Real-Time Applications of Phasor Measurement Units (PMU) for Visualization, Reactive Power Monitoring and Voltage Stability Protection

Final Report 10-33

November 2010

nyserda

Energy. Innovation. Solutions.

The New York State Energy Research and Development Authority (NYSERDA) is a public benefit corporation created in 1975 by the New York State Legislature.

NYSERDA derives its revenues from an annual assessment levied against sales by New York's electric and gas utilities, from public benefit charges paid by New York rate payers, from voluntary annual contributions by the New York Power Authority and the Long Island Power Authority, and from limited corporate funds.

NYSERDA works with businesses, schools, and municipalities to identify existing technologies and equipment to reduce their energy costs. Its responsibilities include:

- Conducting a multifaceted energy and environmental research and development program to meet New York State's diverse economic needs.

- The New York Energy $martSM program provides energy efficiency services, including those directed at the low-income sector, research and development, and environmental protection activities.

- Making energy more affordable for residential and low-income households.

- Helping industries, schools, hospitals, municipalities, not-for-profits, and the residential sector, implement energy-efficiency measures. NYSERDA research projects help the State's businesses and municipalities with their energy and environmental problems.

- Providing objective, credible, and useful energy analysis and planning to guide decisions made by major energy stakeholders in the private and public sectors.

- Since 1990, NYSERDA has developed and brought into use successful innovative, energy-efficient, and environmentally beneficial products, processes, and services.

- Managing the Western New York Nuclear Service Center at West Valley, including: overseeing the State's interests and share of costs at the West Valley Demonstration Project, a federal/State radioactive waste clean-up effort, and managing wastes and maintaining facilities at the shut-down

- State-Licensed Disposal Area.

- Coordinating the State's activities on energy emergencies and nuclear regulatory matters, and monitoring low-level radioactive waste generation and management in the State.

- Financing energy-related projects, reducing costs for ratepayers.

For more information, contact the Communications unit, NYSERDA, 17 Columbia Circle, Albany, New York 12203-6399; toll-free 1-866-NYSERDA, locally (518) 862-1090, ext. 3250; or on the web at www.nyserda.org

Real-Time Applications of Phasor Measurement Units (PMU) for Visualization, Reactive Power Monitoring and Voltage Stability Protection

Final Report

Prepared for the
New York State Energy Research and Development Authority

Albany, NY
www.nyserda.org

Mark P. Razanousky
Project Manager

Prepared by:
Electric Power Research Institute (EPRI)

Dr. Stephen Lee
Project Manager

and

Dr. Liang Min
Project Manager

NYSERDA Report 10-33

NYSERDA 10470

November 2010

ACKNOWLEDGEMENTS

The project was sponsored by the New York State Energy Research and Development Authority (NYSERDA). The Electric Power Research Institute (EPRI) is the prime contractor for the project and shared part of the project cost.

The project team is led by Mr. Michael P. Razanousky, NYSERDA project manager and Drs. Stephen Lee and Liang Min, EPRI project managers. HTC Tech and Powertech Lab Inc. are subcontractors to EPRI.

The project team acknowledges the vision and support of Mr. Mark Torpey, Director of Clean Energy Research and Market Development at NYSERDA. The authors would like to acknowledge the valuable help and support from our project advisors listed below in alphabetical order. We apologize in advance for any inadvertent omissions.

Clay Burns	National Grid
Henry Chao	NYISO
Kevin DePugh	NYSEG
Jennifer Dering	NYPA
Pat Duggan	Con Ed
Bruce Fardanesh	NYPA
Mark Graham	NYPA
Rich Hackman	NYPA
Paul Haering	CHG&E
Janos Hajagos	National Grid/LIPA
Mike Hervey	National Grid/LIPA
Steve Keller	DPS
James B. Marean	NYSEG
Dejan Sobajic	NYISO
Mike Swider	NYISO
Jade Wong	Con Ed

TABLE OF CONTENTS

LIST OF FIGURES

SECTION 1

BACKGROUND

Synchrophasors are precise grid measurement devices most often called phasor measurement units (PMU). These devices are capable of directly measuring frequency, voltage and current waveforms along with phase angle differences at high sampling rates and accuracies. They are prompting a revolution in power system operations as next generation measuring devices. With the smart grid investment grant demonstrations projects funded throughout the country, an additional 850 PMUs are going to be installed in the United States to bring the total to over 1,000 in the next three years. New York State expects about 40 new PMUs to be installed in the next three years, bringing its total to over 50 units.

This project was sponsored by the New York State Energy Research and Development Authority (NYSERDA). The project team worked with CHG&E, ConEd, DPS, LIPA, National Grid, NYISO, NYPA and NYSEG to develop the project objectives to demonstrate the following three technologies, related to PMU applications, in the New York State control area:

1. Wide Area Power System Visualization
2. Critical Voltage Areas and Required Reactive Power Reserves
3. Measurement Based Voltage Stability Monitoring

WIDE AREA POWER SYSTEM VISUALIZATION

The power system operators and regional reliability coordinators of large interconnected power system typically have very detailed information of their own power systems in their Supervisory Control and Data Acquisition (SCADA) or Energy Management (EMS) systems. Nevertheless, they may not have enough real-time information about theirs or neighboring systems particularly when large disturbances occur. It is critically important for operators and coordinators to have a wide area power system visualization tool using real-time synchrophasor measurements to improve their situation awareness. When an event occurs in an interconnected power system, such as a large generator outage, it is very beneficial for the operators or coordinators to perform the near real-time event replay in fully resolutions (e.g. up to 30 sample per second) shortly after this event occurs to visualize the operating conditions using the frequency, voltage and current magnitudes and phasor angle contours of the entire interconnected power system so they will be able to work together to take appropriate and coordinated control actions to handle this event.

Tennessee Valley Authority (TVA) has developed a large Synchrophasor Super Phasor Data Concentrator (SPDC) for the Eastern Interconnection (EI). This concentrator consolidates all PMU data in the EI together to display the wide area real-time power system information. Using this data, EPRI with technical support from the research teams at TVA and Virginia Tech, has developed a real time powers system visualization tool. The current version of this application has been deployed and integrated with the Super PDC at TVA for preliminary testing and performance evaluation.

CRITICAL VOLTAGE AREAS AND REQUIRED REACTIVE POWER RESERVES

Assessing and mitigating problems associated with voltage security remains a critical concern for many power system planners and operators. It is well understood that voltage security is driven by the balance of reactive power in a system. It is of particular interest to find out what areas in a system may suffer reactive power deficiencies under some conditions. If those areas that are prone to voltage security problems, often called Voltage Control Areas (VCA), can be identified, then the reactive power reserve requirements for them can also be established to ensure system secure operation under all conditions.

A number of attempts have been made in the past to identify those areas, including a wide range of academic research and efforts toward commercial applications. There are two main types of voltage instability:

1. Loss of voltage control instability, which is caused by exhaustion of reactive supply with consequent loss of voltage control on a particular set of reactive sources such as generators, synchronous condensers, or other reactive power compensating devices.
2. Clogging voltage instability that occurs due to I^2X series inductive reactive power usages, tap changer limits, switchable shunt capacitors limits, and shunt capacitive reactive supply reduction due to decreasing voltage.

The existing methods have had only a limited success in commercial application because they cannot produce satisfactory results for practical systems. This, in general, is because of the following difficulties:

1. The problem is highly nonlinear. To examine the effects of contingencies, the system is repeatedly stressed in some manner by increasing system load and generation. The process of stressing the system normally introduces a myriad of nonlinearities and discontinuities between the base case operating point and the ultimate instability point
2. The VCAs must be established for all expected system conditions and contingencies. Finding VCAs is a large dimensioned problem because many system conditions and contingencies need to be considered. It may not be possible to identify a small number of unique VCAs under all such conditions. The VCAs may also change in shape and size for different conditions and contingencies.

To deal with these issues, a more practical approach is needed that can clearly establish the VCAs for a given system and all possible system conditions.

MEASUREMENT BASED VOLTAGE STABILITY MONITORING

In 2006, EPRI proposed an innovative measurement-based method for voltage stability monitoring and control at a bus, which is either a load bus or the single interface bus to a load area. This method was named "Voltage Instability Load Shedding" (VILS). The calculated voltage stability margin is contingency independent, and can be expressed in terms of the real or reactive power transferred via that load or interface bus. It can help system operators monitor voltage stability and understand how much load needs to be shed in order to prevent voltage collapse at the monitored bus.

EPRI has validated this control scheme using the measured data from digital fault recorders (DFR) collected during the 2003 voltage collapse event at TVA's Philadelphia, Mississippi substation. EPRI has also collaborated with New York Power Authority to validate this method at the substation level using the PMU data collected at East Garden City (EGC) substation. The previous studies' results showed the advantages of:

1. Correctly tracking the distance from current operation condition to the voltage instability edge.
2. Providing important information regarding the amount of load to be shed.
3. Estimating the critical voltage and tracking its changes to the threshold value for voltage instability.

Based on the VILS method, EPRI has invented a new measurement-based wide-area voltage stability monitoring method using PMUs, which is able to continuously calculate real-time contingency independent voltage stability margins for an entire load center using PMU measurements taken at its boundary buses. EPRI collaborated with Entergy in 2007 to move this technology toward voltage stability assessment for load centers and examined the feasibility of applying the technology to Entergy's West Region system. An article titled "Entergy and EPRI Validate Measurement-Based Voltage Stability Monitoring Method" has been published in the January 2009 T&D Newsletter. In the article, Sujit Mandal, Senior Staff Engineer at Entergy indicated, "The results of the validation study have shown us here at Entergy that this is promising for enhancing the security of our transmission system."

SECTION 2

PROJECT OBJECTIVES AND STUDY APPROACHES

WIDE AREA POWER SYSTEM VISUALIZATION

The objective of this task is to perform the research, development and demonstration of the wide area power system visualization application using real-time synchrophasor measurements and post event analysis using historical synchrophasor measurements.

The main performance challenges of the wide area power system visualization application includes how to efficiently handle large volumes of synchrophasor measurements and how to support large numbers of concurrent users for performing real-time reliability monitoring, near real-time event replay or post event analysis. This task first describes the new technologies used in the wide area power system visualization to meet the performance requirements. The new technologies include the memory residence object oriented database, event oriented database and use of the smart client technologies.

The system architecture overview is shown in the Figure 2-1. This wide area power system visualization system includes the following modules:

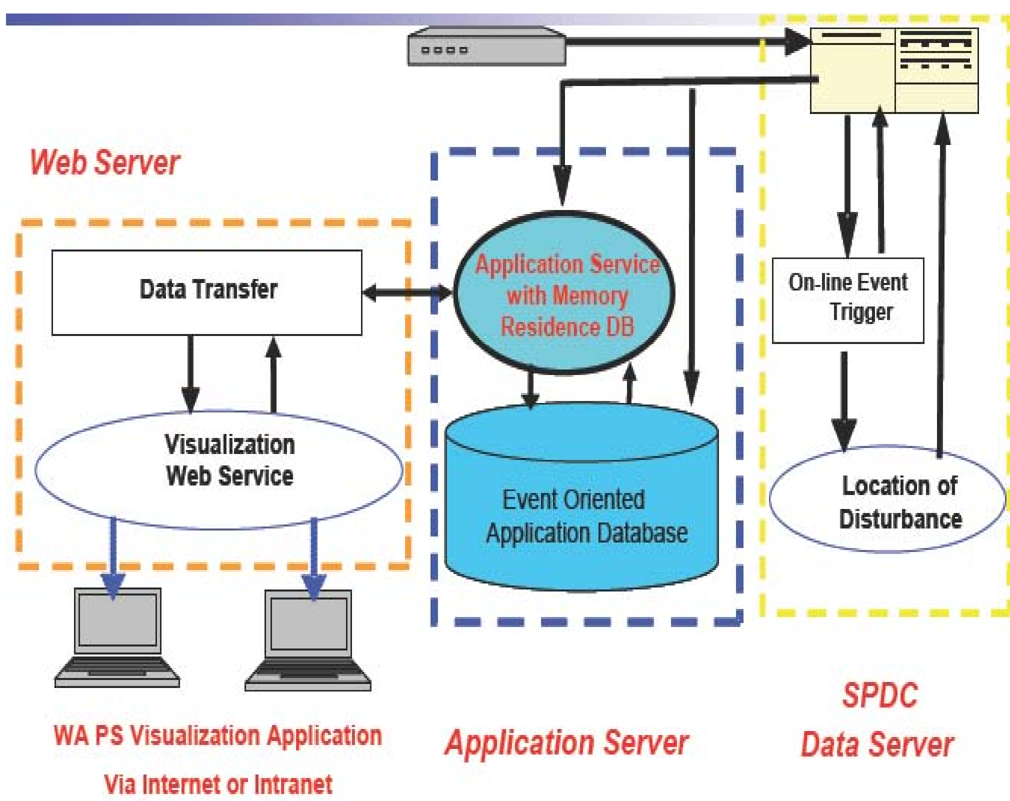


Figure 2.1. Visualization System Architecture Overview

This system includes voltage magnitude contours display, phase angle contour display, frequency contour display, angle differences and user-defined dashboards for the real-time reliability monitoring and post event replay.

The wide area power system visualization application will be extensively demonstrated using real-time or historical synchrophasor measurements of the Eastern Interconnection or simulated synchrophasor measurements.

Critical Voltage Areas and Required Reactive Power Reserves

The objectives of this task are to:

1. Identify Critical Voltage Areas in New York Transmission System
2. Determine minimum reactive power reserve to maintain voltage stability with specified margins given the reactive reserve criteria.

This project is not intended to address the issue of the proportional requirements for static vs. dynamic Vars needed in each VCA. This mix depends on the nature of the instability and the characteristics of load and system components, and can only be properly established by using time-domain simulations.

Also, the focus of this project is on developing and demonstrating an approach that is suitable for use in the off-line (i.e. system planning) environment in which many scenarios spanning a given planning horizon must be examined. In this environment the volume of analysis may be much higher than in the on-line environment, but computation time, though always important, is not a mission critical requirement as in the case of on-line analysis. The issue of on-line VCA determination will be addressed in the next phase of the project.

The tasks uses a software framework capable of analyzing large complex power systems and establishing (i) areas prone to voltage collapse (i.e, Voltage Control Areas or 'VCAs'), (ii) the margin to instability for each VCA, (iii) the contingencies, which lead to the collapse of each VCA, (iv) the generators that can control each VCA, and (v) the amount and generator allocation of reactive power reserves, which must be maintained in order to ensure voltage stability. The software framework (VCA-Offline BETA) is now ready to be demonstrated in the analysis of large practical power systems.

The task of VCA identification is a very challenging problem primarily due to the fact that voltage security problems are highly nonlinear and VCAs may also change in shape and size for different system conditions and contingencies. To deal with these issues, a more practical approach was adopted by this project to clearly establish the VCAs for a given system under all system conditions. The approach is based on a PV Curve method combined with Modal Analysis. The general approach is as follows:

1. Define a system operating space based on a wide range of system load conditions, dispatch conditions, and defined transactions (source-to-sink transfers).
2. Define a large set of contingencies that spans the range of credible contingencies.
3. Using the PV curve method, push the system through every condition, under all contingencies until the voltage instability point is found for each condition.

4. At the point of instability for each case (nose of the PV curve) perform modal analysis to determine the critical mode of instability as defined by a set of bus participation factors corresponding to the zero eigenvalue.
5. Store the results of the modal analysis in a database for analysis using data mining techniques to identify the VCAs and track them throughout the range of system changes.
6. Establish the reactive reserve requirements for each identified VCA.

MEASUREMENT BASED VOLTAGE STABILITY MONITORING

The objectives of this task are to demonstrate the new approach developed by EPRI called Voltage Instability Load Shedding, to prevent voltage collapse with an automatic safety net, or system protection scheme that will automatically shed the right amount of load to arrest an impending voltage collapse by using high-sampling rate digital measurement devices such as Digital Fault Recorders (DFR), PMUs or intelligent electronic devices (IED) installed at the substation level. Also; demonstrate its ability to provide real-time voltage stability margins that are computed from the real-time data of the DFR, PMU or IED. Such information will be provided to task for monitoring and visualization.

EPRI has invented a new measurement-based wide-area voltage stability monitoring method using PMUs, which is able to continuously calculate real-time contingency independent voltage stability margins for an interface or a load center using measurements taken at its boundary buses.

To validate the invention, it is necessary to determine critical substations associated with voltage stability problems. Past experiences with New York transmission planners on the potential interfaces associated with voltage instability problem are used to the maximum degree so as to select the most promising substations. We perform steady-state P-V analysis for voltage stability constrained interfaces to determine critical substations. A more intelligent way is developed to rely on visualization tools to display dynamic voltage performance for each scenario to identify voltage control areas that are displaying consistently lower voltages across all scenarios.

Measurement-based voltage stability monitoring methods typically contains the following steps:

- Obtain synchronized voltage and current measurements at all boundary buses using PMUs
- Determine a fictitious boundary bus representing all boundary buses, and calculate the equivalent voltage phasor, real power and reactive power at this bus
- Estimate the external system’s Thevenin equivalent parameters
- Calculate power transfer limits at the interface of the load center using the Thevenin equivalent
- Calculate voltage stability margins in terms of real power and reactive power

Since PMUs are not currently available at the determined critical substations, we will perform time-domain simulations using PSS/E to obtain the voltage and current waveforms as pseudo PMU data. We will examine the feasibility of the proposed measurement-based voltage stability monitoring method on the Central East interface of the New York system using pseudo PMU data generated by time-domain simulation.

SECTION 3

STUDY RESULTS

WIDE AREA POWER SYSTEM VISUALIZATION

A beta version of wide area power system visualization software program was integrated with the Super Phasor Data Concentrator (SPDC) at TVA for the real-time reliability monitoring and near real-time event replay using synchrophasor measurements for improving the situational awareness of power system operators and regional reliability coordinators. The smart client technology used for this visualization application significantly improves the performance by fully making use of the local computer resources, the internet and web services in order to meet the very challenging performance requirements to support large numbers of concurrent users and to provide hi-fidelity wide area power system visualization in real-time for large interconnected power systems. The performance of this application has also been significantly improved by using the memory residence object oriented database and the advanced event oriented database to efficiently handle large volumes of real-time synchrophasor measurements and event related measurements. The unique features of the near real-time event replay will allow power system operators and reliability coordinators to monitor and analyze the new system event very shortly (within a few seconds) after the event occurred, allowing them to improve the situation awareness, and to have time to prepare appropriate corrective or preventive control actions when necessary to prevent potential cascading outages.

The wide area power system visualization application has been extensively tested using the following test cases:

- The real-time synchrophasor measurements of the Eastern Interconnection from the SuperPDC at TVA.
- The simulated synchrophasor measurements of 45 PMUs in NYISO. The simulated synchrophasor measurements were generated by a stability simulation program based on a sequence of events including two initial 345 KV line outages and a large generator outage a few seconds later.
- The frequency measurements using FNET frequency data related to a generator outage event (1200 MW).
- Simulated synchrophasor measurements using 49 PMUs for benchmark performance testing.

