1 seconds) at the same time

3.2.2 Single Unit Oscillatory Instability - Sequoyah unit 1, December 25.1995

On that Monday Christmas morning, a persistent oscillation was seen by the Phasor Monitoring Unit (PMU) on the Rockport 765 kV bus that began about 07:11:30 EST and continued until 07:13:28. The oscillations were seen principally in the recorded frequency and power at Rockport, with a period of about one cycle in 1.4 seconds. The Rockport-Sullivan power swings were about 15 MW peak-peak, not very large. The Rockport frequency swings sizes were 3.3 milli-Hz peak-to-peak, centered on an average frequency of 59.992 Hz.

At 07:13:28 Sequoyah unit 1 was tripped manually, a turbine trip; the 35 mHz. frequency drop indicates about 1000 MW of generation tripped. The oscillations, described above, stopped at the time of the unit trip. The likely cause of the oscillations was excitation system/voltage regulator problems reported verbally by TVA people. There

were several other following records. Rockport 765 kV voltage rose by .25% at 07:13:55, apparently not associated with any thing else. That voltage did not participate much in the oscillations from 07:11:30 to 07:13:28, although a small variation (less than 0.1% peak to peak) is visible at the oscillatory frequency. At about 07:14:45 there is a small frequency step up that resembles a trip of a pumping unit.

3.2.3 Conclusions - Single Unit or Plant Oscillatory Instability

These single unit oscillatory or plant instability events are rare. They confirm that exciters and regulators can drive units into power swings that can be felt at some distance away on the network, and that event detectors will see them. But the impact is slight outside that plant.

4.0 Large Interconnected Power System Response to Generation Governing

4.1 Problem statement

Experience in the US-Canadian interconnected system shows that primary frequency control (often called governing control) is generally less effective than expected. This experience was formalized and reviewed in an EPRI project [EPRI-EPIC 1992]. Generally, this experience indicates that governing response, as indicated by the prompt change in power system frequency following loss of a unit or of an export, has about 25% to 33% of the expected governing "gain" or 1/R that is expected. On the Eastern US-Canadian interconnection, experience shows a frequency dip of approximately 0.03 Hz following loss of a unit that had been generating 1200 MW; this is commonly stated as a governing response of 4000 MW/0.1 Hz. The expected governing response would be greater, approximately 12,000 to 15,000 MW/0.1 Hz, if all units in that interconnection were governing with the standard 5% droop setting.

Other large interconnections world-wide report essentially similar experience.

From the operations side, this issue has been addressed concurrently by NERC. Personnel in the system operating components of utilities conduct 'regulation tests' that are initiated by and coordinated by the NERC Operations Subcommittee, now called the NERC Resources Subcommittee Frequency Task Force. They have reached a broad consensus that approximately one-third to one-quarter of the expected governing response is found in analyses of the recorded power system frequency.

From the planning side, the problem is this: power system analysts, using conventional transient stability program methods for simulating interconnected electric utility system response, are consistently unable to replicate the recorded response of the power system to loss of a unit and its megawatt output . The problem is the same, qualitatively and quantitatively, from both perspectives.

The problem is illustrated by Fig. 4.2.1, from simulation of a unit trip in the EI to a simulation that was made with data carefully collected to obtain a good match to the recordings that had been made across several NERC regions. (¶2.2.1, 2.2.2)

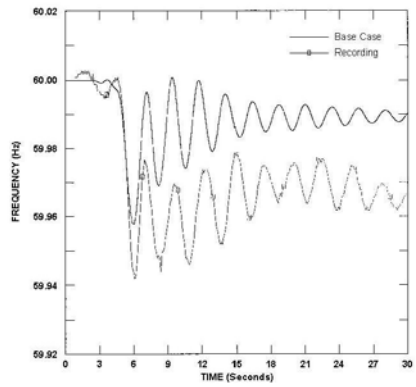


Figure 4.2.1 Event Record vs. Simulation 1

4.2 Some History

4.2.1 Observations of location(s) with governing response at 5%

In examinations made in the mid-1990s of the individual AEP-East generating unit responses and of the composite AEP-East responses to several unit trip incidents (from AEP recordings), we concluded that AEP-east then had an aggregate response of about 15% to 20 % droop. In other words, AEP-East response appeared to be essentially the same as the response of the entire EI.

At the same time. we asked for and received charts of the changes in the tie-flow changes from Florida peninsular to Georgia. These indicated that the peninsular Florida utilities had sufficient governing reserve on enough of their generation to obtain an effective 'peninsular Florida system' droop of 5%.

4.2.2 Conjectures of other location(s) with governing response at 5%

Based on the results discussed in ¶4.2.1, above, it appears that areas that are weakly tied to a larger interconnection, such as Alberta and the Canadian Maritimes, tend to accept the costs of maintaining both governing margin and governing response, based upon the likelihood of having to use good primary governing response in the face of their high likelihood of becoming islanded. These are management decisions, based on the trade-offs of theses elements:

1) $ costs of good generation governing vs.
2) $ costs of too-frequent load shedding and/or blackouts following loss of synchronism with the larger interconnection vs.
3) $ benefits of economic power and energy interchange. The likelihood of 2) increases as the power/energy interchange increases.