The main features of the visualization application can mainly be divided into the following modes:

- Real-time Reliability Monitoring
- Near Real-time Event Replay
- Post Event Replay and Analysis

The wide area power system visualization has the following visualization features:

- Voltage magnitude contour display
- Phase angle contour display
- Frequency contour display
- Angle differences
- Trending charts
- Dashboards

The voltage contour display using the simulated synchrophasor measurements from 45 synchrophasor measurement units in the NYISO area is shown in Figure 3-1. The phase angle contour display using the simulated synchrophasor measurements from 45 synchrophasor measurement units in the NYISO area is shown in Figure 3-2.

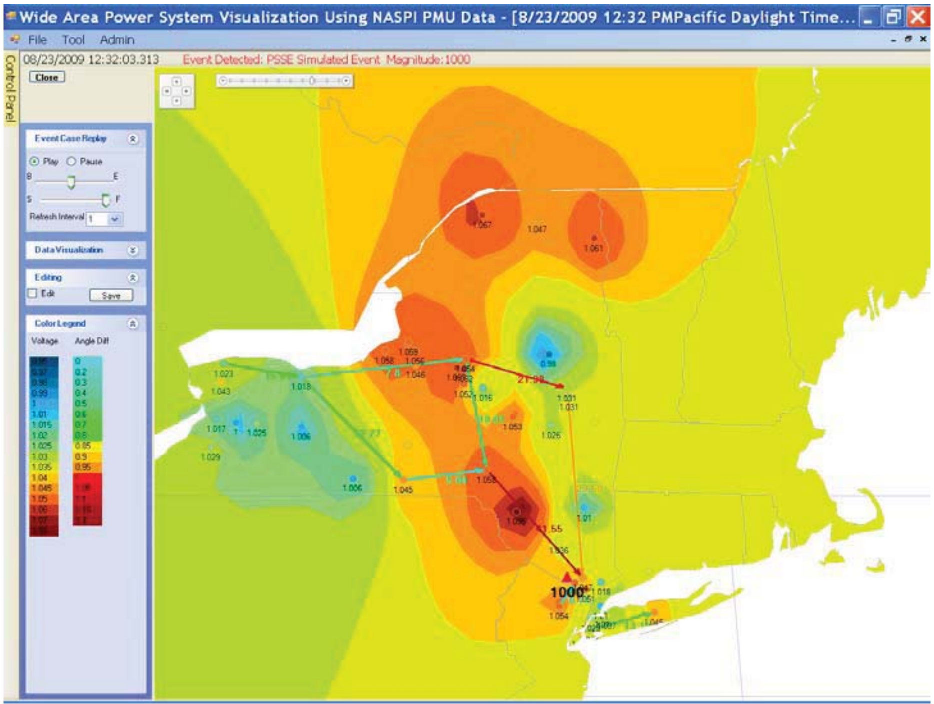


Figure 3.1. Voltage Contour Display using Simulated SynchroPhasor Measurements

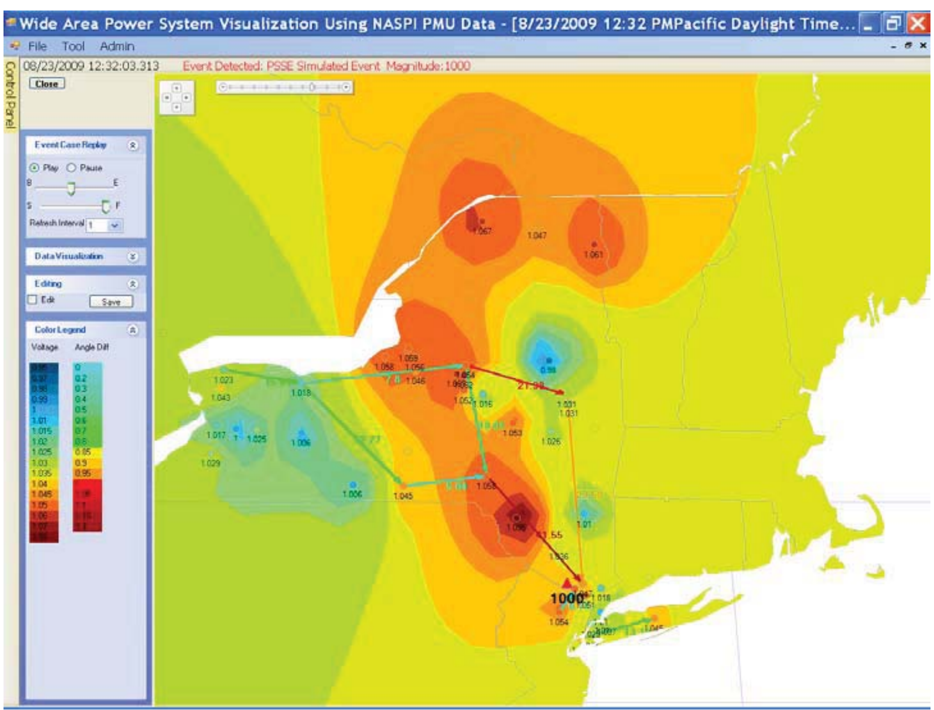


Figure 3.2. Phase Angle Display using Simulated SynchroPhasor Measurements

Critical Voltage Areas and Required Reactive Power Reserves

The NYISO voltage critical area (VCA) identification demonstration considered a set of three powerflow basecases (Summer-peaking, winter-peaking, and light load for year 2012), four cross-state transfer scenarios, and a number of pre-defined as well as N-1 contingencies. EPRI/Powertech's VCA-Offline BETA program was used in identifying the VCAs and corresponding reactive reserve requirements.

This software tool has revealed a total of four VCAs in New York, which are:[1]

- VCA#1: Located near Station EST_XX (Area 1XX0, Area 1XX5, Owner CXXD)
- VCA#2: Located near Station FRG_XX (Area 1XX0, Area 1XX5, Owner CXXD)
- VCA#3: Located near Station ERV_XX (Area 1XX0, Area 1XX5, Owner CXXD)
- VCA#4: Located near Station KNC_XX (Area 6XX, Zone 2XX1, Owner NXXG)

In Figure 3-3 highlights of the VCA # 1 is shown and further representation is given at Figure 3-4. It can be seen that a total of seven buses are associated with this mode and 272 eigenvalues reflect this area of voltage collapse.

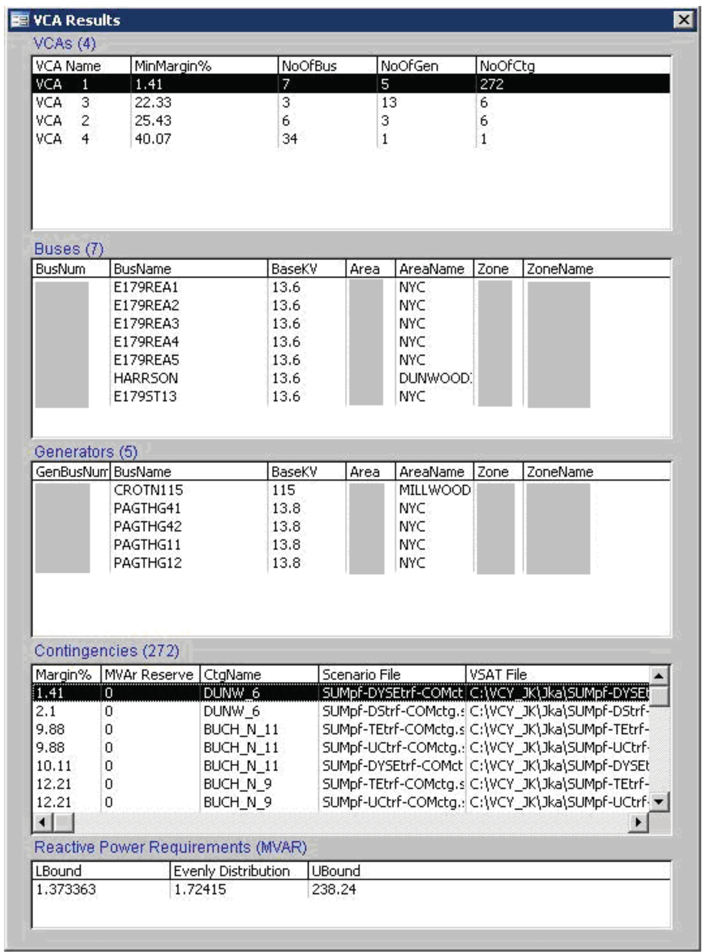


Figure 3.3. Details of VCA #1

[1] Proprietary information has been masked and further details are given in Section A-4 of Appendix B.

The total load connected through these buses is above 230 MW and 100 MVAr. Also, these buses are coupled to 138 kV bus in the East 179th Station. Voltage collapse characteristics in these buses are also shown in Figure 3-4 for contingency 'TWR 69/J&70/K'.

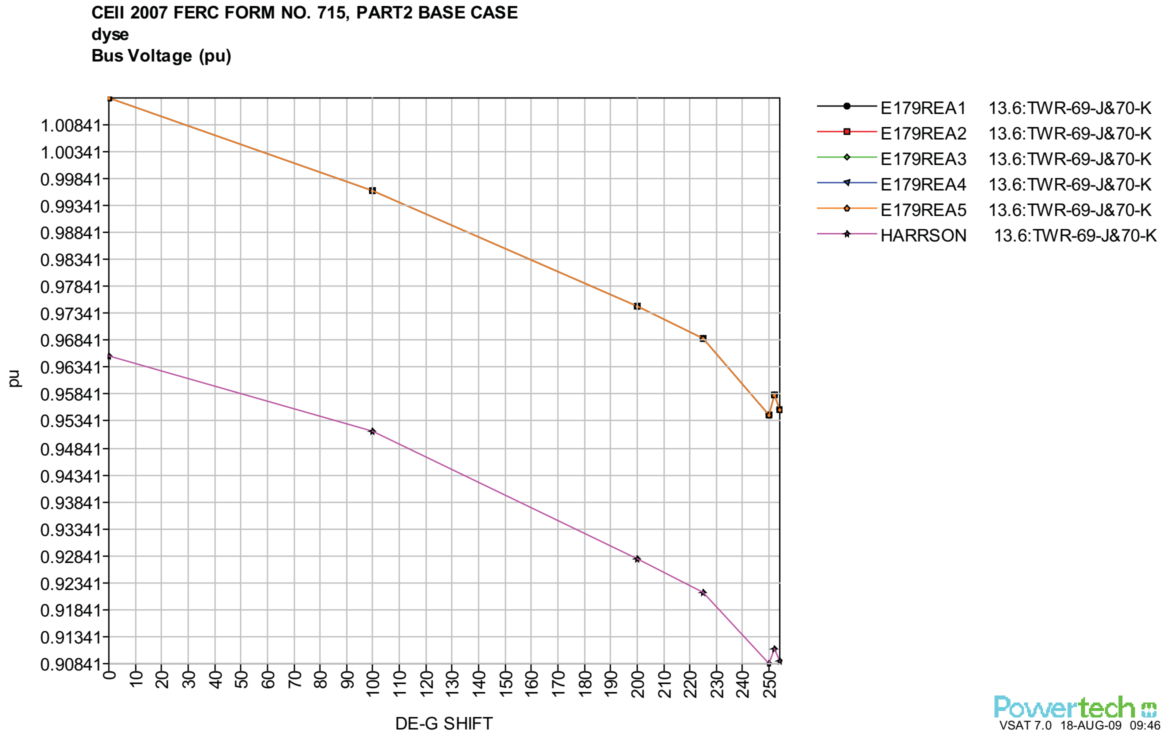


Figure 3.4. Voltage collapse profile of buses within VCA #1

The required reactive power to maintain on the generators that control voltage stability in the above weak areas (with required stability margin of 5%) varies for each area. Also, it is important to note that since VCA 2, 3, and 4 have very high margins (>22%), there is no need to specify any reactive power requirement for them.

The required reactive power of the controlling generators in the weak area-1 (VCA #1) is approximately 230 MVAR. It is also important to consider how many contingencies are supporting a specific VCA when the reactive power requirement is being sought. An example is the VCA #4. In this VCA there are 34 buses with one controlling generator. This VCA is only supported by one contingency.

Pursuant discussions have revealed that:

- Considering the geographical proximity and network configurations, VCA#1, #2, and #3 can apparently be treated as a single VCA.
- Considering the fact that VCA#4 is reflective of a local load distribution issue, this VCA can be ignored.

It has also been observed that the current VCA-Offline BETA program needs to be advanced such that elements of utility owner/operator’s experience can be incorporated into the program intelligence.

Measurement Based Voltage Stability Monitoring

This task demonstrated a synchrophasors based voltage stability monitoring methodology for load centers. The method has a means for measuring current and voltage phasors at boundary buses of a load center and an equivalent network having a fictitious bus with an aggregate load representative of imported power to that load center. The method further includes a computing algorithm to calculate voltage stability margins indexes based on the aggregate load of the fictitious bus and comparing voltage stability margins indexes with a pre-set thresholds. The computing algorithm also causes an action to take place based on the comparison between these margins and thresholds. The proposed method has been validated on the Central East Interface of NYISO. Since phasor measurement units are not installed at receiving end substations of the Central East Interface, we performed a time-domain simulation to obtain voltage and current phasors at those substations and use them as pseudo synchrophasor data for validation purpose.

The results show that the Measurement-base Voltage Stability Monitoring method:

- Detected voltage instability problems in real-time
- Aided operators by monitoring system voltage stability conditions and providing the power transfer limits in terms of real or reactive power.

This monitoring function does not require modeling transmission system components and does not rely on the SCADA/EMS. The margin information provides system operators not only the power transfer limit to a load center (or on the transmission corridor), in terms of active power, but also the reactive power support needed. This information can be used as decision support for operator to take actions to improve voltage stability. The set of control actions included but was not limited to:

- Increasing reactive power output from generators
- Switching on shunt capacitors
- Increasing reactive power output from SVC
- Configuration of transmission network
- Load shedding

Analytical studies have demonstrated the advantages and benefits of using this technology to monitor voltage instability on the Central East interface. With all this knowledge in hand, we are collaborating with NYISO and Transmission Owners to move this invention into the pilot studies and then into full-scale demonstration.

New York State now has 10 PMUs installed at NYPA, ConEd, and LIPA territories. All of the PMU data is being sent to TVA’s Super PDC through a secure fiber network. NYISO is focusing on expanding the number of PMUs, developing a Phasor Data Collector (PDC) and deploy real-time wide area monitoring capabilities on grid dynamics to operators and reliability coordinators. It is necessary to develop an interface between the Measurement Based Voltage Stability Monitoring (MB-VSM) program and NYISO’s PDC so that the MB-VSM program can use New York State’s existing and future PMU data.

A number of tests need to be performed in order to verify the performance and examine the robustness of the MB-VSM algorithm. We need to validate the correctness of the computation results and check the computation time of the MB-VSM program using the historical PMU data, as well as assess the robustness of the MB-VSM program against the potential loss of a PMU, and some communication channels. The following existing PMUs were used to examine the performance of MB-VSM:

UPNY-ConEd interface:

- FARRAGUT -345KV (existing PMU)
- SPRBROOK – 345KV (existing PMU)

LIPA Import interface :

- E.G.C.-1 – 345KV (existing PMU)

The full-scale demonstration phase requires PMUs to be installed at designated locations to monitor voltage stability on the Central-East and UPNY-ConEd (or Millwood South) interfaces. The following table shows the proposed implementation architecture of the MB-VSM on the New York System.

Bus Name	KV	TO	MBVSM TE/CE	MBVSM UC/MS
BUCH N	345	ConEd		
DUNWODIE	345	ConEd		X
FARRAGUT	345	ConEd	X	X
GOTHLS N	345	ConEd	X	X
RAMAPO	345	ConEd	X	
SPRBROOK	345	ConEd		X
E.G.C.-1	345	LIPA	X	X
NWBRG	345	LIPA	X	X
COOPC345	345	NYSEG	X	
N.SCOT77	345	Ngrid	X	
ROTRDM.2	230	Ngrid	X	
GILB 345	345	NYPA	X	
N.SCOT99	345	Ngrid	X	

These PMUs will measure the voltage magnitude and angle of the key substation buses, as well as the current of the key transmission lines, which are required by the MS-VSM program. Communication equipment and the necessary communication network connection needs to be established in order to transfer the synchrophasor data from the PMUs to the NYISO's PDC. The MB-VSM program will be installed at the application server connecting with NYISO's PDC and will use the synchrophasor data provided by NYISO's PDC to calculate the voltage stability margin of the Central-East and UPNY-ConEd (or Millwood South) interfaces on a continuous basis. The voltage stability margin will be displayed on a designated computer screen at NYISO's control center for system operators to monitor the voltage stability condition of these two interfaces. Once the voltage stability margin falls below a user-specified threshold, an alarm message will be generated to inform system operators.

SECTION 4

CONCLUSION

This project successfully demonstrated the wide area power system visualization software program using real-time synchrophasor measurements and simulated synchrophasor data. The software was deployed at TVA and was integrated with the Super Phasor Data Concentrator using real-time synchrophasor measurements of about 120 PMUs for the whole eastern interconnection. The project identified four Critical Voltage Areas in New York System and determined minimum reactive power reserve to maintain voltage stability within specified margins given the reactive reserve criteria. A more intelligent way described in Appendix C was to use visualization tools to display dynamic voltage performance for each scenario to identify voltage control areas that consistently displaying lower voltages across all scenarios. By combining the results of the Critical Voltage Areas and visualization tools, the central east interface was determined to demonstrate the measurement based voltage stability monitoring methodology. The results show that the measurement based voltage stability monitoring method can detect voltage instability problems in real-time and aid operators by monitoring system voltage stability conditions and providing the power transfer limits in terms of real or reactive power.

EPRI, NYISO, and NYSERDA jointly held a public workshop on May 25th 2010 along with two-days training on May 26th and 27th 2010. More than 50 attendees from electric utilities operators and planners, researchers, software developers, vendors, and non-governmental organizations attended the public workshop. The purpose of reaching out to this broad audience was to inform the public, to promote research in the synchrophasor application, and to provide useful technical information for potential commercialization of methodologies developed in this research project. Representatives from all New York utilities and NYISO were involved in the software program training on May 26th and 27th. The tools developed through this project are being using by NYISO and New York utilities.

This pilot project has demonstrated the advantages and benefits of using these technologies to improve system operator's situational awareness. With all this knowledge in hand, we are collaborating with NYISO and NY utilities to move these technologies into full-scale demonstration.

New York expects about 40 new PMUs to be installed in the next three years, bringing the New York state total to over 50. New York State may have its own PDCs, or Super PDC, at the NYISO in the future. Communication equipment and the necessary communication network connection will be established in order to transfer the synchrophasor data from the PMUs to the NYISO's PDC. The wide area power system visualization software program will be installed at the web server/s at the NYISO or utilities that have their own PDCs. The measurement based voltage stability monitoring software program will be installed at the application server connecting with NYISO's Super PDC and will use the synchrophasor data provided by NYISO's PDC to calculate the voltage stability margins for specific interfaces.

APPENDIX A

WIDE AREA POWER SYSTEM VISUALIZATION, NEAR REAL-TIME EVENT REPLAY AND LOCATION OF DISTURBANCE

NYSERDA AGREEMENT WITH ELECTRIC POWER RESEARCH INSTITUTE (EPRI) NO. 10470

FINAL TASK REPORT

Prepared for:

New York State Energy Research and Development Authority
Albany, NY

Project Manager
Michael P. Razanousky

Prepared by:
Electric Power Research Institute (EPRI)
3420 Hillview Avenue, Palo Alto, CA 94304

Project Managers
Dr. Stephen Lee and Dr. Liang Min

Task Manager
Dr. Guorui Zhang

SEPTEMBER, 2010

Acknowledgements

This research, development and demonstration project was sponsored by the New York State Energy Research and Development Authority (NYSERDA).

This research, development and demonstration project was also sponsored by ConEd and TVA.

We thank Mr. Mark Torpey and Mr. Michael P. Razanousky of NYSERDA and Ms. Jade Wong of ConEd for sponsoring this research and development project. We gratefully acknowledge the contributions of our contractor of this project, HTC Tech, for the research, development and implementation of the wide area power system visualization application using real-time or historical synchrophasor measurements. We also thank the contributions, suggestions and technical support of the advisors of this NYSERDA R&D project, the technical team of NYSIO, NYPA, ConEd, LIPA and National Grid. We thank the TVA technical team including Mr. Ritchie Carroll, Ms. Lisa Beard and Dr. Jian Zuo for their effort of development of the SuperPDC and the support of the integration of the EPRI wide area power system visualization application at TVA. We also thank the contribution of the technical team of Prof. Yilu Liu at Virginia Tech for the enhancements and integration testing of the location of disturbance (LOD) application using synchronous frequency measurements. We also thank Dr. Liang Min of EPRI for preparing the simulated PMU data for the integration testing.

Table of Contents

List of Figures

Executive Summary

It is critically important for improving the situation awareness of the operators or the operational planning engineers in a power system control center of Regional Transmission Operator (RTO), Independent System Operator (ISO) or an Electric utility and in regional reliability coordinators of large interconnected systems to prevent large scale cascading system outages. This report describes the results of the research, development and demonstration project funded by NYSERDA. The R&D and demonstration project has developed and demonstrated an advanced wide area power system visualization application for power system operators, operational engineers and regional reliability coordinators to perform the real-time reliability monitoring using real-time synchrophasor measurements and to perform the post event analysis using historical synchrophasor measurements related to large system events. This report also describes a very useful feature that potentially will allow a large number of users to perform the near real-time event replay a few seconds after a new large system event occurs in a large interconnected power system so that the operators will have enough time to prepare the appropriate corrective or preventive control actions if necessary. The wide area power system visualization application can also show the location, magnitude and the related event message on the visualization display in real-time by integration with the on-line event detection and location of disturbance applications. The location, magnitude and the related event message shown on the display immediately after the event occurs will allow the users to know what is happening in the interconnected power system and to take appropriate control actions if necessary.

The main performance challenges of the wide area power system visualization application include how to efficiently handle large volume of synchrophasor measurements and how to support large number of concurrent users for performing real-time reliability monitoring, near real-time event replay or post event analysis. This report describes the new technologies used in the wide area power system visualization to meet the performance requirements. The new technologies include the memory residence object oriented database, event oriented database and utilization of the Smart Client technologies. The system architecture, the technical approaches and the solution algorithms used in this wide area power system visualization are described in detail in this report. The wide area power system visualization using synchrophasor measurements includes voltage magnitude contours display, phase angle contour display, frequency contour display, angle differences and user-defined dashboards for the real-time reliability monitoring and post event replay.

The wide area power system visualization application developed in the research, development and demonstration project for reliability monitoring, near real-time event replay and post event analysis has been extensively tested using real-time or historical synchrophasor measurements of the Eastern Interconnection, or simulated synchrophasor measurements. A beta version of this wide area power system visualization application was integrated with the Super Phasor Data Concentrator (SPDC) at TVA for the real-time reliability monitoring and near real-time event replay using the real-time synchrophasor measurements for improving the situation awareness of power system operators and regional reliability coordinators. The initial results of the performance testing are encouraging and will be presented and discussed in this report. The Smart Client technology used for this power system visualization application significantly improves the performance by fully making use of the local computer resources, the Internet and the Web Services in order to meet the very challenging performance requirements to support large number of concurrent users and to provide hi-fidelity wide area power system visualization in real-time for large interconnected power systems. The performance of this application has also been significantly improved by using the memory residence object oriented database and the advanced event oriented database to efficiently handle a large volume of real-time synchrophasor measurements; the event related measurements. The unique features of the near real-time event replay allow power system operators and reliability coordinators to monitor and analyze the new system event very shortly (a few seconds) after the event occurred, allowing them to improve the situation awareness and to have time to prepare appropriate corrective or preventive control actions when necessary to prevent potential cascading outages. The voltage contour display using the simulated synchrophasor measurements from 45 synchrophasor measurement units in the NYISO area is shown in Figure 1. The phase angle contour display using the simulated synchrophasor measurements from 45 synchrophasor measurement units in the NYISO area is shown in Figure 2.

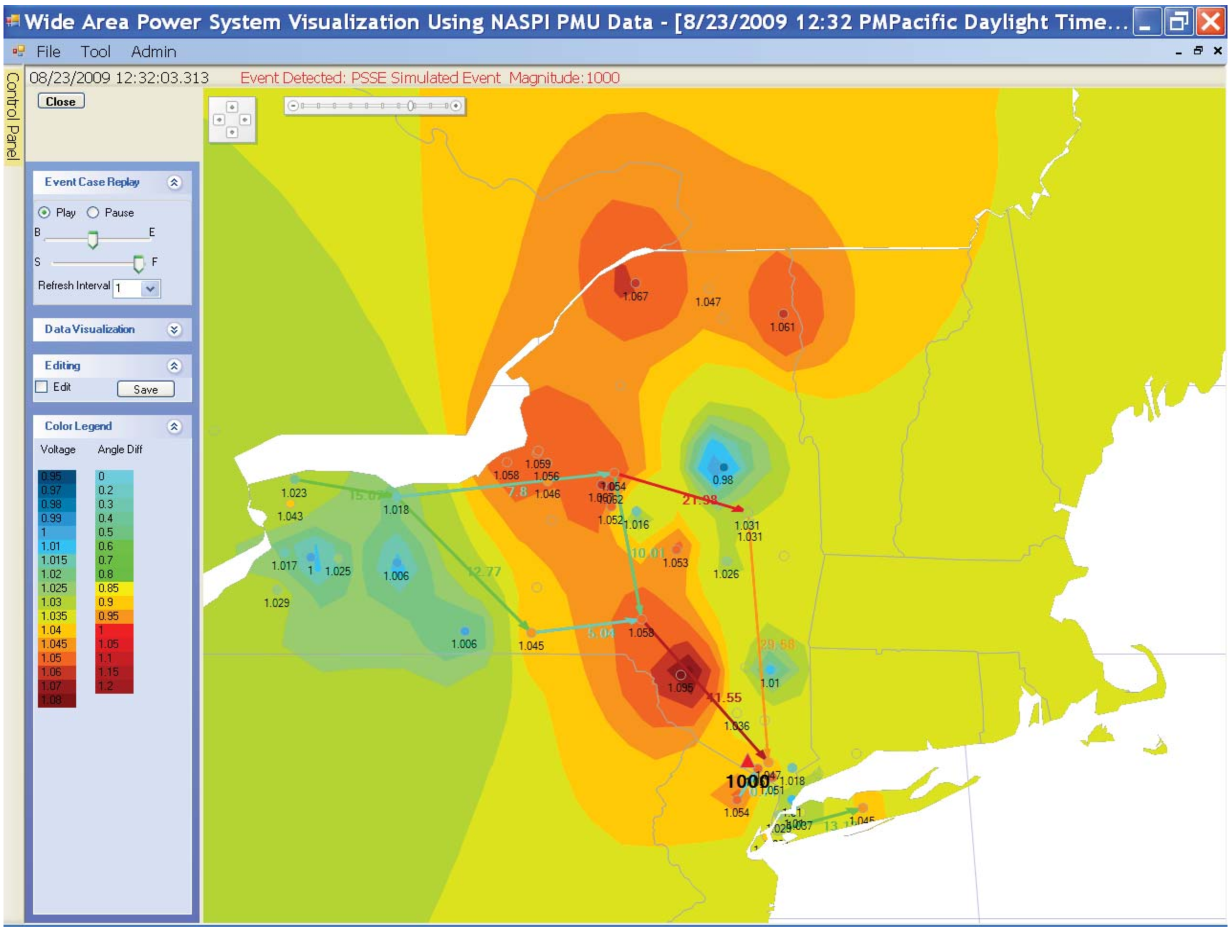


Figure 1 Voltage Contour Display using Simulated SynchroPhasor Measurements

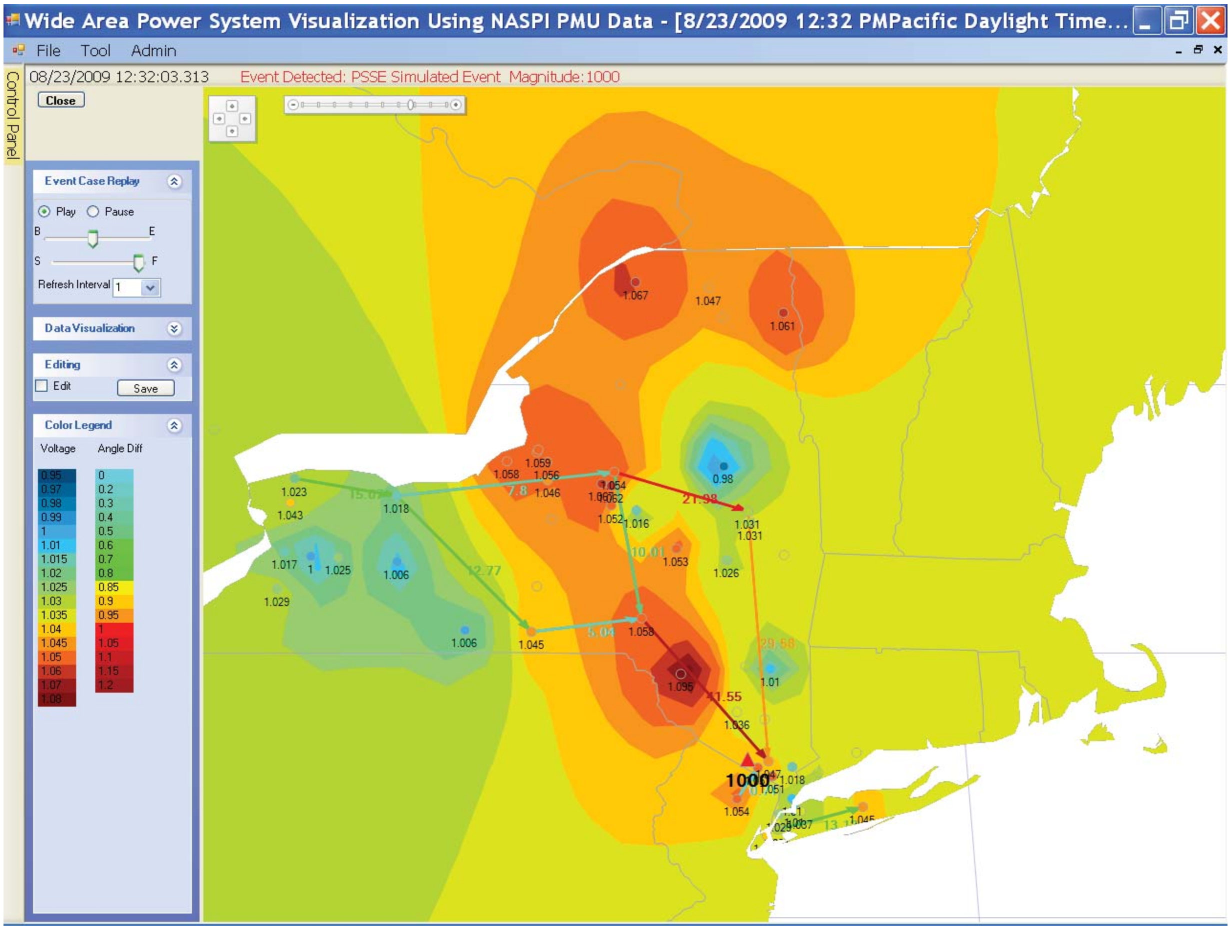


Figure 2 Phase angle Contour Display using Simulated SynchroPhasor Measurements

Background

The operators and regional or regional reliability coordinators of a large interconnected power system typically have very detailed information of their own power systems in their SCADA / EMS systems. Still, they may not have enough real-time information about their neighboring systems, particularly when large disturbances occur in their neighboring systems. It is critically important for power system operators and regional reliability coordinators to have a wide area power system visualization tool using real-time synchrophasor measurements to improve their situation awareness [1]. When a large event occurs in an interconnected power system, such as a large generator outage, it will be very beneficial for the operators or reliability coordinators to perform the near real-time event replay in fully resolutions (e.g. up to 30 sample per second) shortly after a large event occurs to visualize the operating conditions using the frequency, voltage magnitude and phasor angle contours of the entire interconnected power system such that the operators and reliability coordinators of the power systems affected by the large event occurred will be able to work together to take appropriate and coordinated control actions to handle the large events.

A large number of synchrophasor Measurement Units (PMU) have been installed in the United States. With the new R&D and demonstration projects funded by the US DOE Smart Grid Investment program, it is expected that more than 850 new PMUs will be installed in the Eastern Interconnection (EI), Western System Coordination Council and ERCOT in Texas power systems [2]. The increasing number of synchrophasor measurement units to be installed in the American electric utilities will provide more opportunities for the wide area real-time power system reliability monitoring and controls using the synchrophasor measurements.

In the last few years, a lot of research and development effort has been spent to develop applications to use the Synchrophasor measurements (frequency, voltage magnitude and phase angle) for the real-time reliability monitoring, state estimation, stability control and post event analysis of interconnected power systems [3,4,5,7]. EPRI, TVA and Virginia Tech have been working together to develop a wide area power system visualization using real-time and historical synchrophasor measurements for the real-time reliability monitoring and post event analysis. TVA has developed a synchrophasor Phasor Data Concentrator (SPDC) for the Eastern Interconnection. The wide area real-time power system visualization using the real-time synchrophasor measurements has been developed by EPRI with the technical support from the research teams at TVA and Virginia Tech. The current version of the wide area real-time power system visualization application has been deployed and integrated with the *Super Phasor Data Concentrator (SPDC)* at TVA for preliminary testing and performance evaluation. The initial testing results are very encouraging.

The system architecture, the detailed implementation and the test results of the wide area power system visualization and near real-time event replay are presented in this report.

Project Objectives

The objective of the Task 2 of this research, development and demonstration project is to perform the research, development and demonstration of the wide area power system visualization using real-time synchrophasor measurements and post event analysis using historical synchrophasor measurements.

Smart Client Technology

Smart clients are easily deployed, and managed client applications provide an adaptive, responsive and rich interactive experience by fully using local computing resources and intelligently connecting to distributed data sources. Unlike browser based application, smart client applications are installed on a user's PC, laptop, or other smart devices. Smart client applications, when connected to the Internet or Intranet can exchange data with systems across the Internet or the enterprise. Web services, which are widely used in smart client applications, allow the smart client application to use industry standard protocols, such as XML, HTTP and SOAP, on any type of remote system. Smart client can work whether connected to the Internet or not. Smart client applications can be easily deployed from a centralized web server and can also automatically update to the latest version of the software installed on the centralized server.

System Architecture Overview

The system architecture overview of the wide area power system visualization system using synchrophasor measurements is shown in Figure 1. This wide area power system visualization system includes the following modules:

Synchrophasor Measurement Data Server

The synchrophasor measurement data server collects and processes the synchrophasor measurements from phasor data concentrators (PDC). The data conditioning will be performed to detect and replace any missing or wrong synchrophasor measurements.

The on-line event trigger application is used for detecting any new large system disturbance such as a large generator tripping, HVDC link outage, or large load outages, by checking the frequency changes in real-time. When a new large event is detected, the location of disturbance (LOD) application will be run to identify the location, the time, the magnitude in MW, the type of the new disturbance using the real-time synchronized frequency measurements. The information of the estimated system disturbance (event) will be stored in the SPDC database and will be displayed at on the visualization display of each user's computer.

Application Server

The application server includes an application service with memory residence object oriented database, visualization application and an event oriented relational application database using Microsoft SQL 2005 Server or SQL Server 2008.

In the real-time reliability monitoring mode, the real-time synchrophasor measurements required for the visualization application such as frequencies, voltage magnitudes and phase angles are periodically transferred, with reduced resolution (e.g. one sample per second), from the SPDC data server to the application server using the application interface via .NET remoting. In order to meet the performance requirements, the synchrophasor measurements not used for the visualization application are not transferred to the visualization application server. Whenever a large event, such as a large generator tripping, is detected, the synchrophasor measurements are transferred in full resolution (e.g. 30 samples per second) from the SPDC data server to the application server in binary form on segment basis such that the users will be able to perform the near real-time event replay and analysis as soon as possible. The synchrophasor measurements are stored in the event oriented database for near real-time event replay or post event analysis.

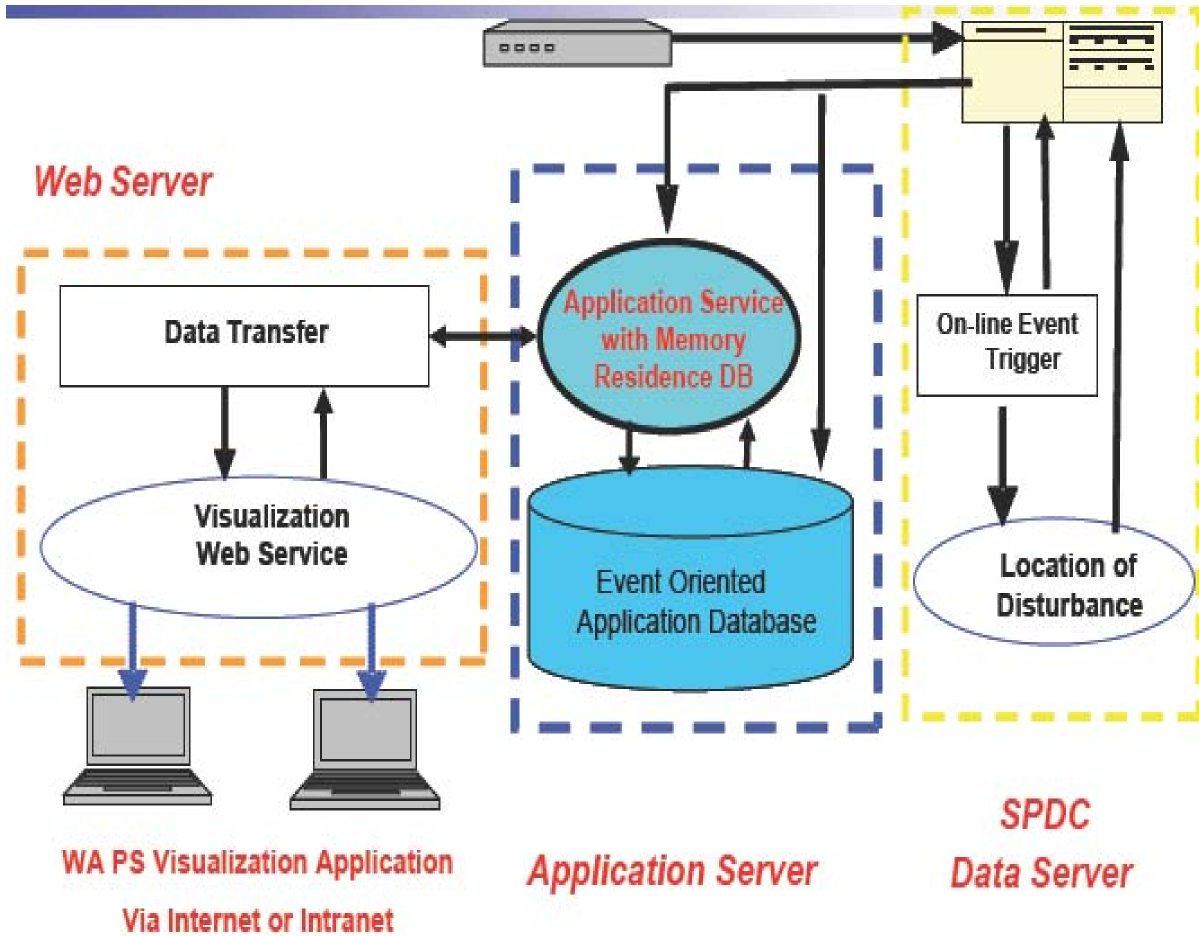


Figure 3 Visualization System Architecture Overview

Web Server

The web server performs the following functions:

- Transfer the real-time or historical synchrophasor measurements periodically (every one or two seconds) to the smart client of each user computer for real-time reliability monitoring;
- Transfer brief messages of the current event, if any, for real time event monitoring;
- Transfer the synchrophasor measurements related to the current event or a historical event on request to the smart client of each user computer for near real-time event replay of post event analysis;
- Perform the user authentication such that only the registered users will be able to log in and use the visualization application.