It is clear that the ultimate customer's costs to the generator (or vertically integrated utility) are difficult to evaluate unless there is a contractual requirement placed upon the independent generation supplier(s) by the transmission/system operator.

4.3 Recent and Current Activities in Power System Response to Generation Governing

There have been continuing efforts in this area, including CIGRE and IEEE. CIGRE Task Force 38-02-14 prepared [CIGRE TF 1999], which goes into the more difficult area of governing response in the severe off-nominal frequency conditions that accompany

islanding. That work was presented in an all-day IEEE Power Engineering Society panel session in 1999, "Symposium on Frequency Control Requirements, Trends and Challenges in the New Utility Environment". Several other authors presented their information and views there; the reader should look these up for more information.

After that panel session, I formed the IEEE Task Force on Large Interconnected Power System Response to Generation Governing, which is gathering experience and information to prepare a report. [IEEE Task Force 2005]

5.0 Some Dynamics Results not found in Power Systems Textbooks

5.1 "Steady state"

People who have been trained in dynamics by using simulation, and people who have been trained in system operation with SCADA presentations are frequently surprised by the natural noisiness that is seen in recordings of voltage, power, etc. made with recorders having a bandwidth of more than a few Hz. Figures 2.1.1 and 2.1.2 are excellent examples of this – they were prepared by IT people who had been working in system operations, and they were amazed that I was so excited with the oscillations evident in the recordings. They were familiar with time recordings SCADA results, which necessarily use anti-aliasing filters that block all dynamics with a bandwidth higher than a few tenths of a Hertz. Similarly, in presenting field use results of a monitor [Vu, et al. 1999] one person asked, "Which is the simulation and which is the recording?" to which I replied, "the simulations are smooth, and the recordings are noisy". Then the session chair replied, "Obviously you are only familiar with simulations – the steady traces are the simulation – simulations don't include the persistent changes that occur on the real transmission system".

5.2 Sweet spot" response

"Sweet spot" response - effect of fault-trip-reclose impulse as the location of the impulse is moved; result of phase alignment of several mode's responses. In the mid-1980s a multi-utility planning review was done by simulating the same fault (a stub 3-phase fault, cleared in a time longer than the primary relaying time), at each bus along a principal EHV corridor extending across the utilities' area. The planners found that most of the simulation faults were stable and unremarkable except for a few buses near a particular bus near the center of the corridor. At that particular bus, the power flow response had a strange 3000 to 4000 MW swing that began about 5 seconds of otherwise usual swings. Faults at other buses near that particular bus had similar but lesser strange MW swings.

The planners approached us (two people in GE at that time) with the request: "Is this response credible? Please make a study of these simulations and the data but *WITHOUT MAKING ANOTHER FULL SCALE SIMULATION*" The planners would only provide paper copies of the data. We first reviewed the data, which had only a few minor strange data items, proven to NOT be the 'problem' when the planners reran the cases with that data changed.

The underlying cause of the strange response was found to be a local oscillatory mode frequency that was related to larger area mode frequencies by a ratio of 4:2:1. These modes were present in the system responses for each of the fault simulations; the reason that faults at or near a particular bus resulted in a delayed large swing comes from the zeros of the indicial response. At that particular bus, the zeros of the system response

were so aligned that the system had a response similar to that of a Padé approximation to a pure time delay. See ¶5.3.

5.3 Creating and examining small system models (4 bus and 48 bus models of entire EI) to understand phenomena

Ability to create and examine small system models (4 bus and 48 bus models of entire EI) to understand the dynamics of the situation in ¶5.2, above. In that study, the reviewers made two very small models of the entire Eastern Interconnection (EI). The first model had 48 machines in a model of the northeastern part of the EI. It is described in ¶8.4 of [Chow-1982]. This model was able to reproduce the 'strange' responses found in that full-scale model, used by the planners. A 4 bus model of the EI, created to create the 4:2:1 ratio between local area modes and the larger area modes was created to support the conclusion of the underlying mode. The planners have not released the report of this work; I do not know if they would now release it.

5.4 "Zippers" or "Gaps"

There are "zippers" or "gaps", that is, loci within the Interconnection that have relatively few transmission paths that cross them. Of course, some of these are natural, such as large lakes, the Grand Canyon, and so on. There are other zippers or gaps, usually well known to people in transmission operations. There appears to be no common name for them.