Implementation

The wide area power system visualization application, using real-time or historical synchrophasor measurements, is developed using Smart Client technology, the Microsoft .NET and object-oriented programming language Visual C#. This application has been successfully deployed at TVA and integrated with the Super Phasor Data Concentrator (SPDC) at TVA. The wide area power system visualization application described in this report provides the following functions:

- Real-time reliability monitoring using real-time synchrophasor measurements
- Near real-time event replay very shortly (a few seconds) after a new large system event (e.g. generator outages, load outages or major HVDC link outage) occurred
- On-line event detection using real-time synchronous frequency measurements. The new event messages including the time, location, magnitude in MW and the type of the event will be shown on the reliability monitoring displays
- Post event replay and analysis

The power system visualization displays with zooming and panning capability include the following main features:

- Voltage contour displays with angle differences
- Phase angle contour displays with angle differences
- Frequency contour displays
- Trending charts
- Dashboards (Users can specify their own dashboards for reliability monitoring.)

The main components of the power system visualization application and the special features developed for improving the system performance are described in the following sections:

Visualization Requirements

The basic requirements of the wide area power system visualization include the following:

- Efficiently transfer large volume of synchrophasor measurements from Super Phasor Data Concentrator (SPDC) to the application data server
- Efficiently transfer large volume of synchrophasor measurements from the application data server to each user's computer
- Perform near time event replay for a large number of users
- Support post event analysis performed by a large number of users who may perform event analysis for different events
- Update the contour displays for visualization 30 samples per second for each user to perform post event analysis

Memory Resident Object Oriented Database

The wide area power system visualization uses a memory resident object oriented database with a synchronized data object queue at the application server for efficiently handling the large volume of real-time and historical synchrophasor data in order to meet the performance requirements for real-time reliability monitoring, event replay and to support a large number of concurrent users. In the real-time monitoring mode, the synchrophasor measurements required for the visualization are transferred from the data server (SPDC) to the application server with reduced resolution (e.g. one sample per second) since it is normally sufficient to refresh the real-time visualization displays every second when there is no large system event. When a large event is detected, the event related synchrophasor measurements will be transferred from the SPDC data server to the application server with full resolution, i.e., 30 samples per second for the near real-time event replay.

Event Oriented Application Database

The event oriented application database at the application server is a relational database developed using Microsoft SQL Server 2005. This application database contains the following types of data:

- Phasor Measurement Unit (PMU) data including name, type, location, owner and the related information
- Event data including event name, time, location, magnitude in MW, event type and a brief message
- Event related synchrophasor measurements used for visualization application including voltage magnitude, phase angle and frequency
- Angle difference data
- Dashboard data
- Configuration parameters
- Color code data used for setting the contour colors of the visualization displays

Fast Voltage Contour Algorithms

The voltage contour algorithm is presented for voltage contours for power system visualization [2]. Similarly, a power system can also be visualized as two-dimensional frequency, voltage and phase angle visualization displays. In the near real-time event replay mode or post event replay mode, it is critically required for quickly calculating the voltage magnitude contour, phase angle contour and the frequency contour and refresh the visualization contour displays up to 30 times per second. The fast frequency contour algorithm described in [8] has been extended for the calculations of the voltage magnitude contour and phase angle contour using the synchrophasor measurements. A voltage magnitude display can be divided into M by N grids. A grid with a voltage measurement is called a measurement grid and is assigned with the measured voltage. A grid without a frequency measurement is called virtual grid and its virtual frequency needs to be calculated. In the calculation of the virtual frequency of a virtual grid, the frequency measurement units that are closer to the virtual grid should be weighted more than those that are farther away. It is very critical to implement a fast frequency contour algorithm particularly for the real-time frequency replay and for event frequency replay functions since the frequency of each grid of the display needs to be calculated for each time frame (e.g. 30 frames per second).

$$Vp = (\sum_{i \in A} (1/(Dpi * Dpi)Vi) / (\sum_{k \in A} (1/(Dpk * Dpk))) \qquad (1)$$

Where

Vp = Voltage magnitude for grid p
Vi = Voltage magnitude for grid i
Dpi = Distance from grid p to grid i
A = Subset of grids within a specified distance from grid p and is in the same power system region

The weighting factor Wpi for Vi for grid p depends on grid locations and can be pre-calculated at the initialization as follow:

$$Wpi = (1/(Dpi * Dpi))/(\sum_{k \in A}(1/(Dpk * Dpk))) \quad (2)$$

Therefore, the voltage at grid p for each time frame can quickly be calculated as follow:

$$Vp = \sum_{i \in A}(Wpi * Vi)) \quad (3)$$

The subset of grids within the specified distance used in (1) for voltage magnitude contour calculations are typically different from the corresponding subset of grids used for the frequency contour calculation or phasor angle calculations.

Real-Time Power System Visualization

A synchrophasor measurement of a Phasor Measurement Unit (PMU) typically has 30 samples per second. Some PMU measurements may have up to 60 samples per second. It is not necessary to transfer the real-time synchrophasor measurements in full resolution (e.g. typically 30 to 60 samples per second) and to refresh the real-time visualization displays for real-time reliability monitoring in the normal power system operating conditions in order to reduce the data communication requirements and to improve the responsiveness of power system visualization for each user. Therefore, for the real time power system reliability monitoring, it is sufficient to transfer and show one example of synchrophasor measurements per second.

Near Real-Time Event Replay

It typically takes several weeks or even several months to reproduce the sequence of events of a large power system disturbance. With a large number of phasor measurement units installed in an interconnected power system, it will be possible to perform the post event analysis using the synchrophasor measurements. It will be critically important for power system operators and reliability coordinators to perform near real-time event replay with full resolution (30 samples per second) when a large disturbance occurs to improve the operator situation awareness. The near real-time event replay using the synchrophasor measurements related to a recent will help the power system operators, managers and engineers to quickly understand and analyze the current events, and take appropriate corrective or preventive control actions if possible. The main challenge for the near real-time event replay is the efficient handling of large volume of event related synchrophasor measurements and to support a large number of users who may concurrently play the latest system event. The approach described in this report significantly improves the performance of the near real-time event replay by using the following technologies:

- Efficiently handle the large volume of event-related synchrophasor measurements required for the visualization application. When a large system disturbance occurs, the synchrophasor measurements (frequency, voltage magnitude, phase angle) are stored in the relational application database in binary format and on segment basis.

- Transfer the event-related synchrophasor measurements from the application server to the smart client on each user's computer on segment basis such that the visualization displays can be updated without waiting for the complete set of event data. This implementation will have the same performance whether the sequence of events is one minute or 30 minutes, or even longer.
- Use the memory resident object oriented database
- Perform near time event replay locally, fully using the computer resources using Smart Client
- Use efficient contour calculation algorithm for visualization displays
- Allow user to set the refreshing rate of the visualization displays for event replay. For example, it may be sufficient for the near real-time event replay to refresh the visualization displays 50 to 60 times per second.

Visualization for Post Event Analysis

All the large events and the corresponding synchrophasor measurements are stored in the event database. In the post event analysis mode, each user will be able to select one of the previous events available in the event oriented database to perform the post event analysis with full resolution (e.g. visualization contour displays are updated up to 30 samples per second depending on the visualization option selected by the user). The synchrophasor measurements of the selected event are transferred from the application database to the smart client at the user's computer in binary form on segment basis and processed for visualization application so that the user can start the event replay as soon as the first segments of event related data are available. The user can speed up or slow down the event replay speed and show the trending charts of the selected synchrophasor measurements during the post replay analysis. The user can also create new dashboards or update the existing dashboards, using drag and drop operation for reliability monitoring for the selected synchrophasor measurements.

On Line Event Detection

The frequency of a power system will significantly change when a large generator tripping occurred or a large load rejection occurs in a power system due to the imbalance of system generation and load. Therefore, the system frequency changes and the rates of such frequency changes can be used as an indicator for a large system disturbance. When the changes of the frequency measurements of several PMUs exceed a specified threshold value within a specified time interval (e.g. one second), a system event is detected. As soon as an event is detected, an event message including the event time, and a brief message, is inserted into the event oriented database. The location of disturbance function will be triggered to run to determine the location, event type, and the magnitude of the newly detected system event.

Location of Disturbance

The location of disturbance (LOD) was developed by Virginia Tech using synchronous frequency measurements of FNET units or other synchrophasor frequency measurements based on the event triangulation algorithms suitable for on-line applications [3]. The LOD application will be triggered to run when a new large disturbance is detected. The output of the LOD application will be the time when the event occurred, the estimated location, the magnitude in terms of MW and the type (e.g. generator outage, load outage or transmission line outage) of the event.

Configuration of SynchroPhasor Measurements

The XML based configuration file of the synchrophasor measurements of the Eastern Interconnection is prepared for the population of the application database and for the configuration of the application interface to transfer the synchrophasor measurements from the database server to the application data server.

Common Reference Phase Angle

The Performance Requirements Task Team (PRTT) of the Eastern Interconnection Phasor Project (EIPP) developed a document for defining a system-wide phase angle reference for real-time visualization applications [10]. The virtual common reference phase angle calculation was implemented at TVA to calculate as the average angle of the phase angles of three PMUs installed at Cordova, Volunteer and Lowndes substations as shown in Figure XXX. The average phase angle is not associated with any real buses but rather a “virtual bus”, which is defined as virtual Browns Ferry bus [10]. The main advantage of using the angle of the virtual bus is the improved availability and reliability of the common reference phase angle. Each synchrophasor angle measurement will be subtracted by the common reference phase angle for each time frame for the wide area power system visualization application.

Each user of the wide area power system visualization application may specify his or her own common reference bus, if necessary, by selecting the phase angle measurement of a Phasor Measurement Unit as the common reference angle.

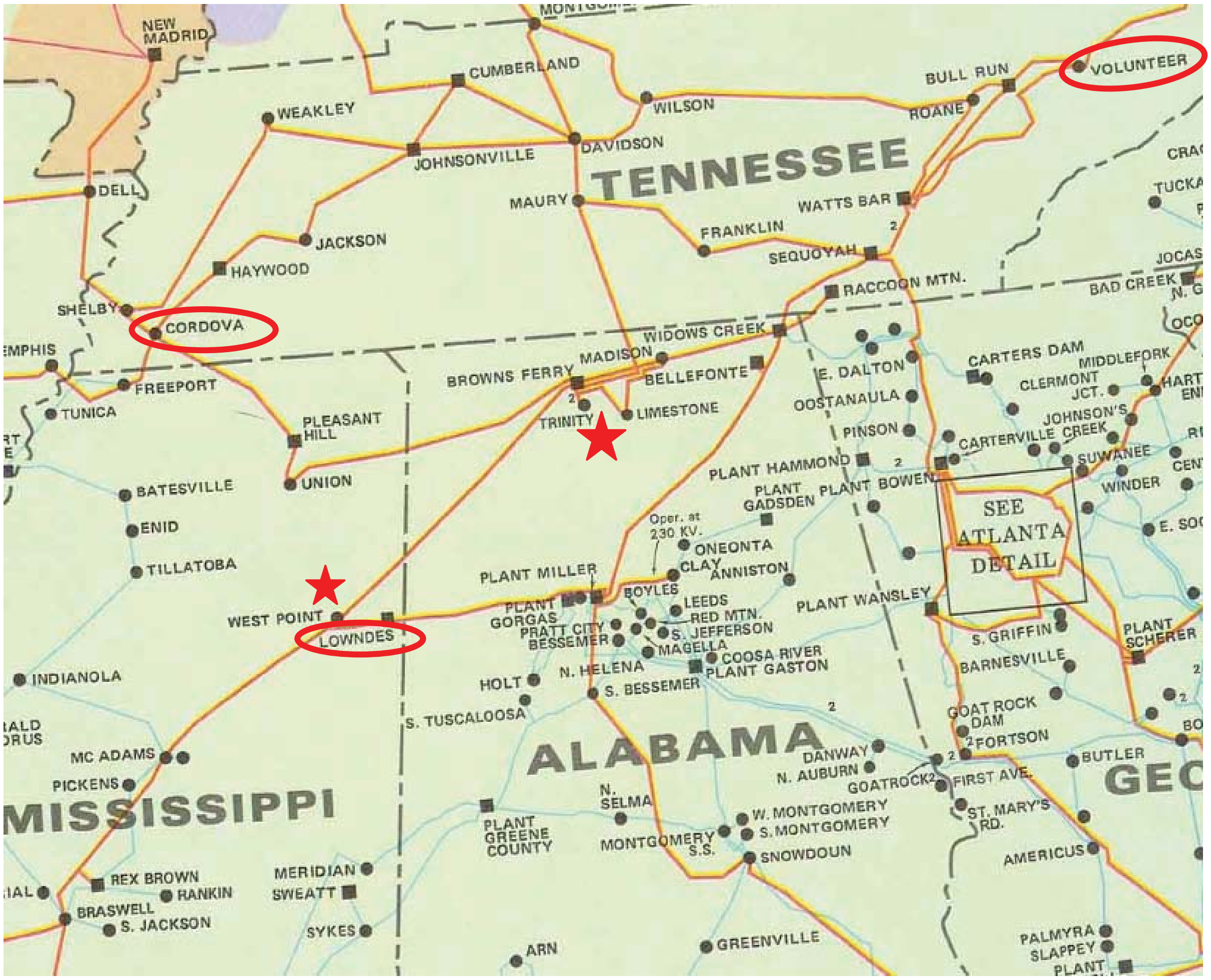


Figure 4 Map of Browns Ferry/Trinity/Limestone and nearby substations (Source: NERC map)

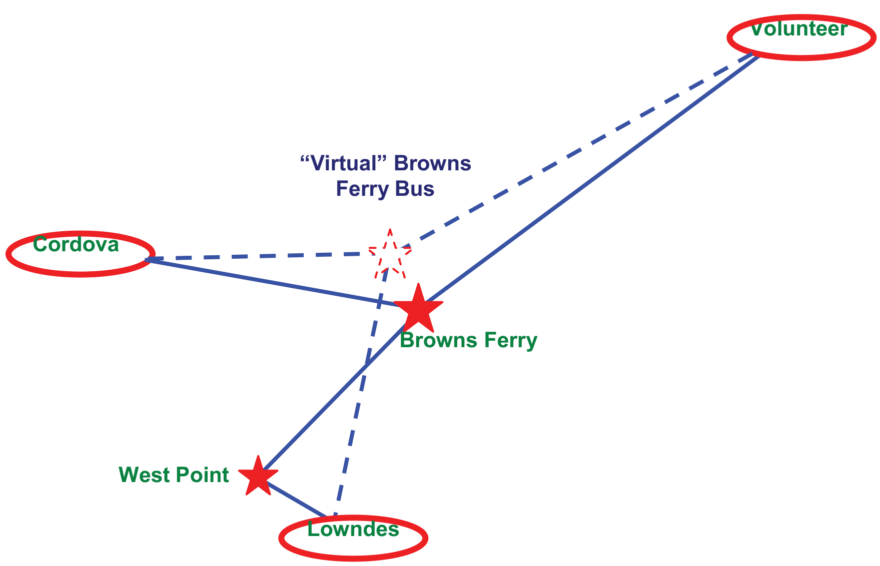


Figure 5 "Virtual" Browns Ferry bus (Source of Reference [10])

Data Conditioning

In a real-time environment, a synchrophasor measurement may be lost or become a bad measurement due to the malfunction of a PMU, lost of the communication link or a measurement channel. Each synchrophasor measurement typically has a quality flag to indicate its quality of the measurement in a Phasor Data Concentrator (PDC). Each PMU typically has also a status flag to indicate its status (e.g. on-line or off-line or malfunction) in a PDC. A data conditioning function of the application interface at the SPDC is developed to pre-process all synchrophasor measurements before transferring the synchrophasor measurements from the SeperPDC to the visualization application server. The synchrophasor data conditioning function has the following features:

- Preprocess the synchrophasor data to detect any missing data or bad data
- Replace the missing or bad synchrophasor data by the corresponding latest synchrophasor data
- Convert each voltage magnitude measurement from Volt to P.U. values
- Calculate each phasor angle measurement considering the common reference phasor angle for each time frame

Application Interfaces

The application interfaces for the visualization application perform the following functionalities:

- Perform data conditioning to handle missing and bad measurements
- Transfer the real-time synchrophasor measurements required for visualization from the SPDC data server to the application servers for real-time reliability monitoring with reduced resolution (e.g. one sample per second)
- Insert the synchrophasor measurements related to a new event with full resolution (e.g. 30 samples per second) into the event oriented database

The real-time synchrophasor measurements are transferred from the SPDC data server to the visualization application server every one second.

The implementation for the real-time reliability monitoring is designed to greatly improve the performance by storing a specified time period (say 250 to 500 seconds) of the latest real-time PMU data in the memory residence object oriented database in order eliminating the unnecessary and time-consuming database operations (inserting and reading) for the real-time measurements. The real-time PMU data is transferred every one second directly from the memory residence database to the smart client on each user’s computer for the real-time reliability monitoring. When a new event is detected by the on-line event detection module, the synchrophasor measurements (e.g. 10 seconds before the event time and 300 seconds after the event time) and the event data are inserted into the event oriented database in binary format on segment basis for the near real-time or post event replay and analysis The efficient handling of the large volume of event data together with other technologies described in this report allow us to perform the near real-time event replay a few seconds after the event occurs.

Graphical User Interface (GUI)

Control Panel

For the real-time monitoring mode, the control panel provides the following functionalities:

- Data Visualization
- Editing
- Color Legends

For the event replay mode, the control panel provides the following functionalities:

- Event Case Replay
- Data Visualization
- Editing
- Color Legends

Dashboards

The dashboards provide reliability monitoring overview using the trending charts of the following types of synchrophasor measurements selected by the users:

- Frequencies
- Voltage magnitudes
- Phase angles
- Angle differences

Figure 4 shows an example of the dashboards.

Figure 6 Figure 7 Example of Dashboard Display

Test Results

The wide area power system visualization application has been extensively tested using the following test cases:

- The real-time synchrophasor measurements of the Eastern Interconnection from the SuperPDC at TVA
- The simulated synchrophasor measurements of 45 PMUs. The simulated synchrophasor measurements were generated by a stability simulation program based on a sequence of events including two initial 345 KV line outages and a large generator outage a few seconds later.
- The frequency measurements using FNET frequency data related to a generator outage event (1200 MW)
- Simulated synchrophasor measurements using 49 PMUs for benchmark performance testing

The main features of the visualization application can be mainly divided into the following modes:

- Real-time Reliability Monitoring
- Near Real-time Event Replay
- Post Event Replay and Analysis

The wide area power system visualization has the following visualization features:

- Voltage magnitude contour display
- Phase angle contour display
- Frequency contour display
- Angle differences
- Trending charts
- Dashboards

In the near real-time event replay and post event replay modes, the user can speed up or slow down the replay speed or adjust the visualization display to refreshing rate . The user can also use the zooming and panning features to examine the visualization displays in more details for the selected areas.

Performance Benchmarking

The extensive performance benchmark tests were performed using different test cases. One of the test cases used a small laptop (IBM T60 laptop with 2 GB memory) and the simulated synchrophasor measurements of 49 PMUs with 300 seconds of event data. The performance testing results are shown in Table 1. In the traditional approach, the PMU measurements are inserted into the event oriented database one by one. For the new approach described in this report, the PMU measurements related to an event area inserted into the database in binary form and on segment basis (20 seconds of PMU data for each segment for this testing). It took 33 seconds to insert the PMU event data using the approach described in this report compared with 644 seconds using the traditional approach. It took only one second to read the complete set of PMU event data using the approach described in this report compared with 25 seconds using the traditional approach. The initial visualization display showed up in about five seconds after the event occurred, using the new approach, while it took about 858 seconds to show the initial display after complete transferring the complete event data using the traditional approach. The performance testing results are shown in Table 1 using simulated data of 49 PMUs with 300 seconds event data using a laptop.

Table 1: Performance Testing Results

	Traditional Approach (Second)	New Approach (Second)
Insert event data into Database from PMU data server	644	33
Read event data from event database from application server	25	1
Visualization display shows up after an event is detected.	858	About 5

Tests Using SynchroPhasor Measurements of 45 Simulated PMUs

This test was performed using the synchrophasor measurements of the simulated PMUs, which were created using a stability simulation program for a sequence of events. The sequence of events used for the simulation testing is described as follows:

1) At 08/23/2009 **15:32:00 (EDT) ,** faults occurred at Marcy T1 345 kV and Fraser 345 kV buses
2) After four cycles clear the faults by tripping the 345 kV line from Marcy T1 to Coopers Corner and the 345 kV line from Fraser to Coopers Corner
3) At 08/23/2009 **15:32:05 (EDT)**, another fault occurred at IND PT2 22KV bus
4) After four cycles cleared the fault by dropping the generator unit #2 (**1078 MW**) at the IND PT2 and disconnecting the IND PT2 22KV bus

For the simulated sequence of events, two 345 kV transmission line outages followed by a large generator outage of 1078 MW. The simulated limits of the angle difference links were adjusted such that some of them were shown in red color due to limit violations. The screenshots of the voltage contour displays before and after the outages are shown in Figure 8 and Figure 9 respectively. The screenshots of the phase angle contour displays before and after the outages are shown in Figure 10 and Figure 11 respectively. The original common reference bus was one of the buses in the TVA area. For the testing of the visualization application, all the phasor angles obtained from the stability simulation output were adjusted in order to fit to specified color code for the visualization displays. The screenshot of the frequency contour displays is shown in Figure 12.

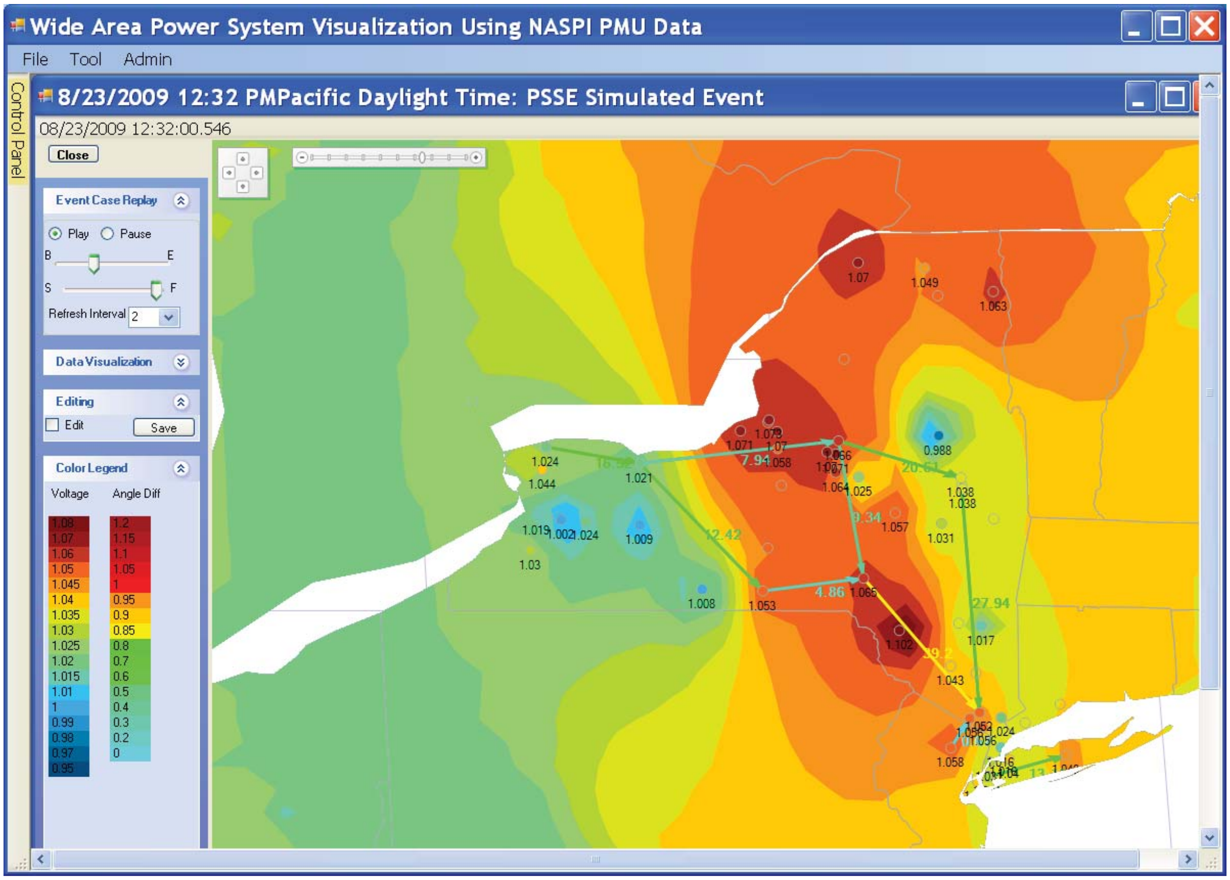


Figure 8 Voltage Contour Display using Simulated PMU Data before Outages

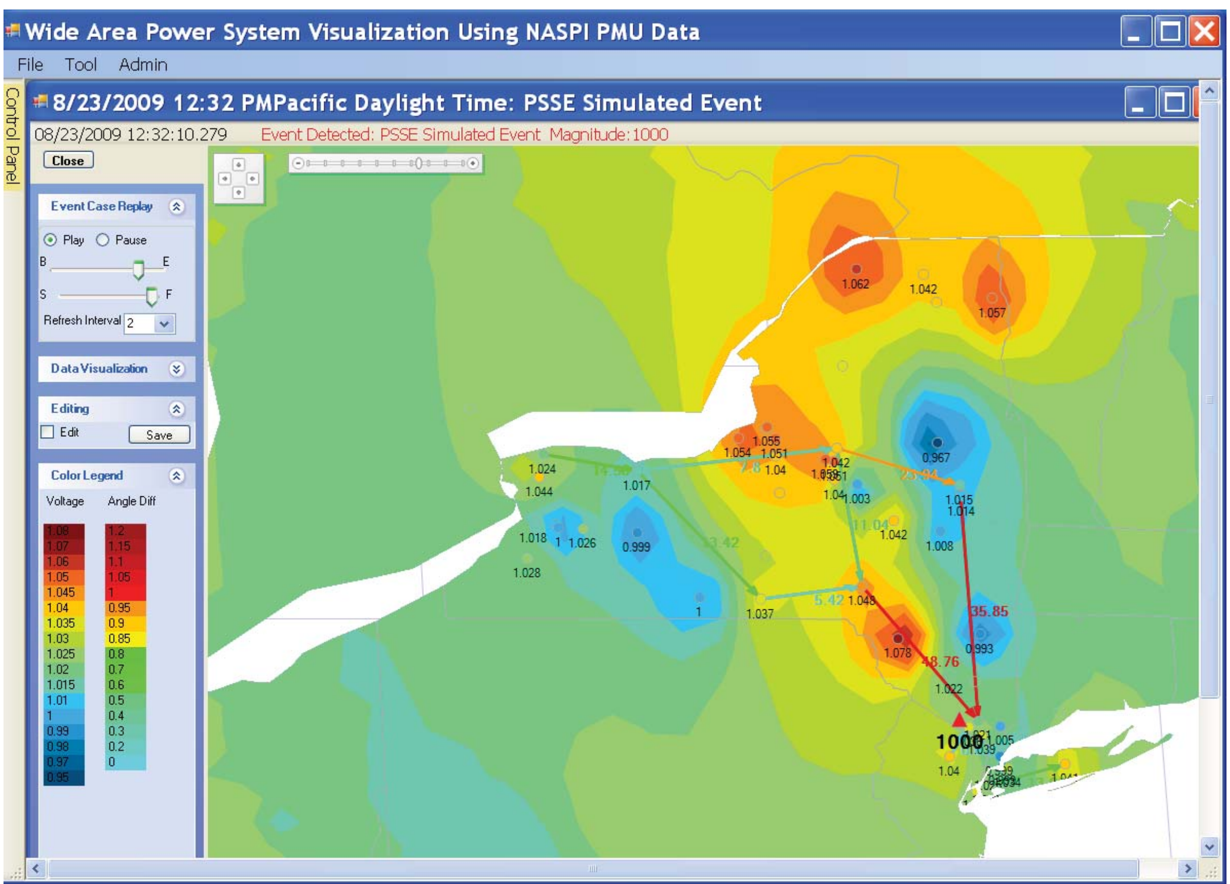


Figure 9 Voltage Contour Display using Simulated PMU Data after the Outages

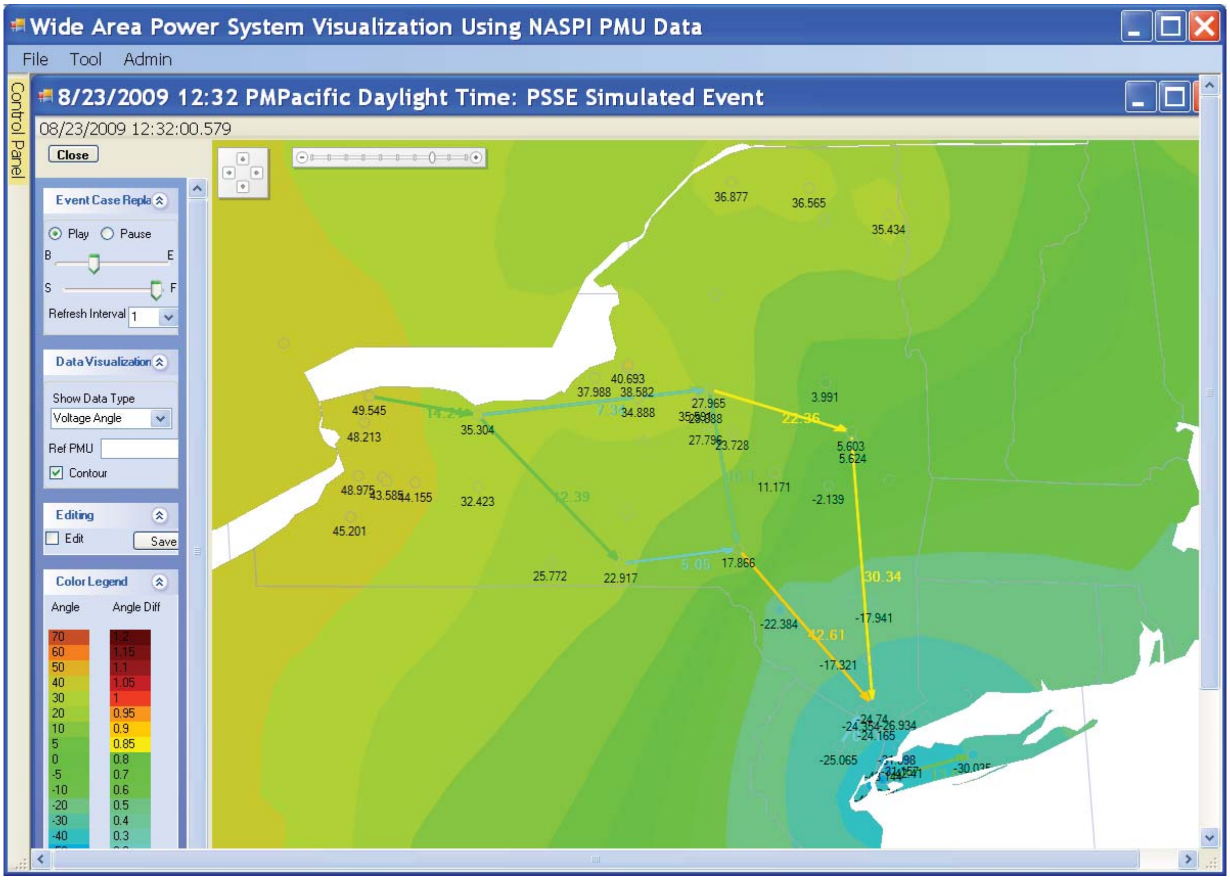


Figure 10 Phase Angle Contour Display using Simulated PMU Data before Outages

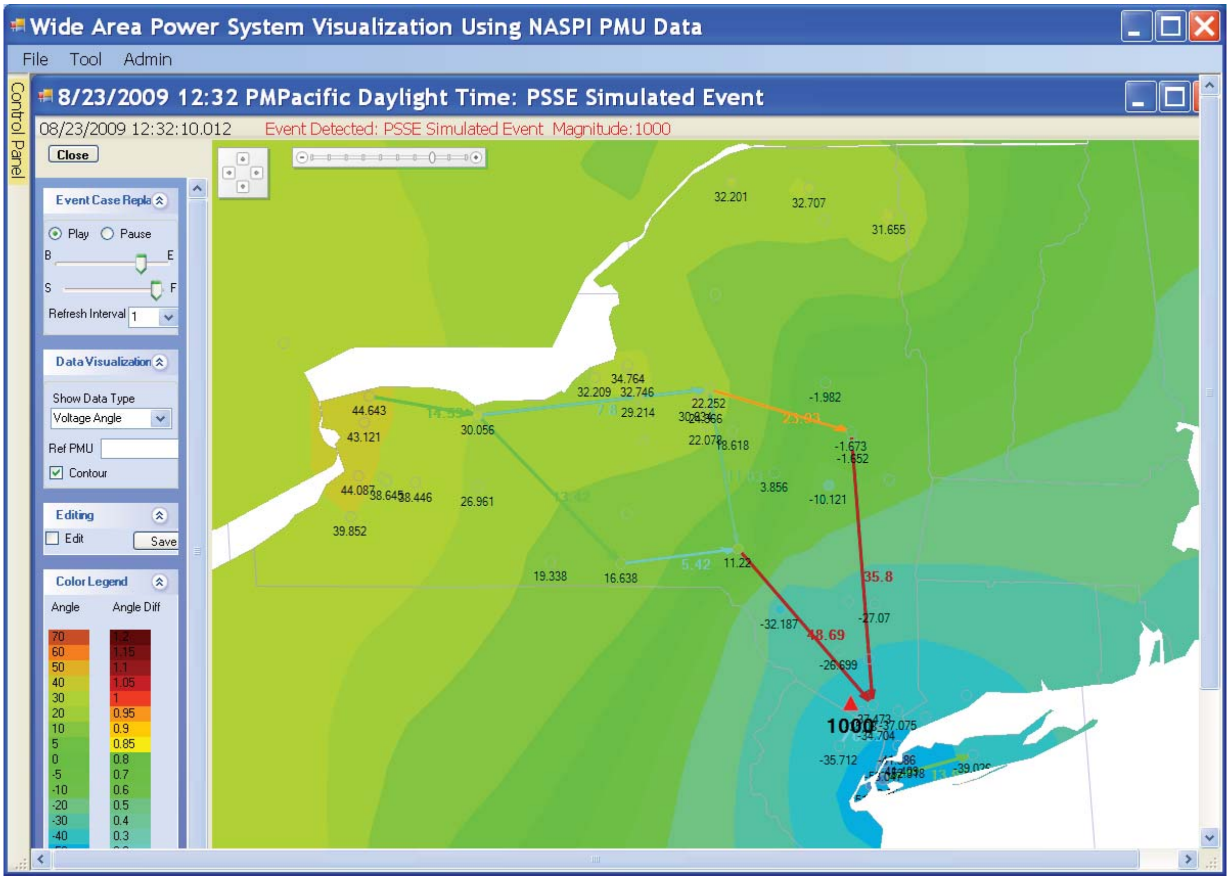


Figure 11 Phase Angle Contour Display using Simulated PMU Data after Outages

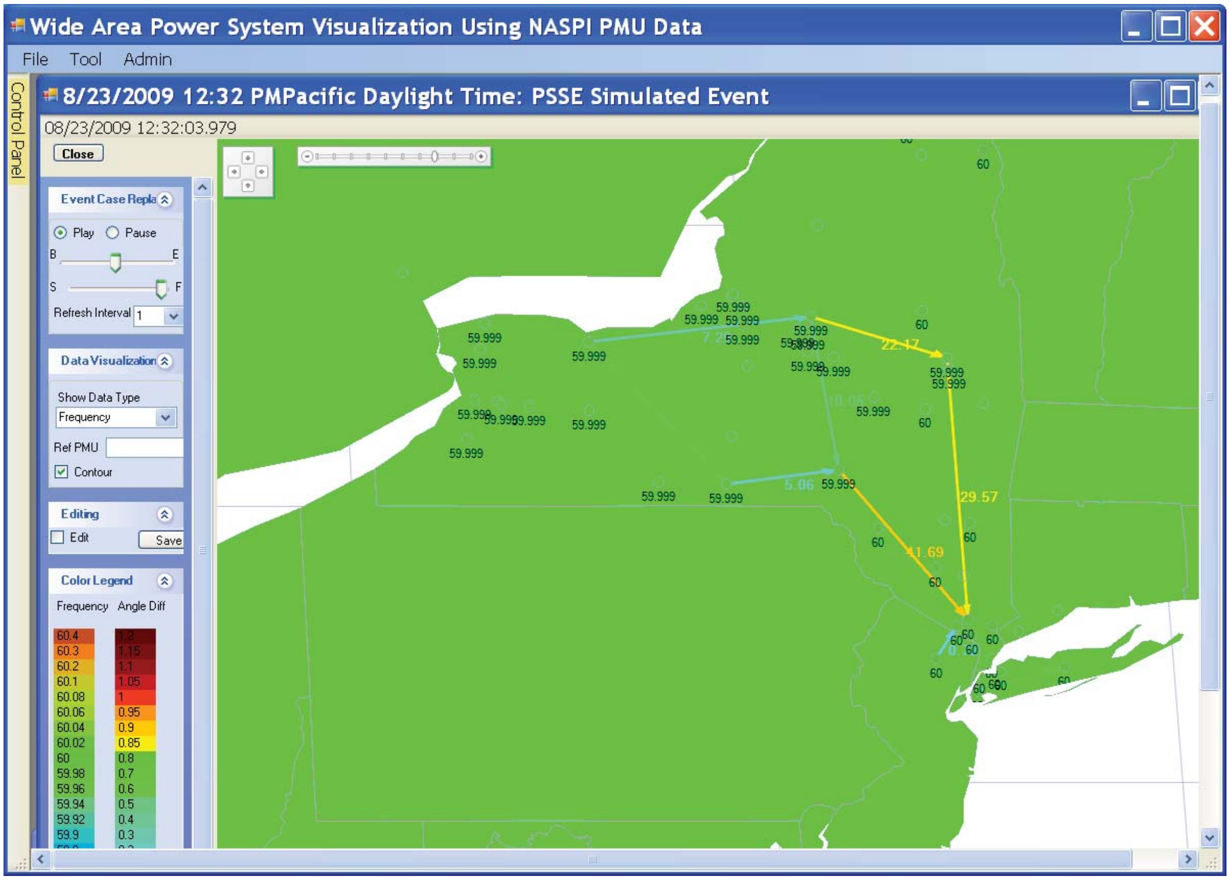


Figure 12 Frequency Contour Display using Simulated SynchroPhasor Measurements

User Selection of Common Angle reference

The user can select a phase angle of a PMU as common reference for the visualization displays. The procedure for changing the phase angle common reference is described as follows:

1) Use the mouse pointer to select a PMU on the phase angle display
2) Click the right button of the mouse to show the pull-down menu for the selected PMU
3) Select option of "Set As Phase Angle Reference"
4) The name of the selected PMU is shown in the Data Visualization section of the Control Panel
5) The angle visualization display will be updated based on the newly selected common angle reference

Figure 13 is the screenshot of the Phase angle visualization display with the angle of PMU Marcy T1 selected as the common angle reference. Figure 14 is the screenshot of the Phase angle visualization display with the angle of PMU Fraser 345 selected as the common angle reference.

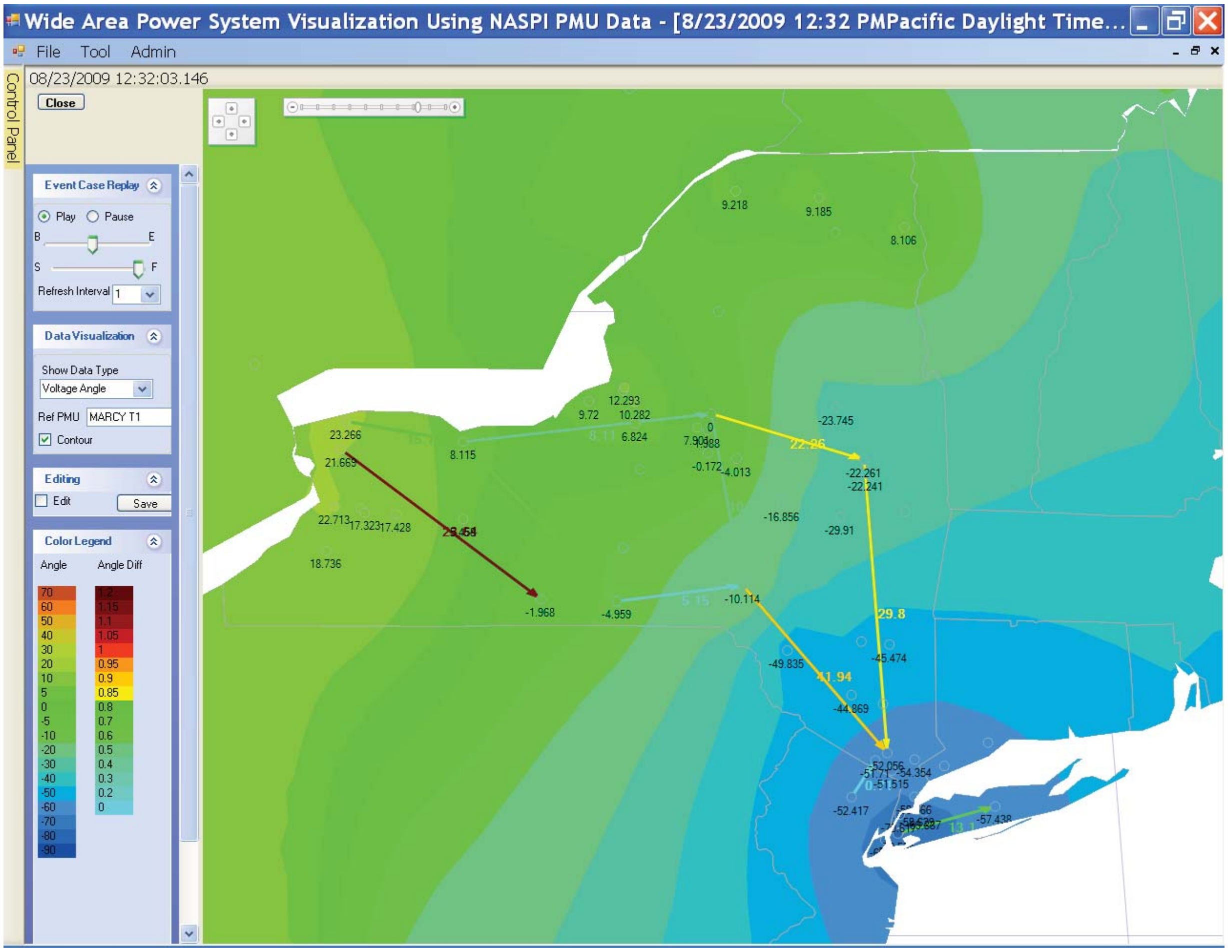


Figure 13 Phase angle display with angle of PMU at Marci T1 selected as common reference

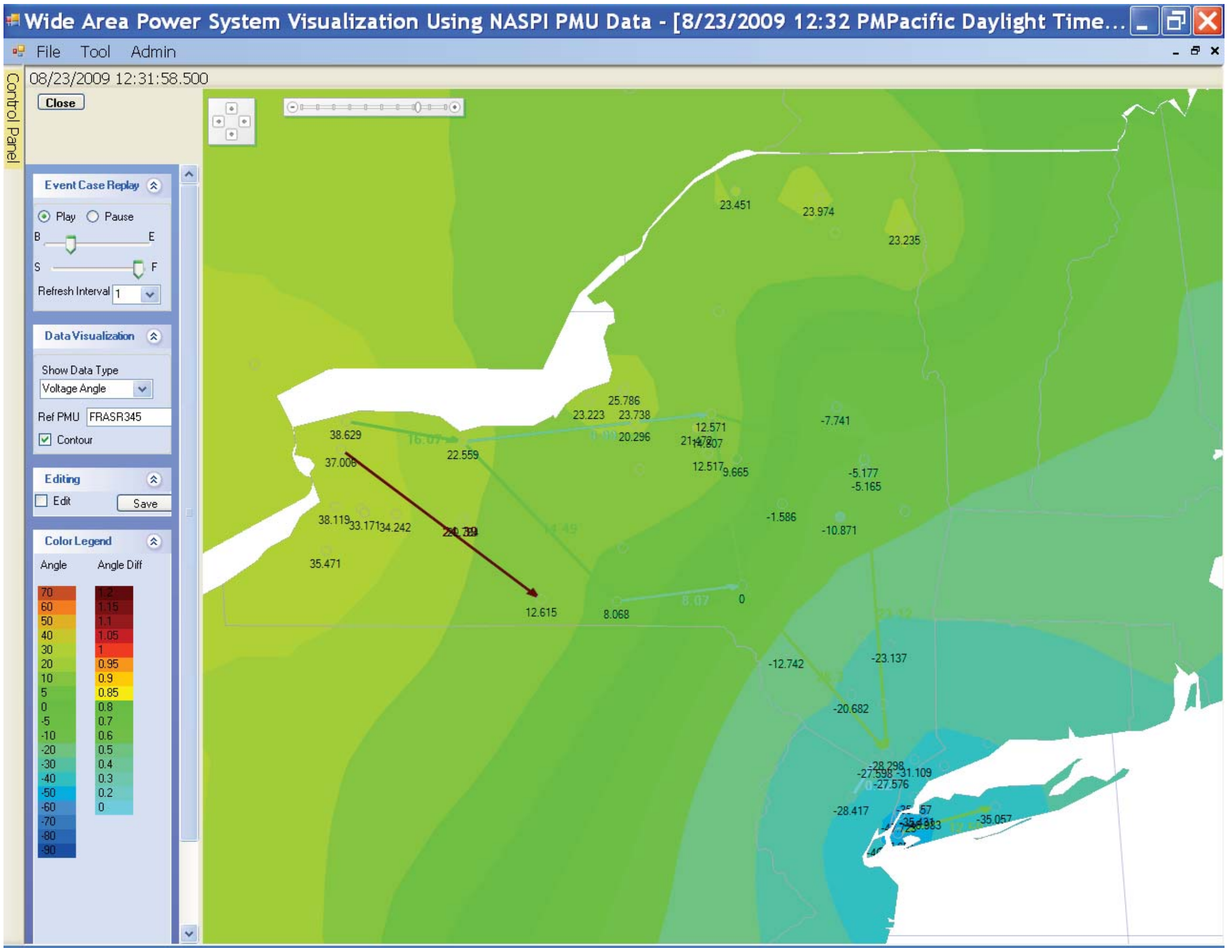


Figure 14 Phase angle display with angle of PMU at Fraser 345 selected as common reference

Trending Charts

The visualization application allows the user to select one PMU or a set of PMUs to show the trending charts. For a trending chart of synchrophasor measurements of one PMU as shown in Figure 16, the user can select two different types of measurements (primary and secondary measurements) to show on the trending chart as shown in Fig. 17. For a trending chart of synchrophasor measurements of two or more PMUs, the user can select one type of measurements of the selected PMUs or the angle differences to show on the trending chart as shown in Figure. 18. A checkbox of Auto Trending is provided for the user to show the latest synchrophasor measurements in real-time mode or during the event replay mode.

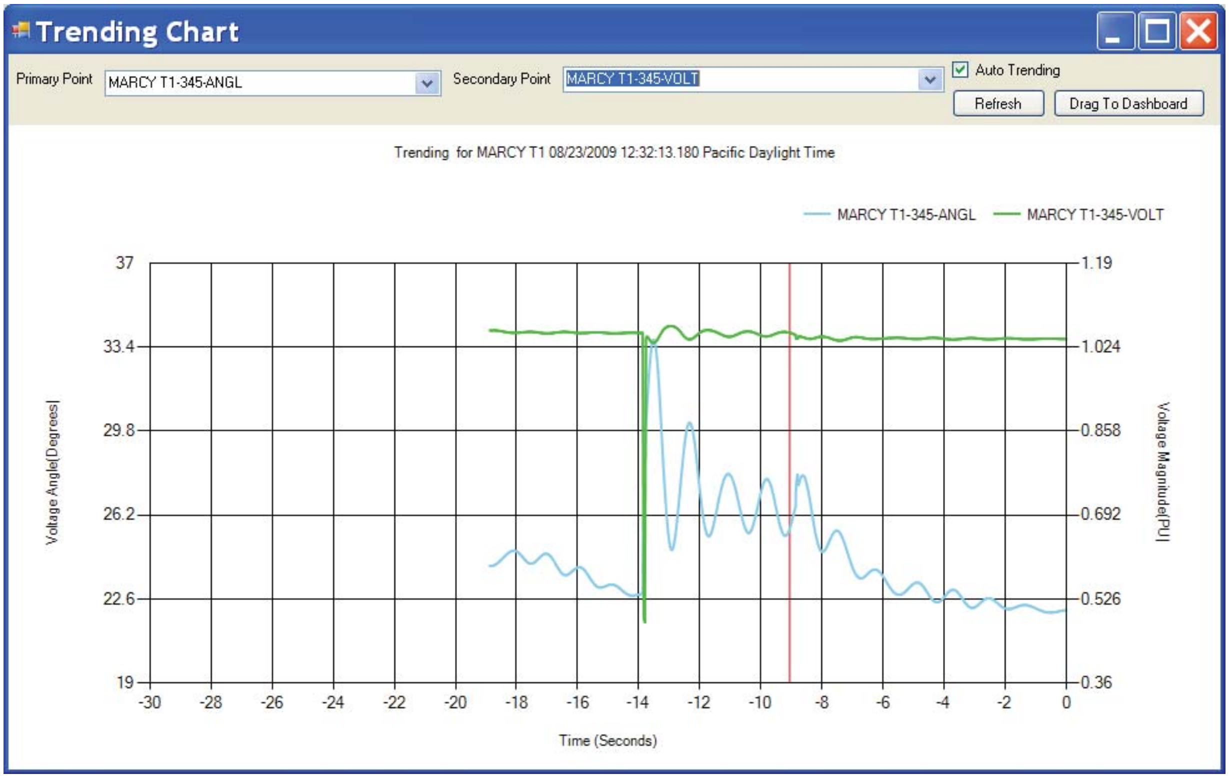


Figure 15 Synchrophasor Measurement Trending Chart for PMU at Marcy Station

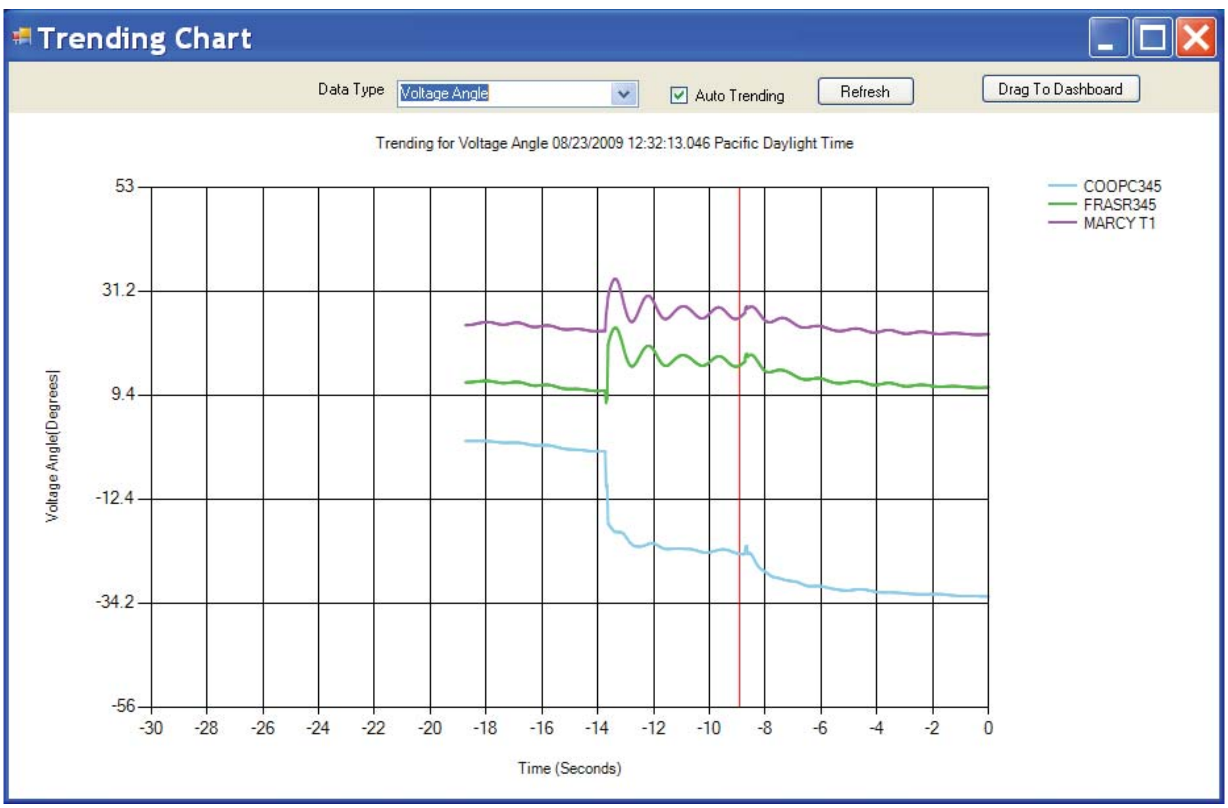


Figure 16 Synchrophasor Measurement Trending Chart for Several PMUs

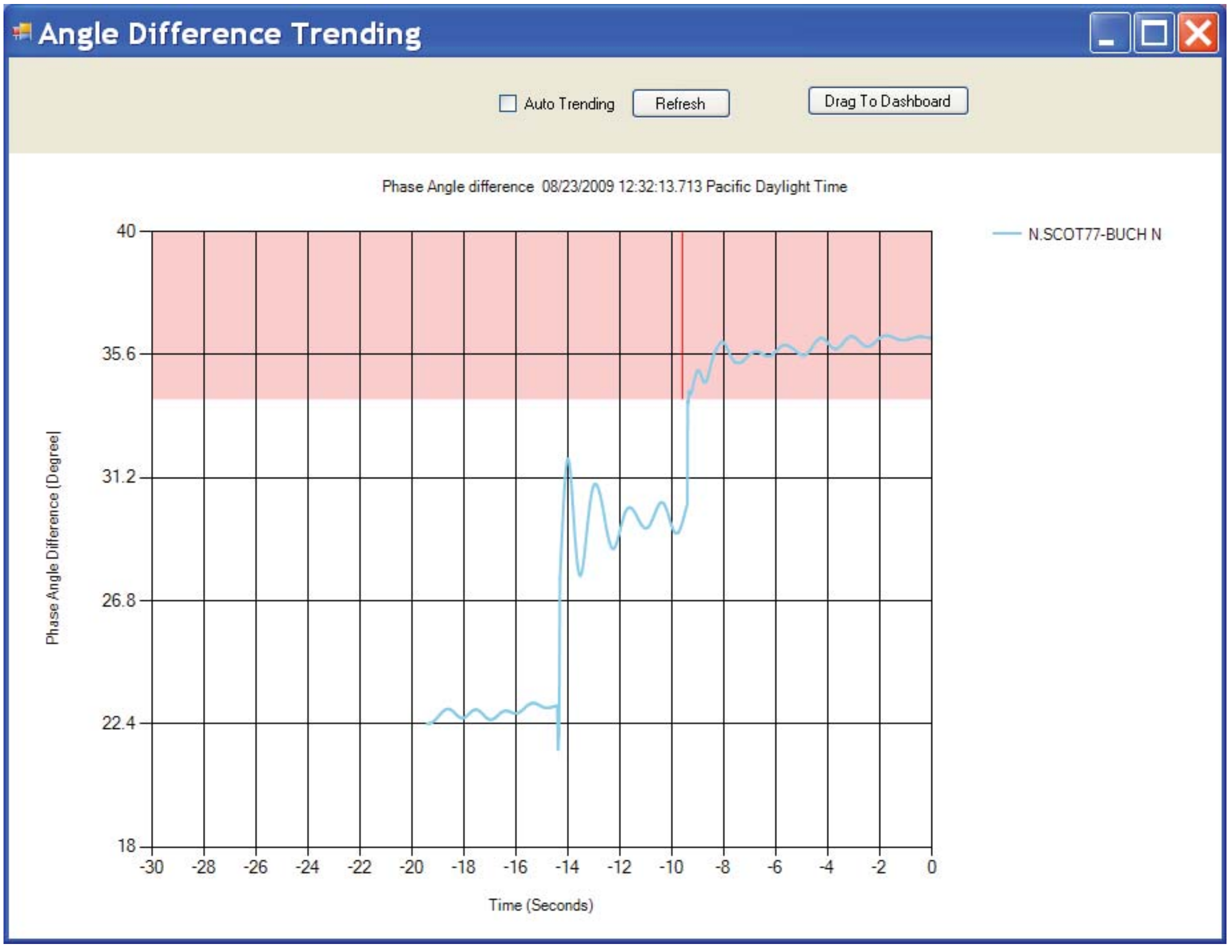


Figure 17 Trending Chart of Angle Difference between N. SCOT77 and BUCH N Substations