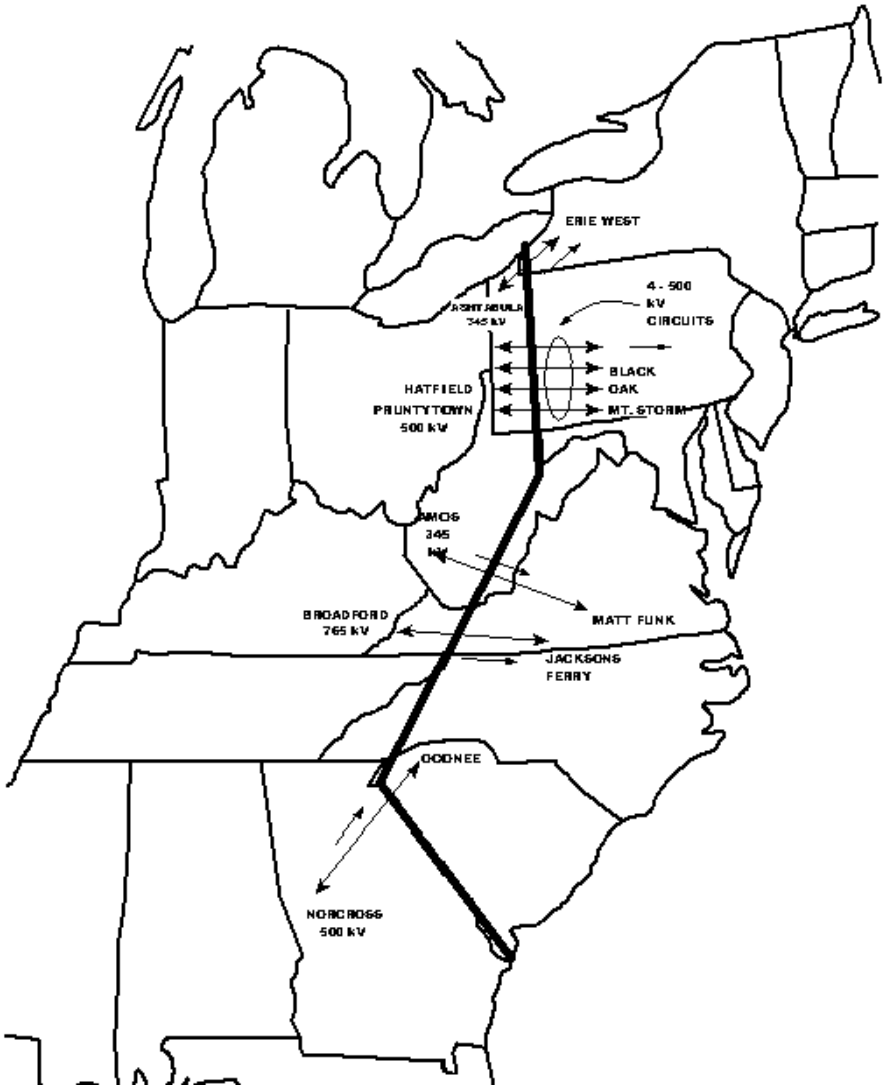


Figure 5.4.1 A "zipper" Defined by an Inter-Region Planning Coordination Group

One "zipper" is shown in Fig. 5.4.1. It was documented in a VACAR-AEP Southern-TVA Study Group report for 1984 Summer conditions [VAST-1984]; it has no formal name. Another well-known interface is that between Georgia and peninsular Florida. There are several flowgates, (as that term is used in recent transmission operations) that lie along this zipper. There are several other zippers, including one that roughly matches the eastern boundary of New York State, from the asynchronous border with Quebec to the Long Island Sound.

Another zipper runs from the Atlantic Ocean near Elizabeth City NC westerly to the WECC border in Colorado, generally following the southern borders of Virginia, Kentucky, Missouri, and Kansas. There are other zippers in the EI, not described here.

These zippers are important to system dynamics since they are, by definition, places with relatively few transmission links. If one of the lines across the zipper is tripped, each of the remaining zipper-crossing lines will pick up the flows from the tripped line in addition to that line's pre-contingency flow. Since the aggregate impedance across the zipper increased with the line trip, this flow shift is necessarily accompanied by an increase in the generator rotor angles; this stimulates the innate power system dynamic response that quite frequently is of interest.

5.5 Physical Limits to Oscillatory Modes Across Interconnections

Both the Ontario Hydro team that made the analyses for COSS [COSS -2 1994] and Graham Rogers [Rogers 1999] define the frequency range for oscillatory stability issues, and both set the lower limit of the modal frequency at 0.2 Hz. This is probably based on an observation made by Charles Concordia in the course of his consultation for the Pacific Northwest-Pacific Southwest interconnection that formed the present WECC. Charlie made the observation that the lowest limit for transmission strength, sufficient for an interconnection to be viable, is about 0.1 Hz. Charlie came to these observations in the 1960s, during his consultation for the Pacific Northwest-Pacific Southwest interconnection that formed the present WECC. I expect that he shared these observations with many, and that it is in some one or more of his many papers.

As far as I know NO UTILITY has used this physical limitation to set alarms in power system operation, based on real-time measurements of modal frequencies. Implementing this facility will not be easy.

6.0 Concluding Remarks

This white paper touches on many topics in power system dynamics, With many other peoples experiences added, this may be a very useful asset.

The conclusions in this paper are summarized in paragraphs 2.3, 2.5, 3.2.3, and sections 5.0 through 5.5.

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