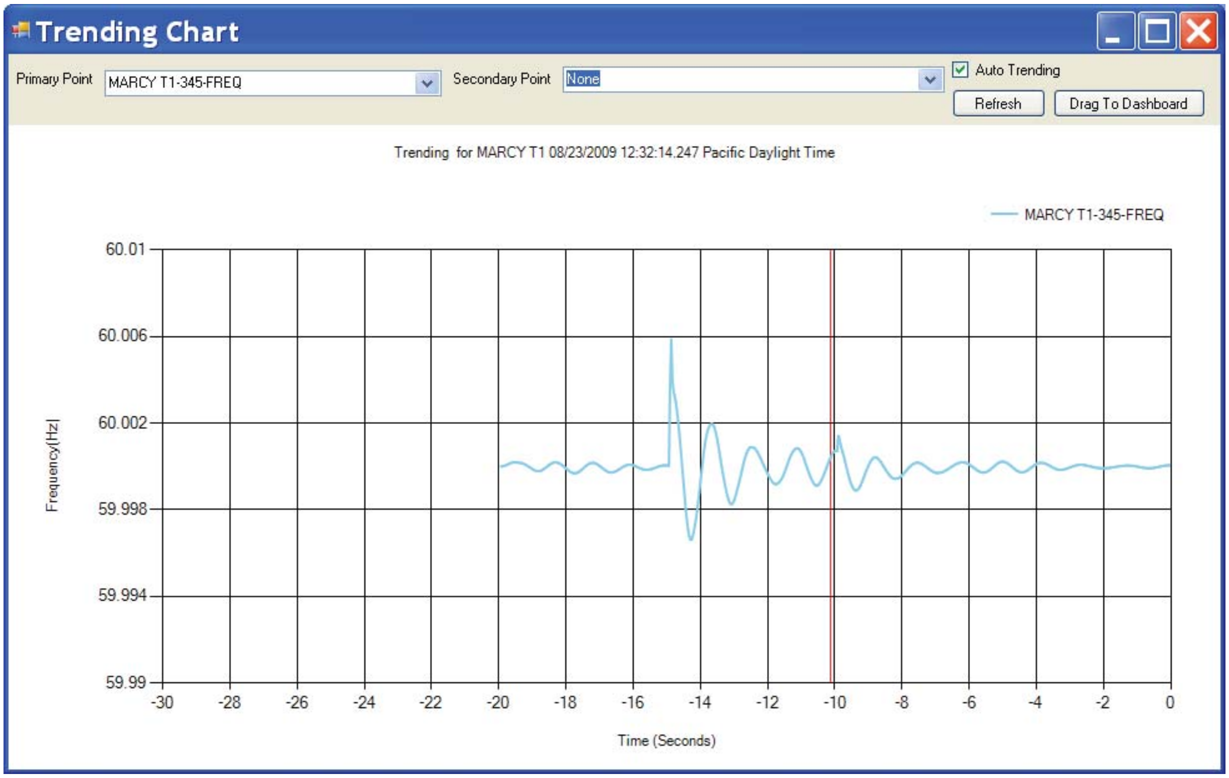


Figure 18 Trending Chart of Simulated Frequency Measurements of PMU at Marcy Substation

Dashboards

Dashboards were created using the button of "Drag to Dashboard" on a trending chart to drag the trending chart to selected dashboard. For the current version, three dashboard tabs were provided. For each dashboard tab, four dashboards were created for various types of trending charts including voltage magnitudes, phase angles, frequencies or angle differences of one or more than one synchrophasor measurements as shown in Figure 20 and Figure 21.

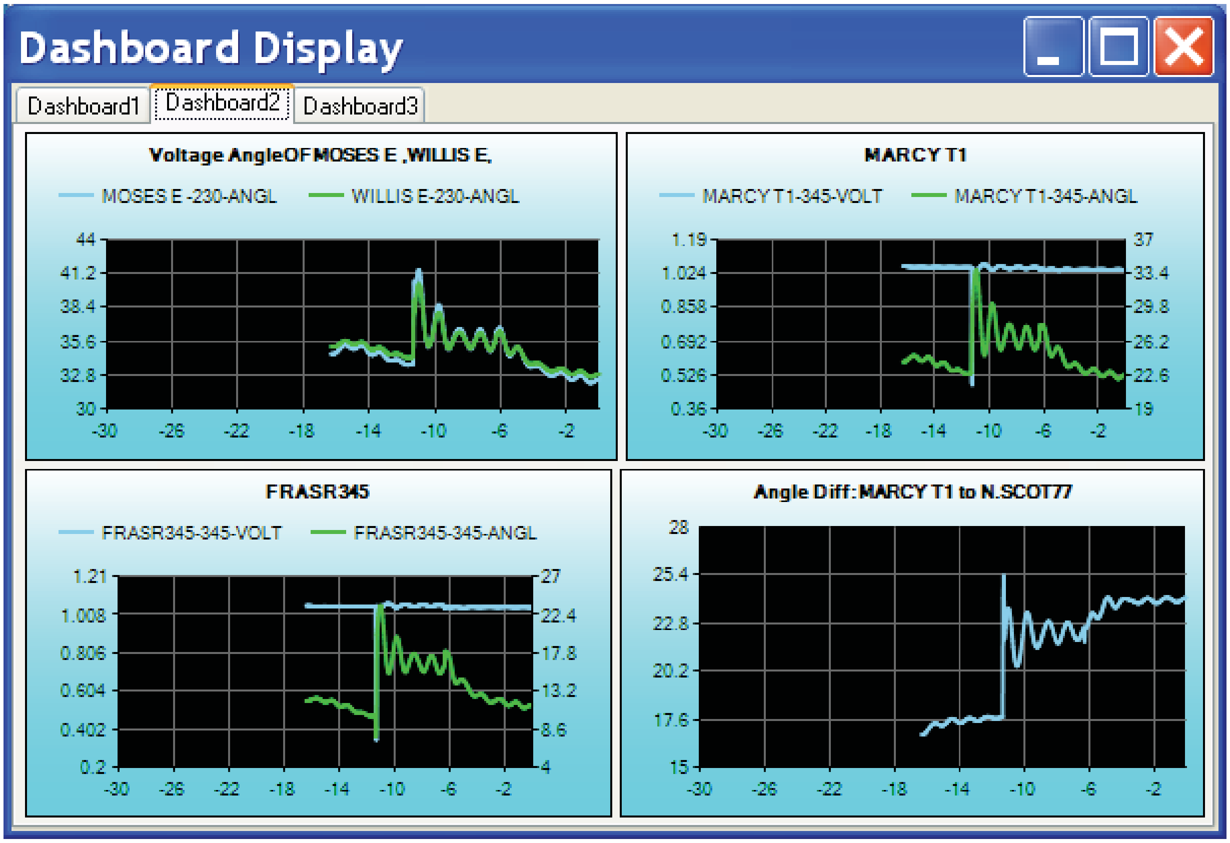


Figure 19 Dashboards for Reliability Monitoring Using Simulated Synchrophasor Measurements

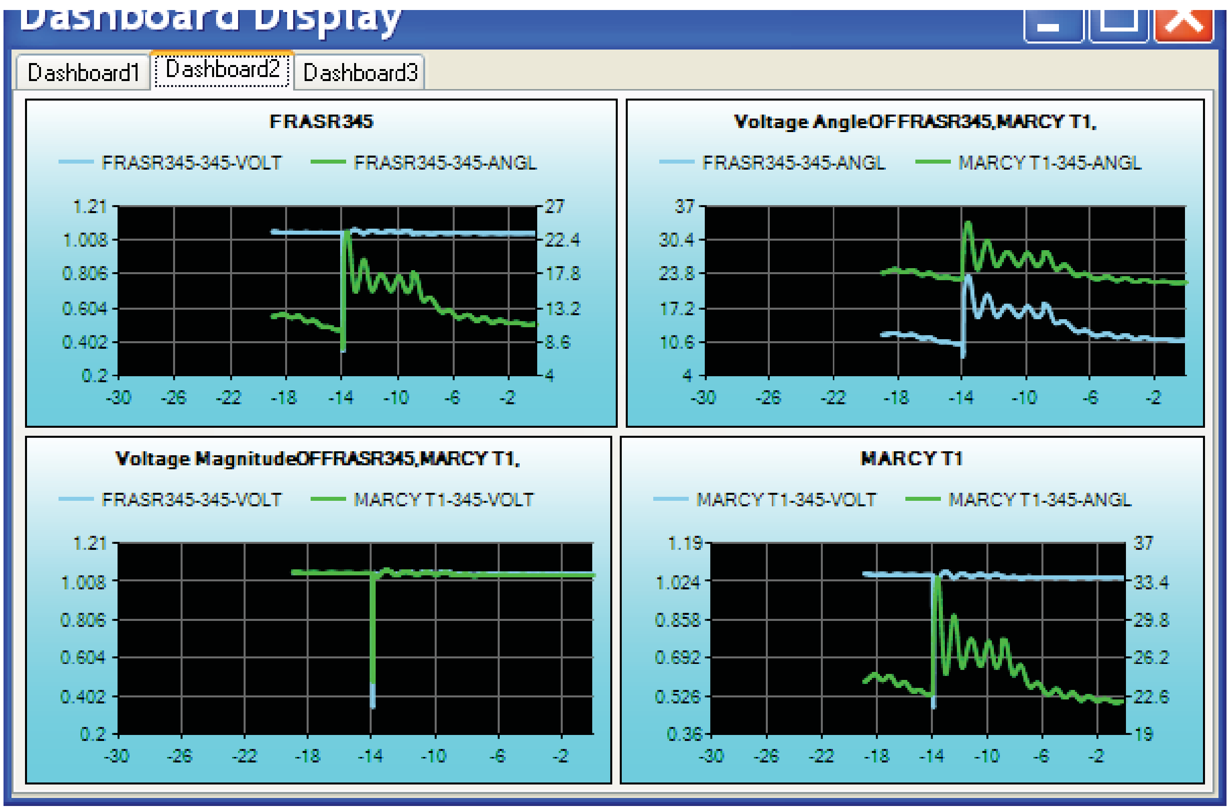


Figure 20 Dashboards for Reliability Monitoring Using simulated Synchrophasor Measurements

Tests Using Real-Time SynchroPhasor Measurements

This test was performed using the real-time PMU measurements of the Eastern Interconnection of the SPDC at TVA. The SPDC at TVA receives and processes the real-time synchrophasor measurements from more than 110 PMUs of the Eastern Interconnection. The screenshot of the voltage contour display with angle difference links is shown in Figure 10. The screenshot of the voltage contour display with angle difference links and zoomed in to the NYISO area is shown in Figure 11.

The screenshot of the phase angle contour display with angle difference links is shown in Figure 12. The screenshot of the phase angle contour display with angle difference links and zoomed in to the NYISO area is shown in Figure 13. The common reference angle was calculated based on the phasor angles of angle measurements of three TVA PMUs for each time frame.

The screenshot of the frequency contour display with angle difference links is shown in Figure 14. The screenshot of the frequency contour display with angle difference links and zoomed in to the NYISO area is shown in Figure 15.

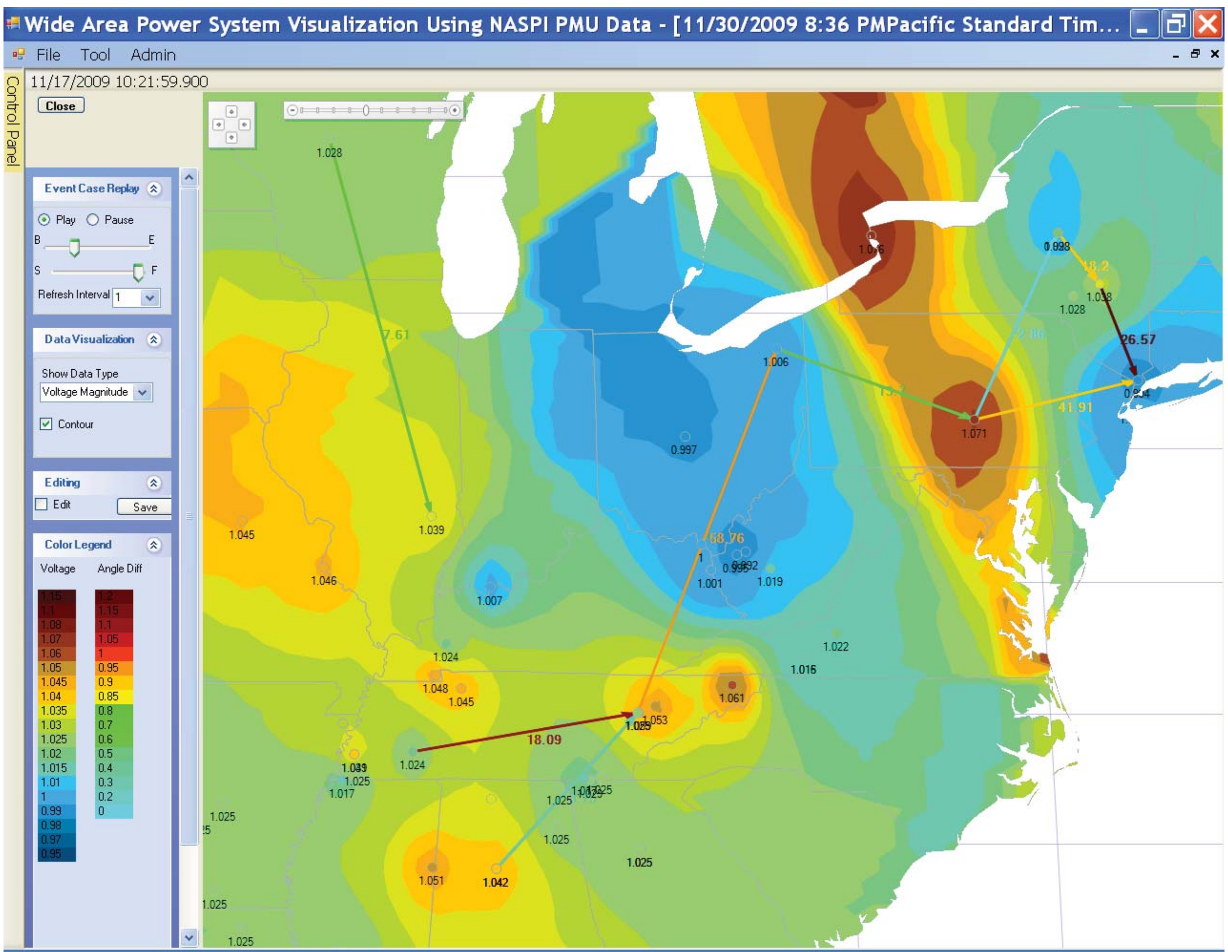


Figure 21 Voltage Contour Display using Real-Time SynchroPhasor Measurements

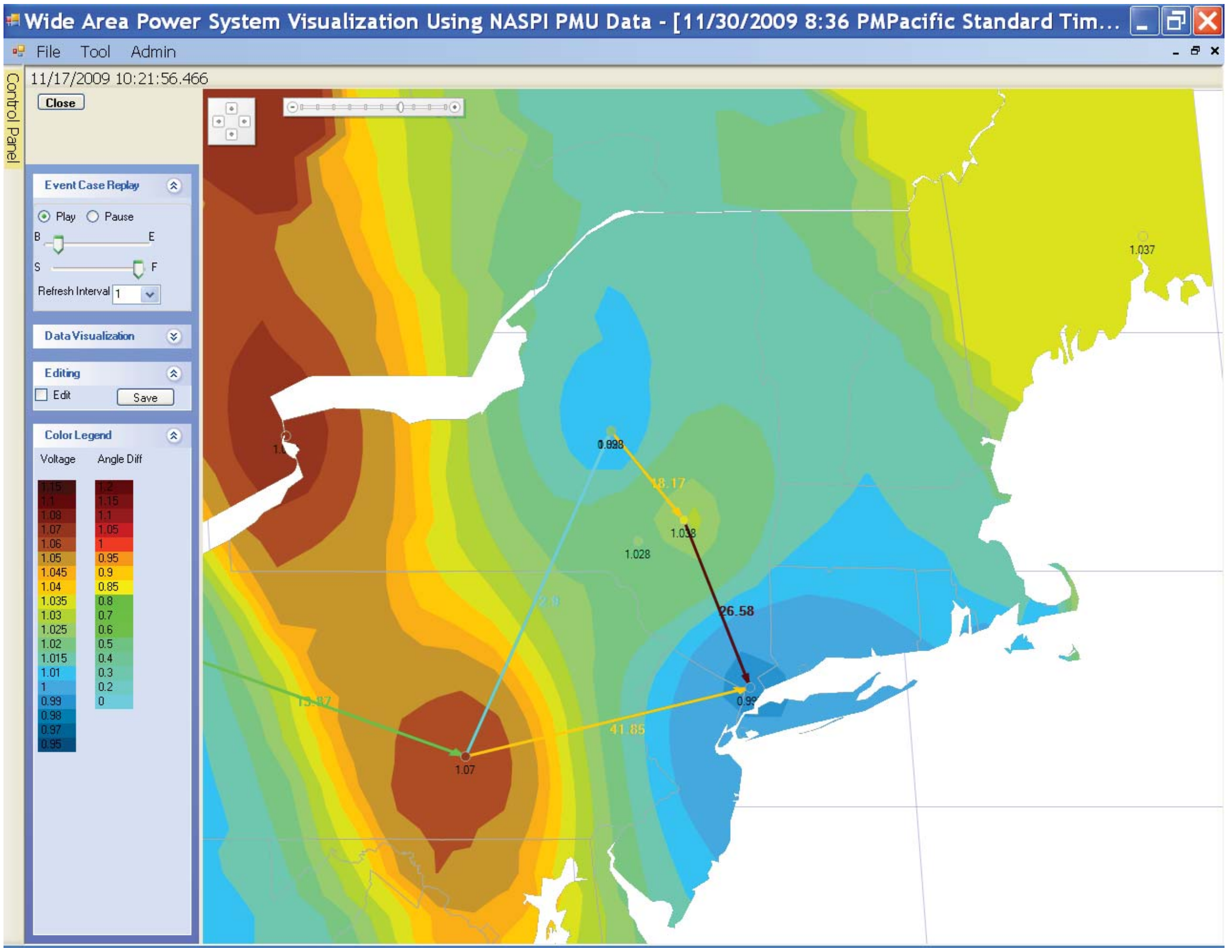


Figure 22 Voltage Visualization Display Using SynchroPhasor Measurements Zoomed in to NYISO Area

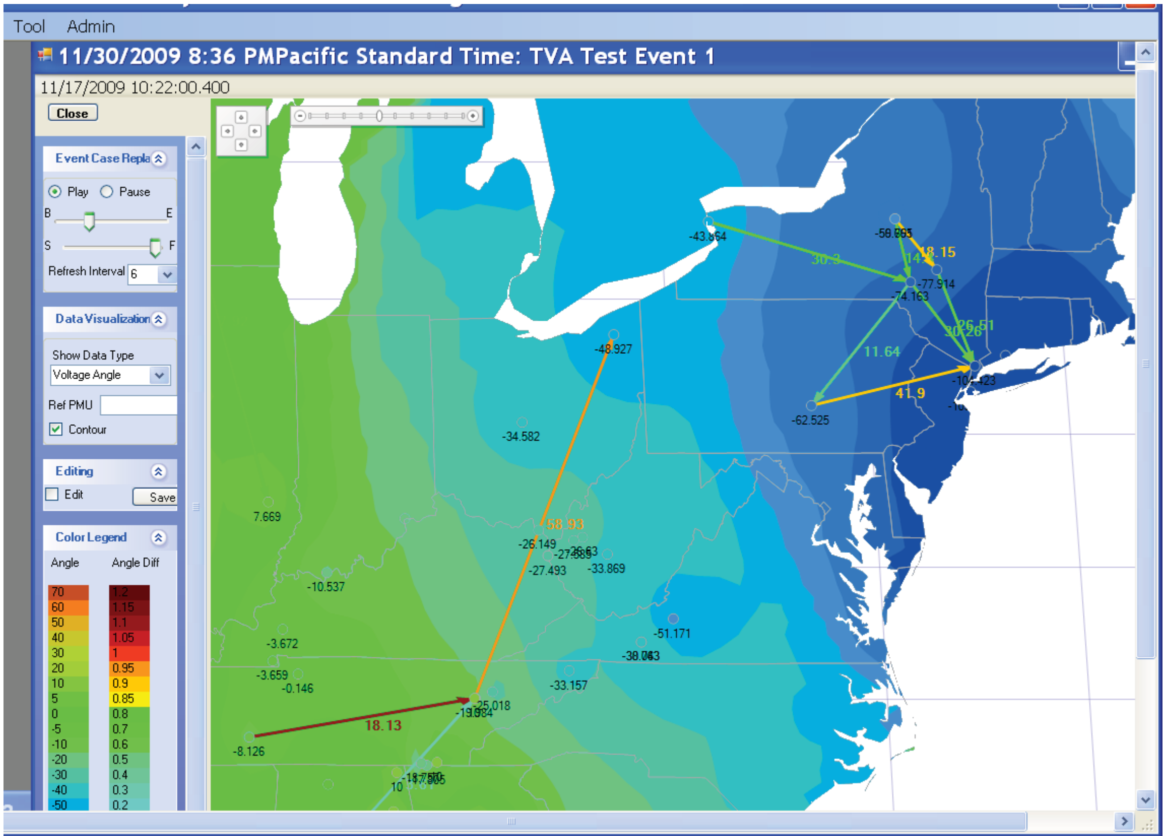


Figure 23 Phase Angle Visualization Display Using SynchroPhasor Measurements

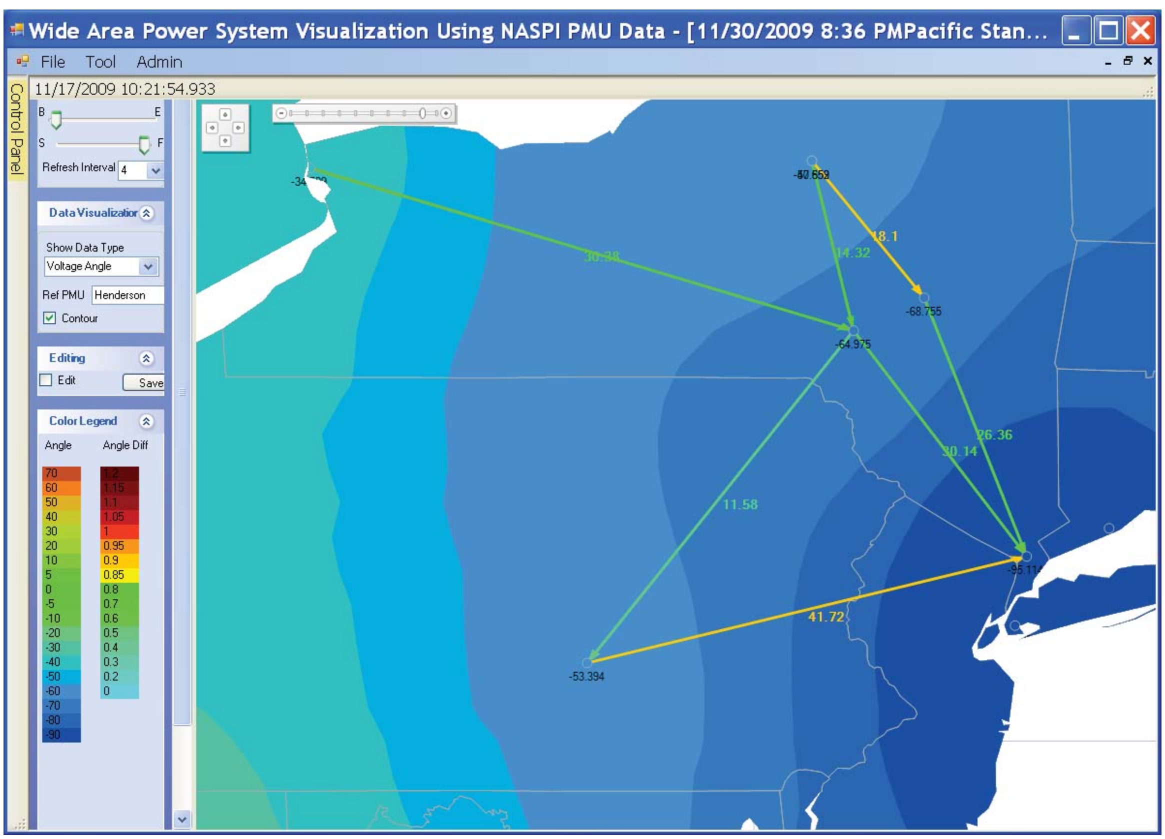


Figure 24 Phase Angle Visualization Display Using SynchroPhasor Measurements Zoomed in to NYISO Area

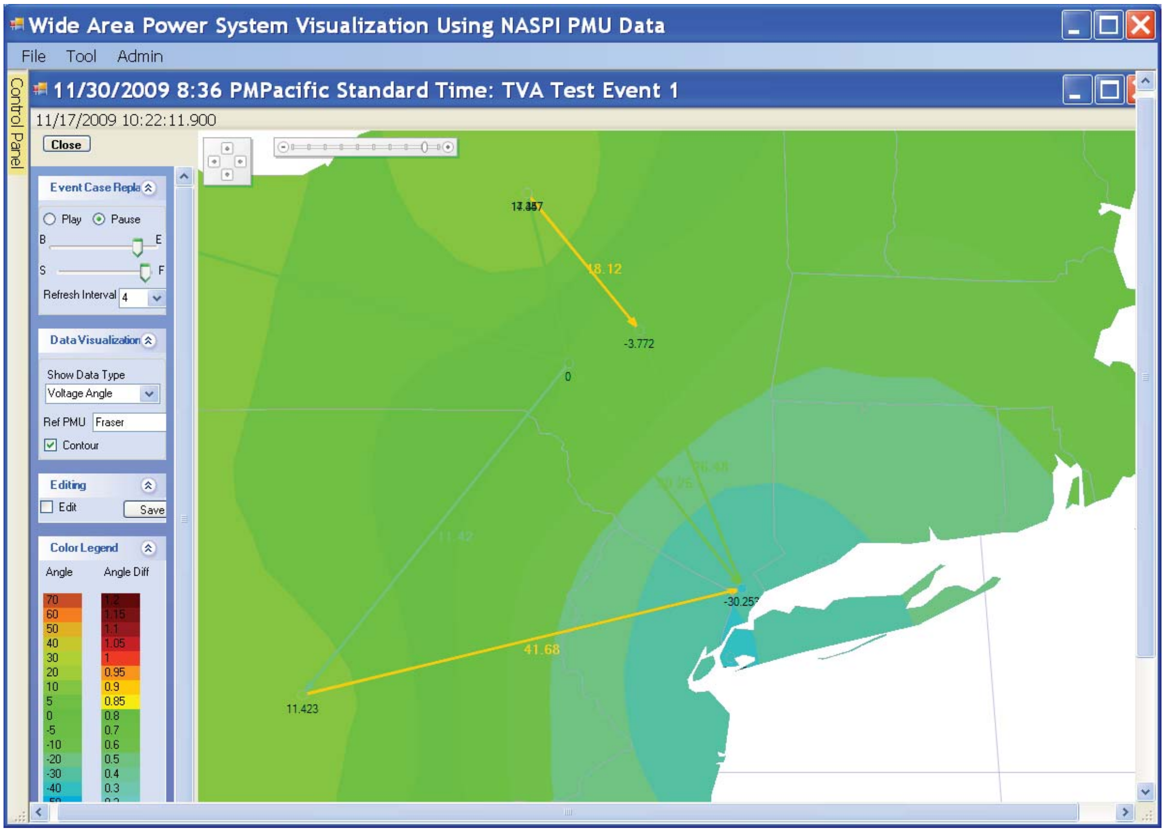


Figure 25 Phase Angle Visualization Display Using SynchroPhasor Measurements with User Selected Common Reference Angle

Figure 26 Frequency Visualization Display Using SynchroPhasor Measurements with Angle Difference Links

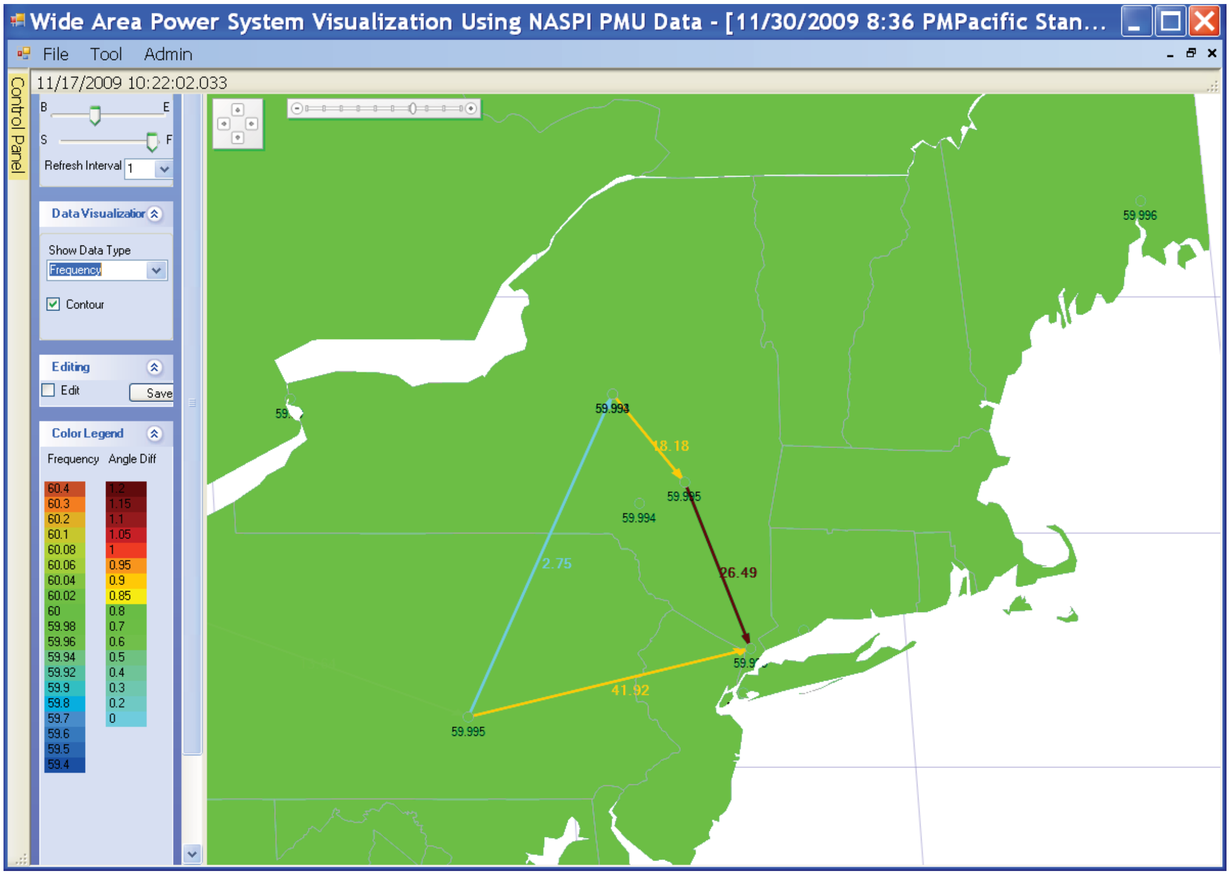


Figure 27 Frequency Visualization Display Using SynchroPhasor Measurements Zoomed in to NYISO Area

Testing Using FNET Frequency Measurements

The power system frequency contour display using FNET data with a generator outage event is shown in Figure 16.

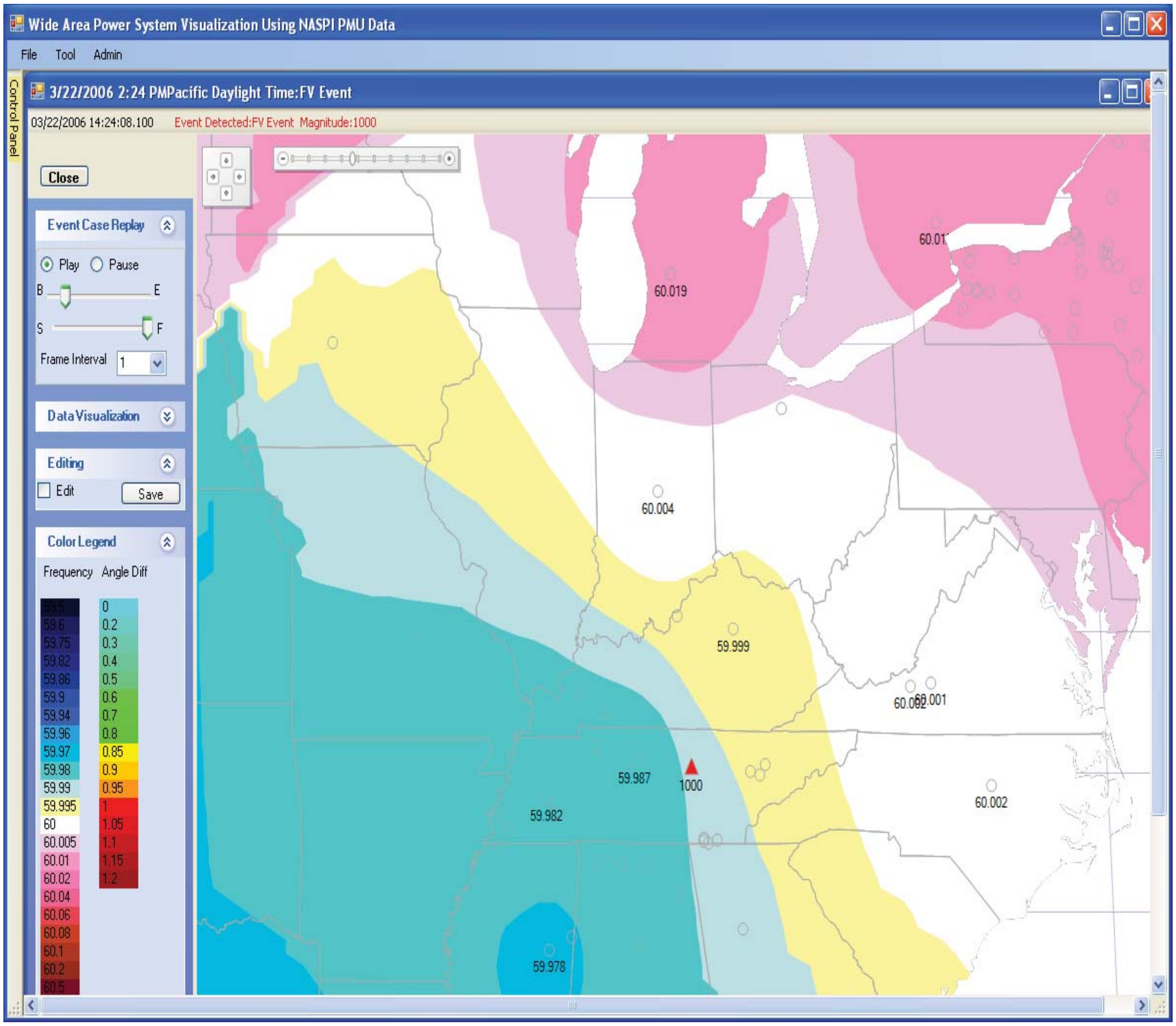


Figure 28 Frequency Contour Display Using FNET Event Data

This test was performed using the frequency measurements of the FNET for a generator outage event. When a large system event is detected and identified by the location of disturbance (LOD) function, the event location, the magnitude in MW and the related event message will be shown on the real-time frequency display. The frequency contour for a generator outage event is shown in Figure 16. The event location (triangular shape in red color), the event magnitude in MW and the event message are displayed immediately at the time (time 0) when the event occurred. Due to the sensitivity of the outage location of the event, the event location shown on the display was not the actual event location.

Future Work

The wide area power system visualization application using synchrophasor measurements described in this report has been developed and integrated with the Super Phasor Data Concentrator (SPDC) developed by TVA. Extensive tests have been performed using the real-time synchrophasor measurements of the Eastern Interconnection. EPRI received a DOE award in September of 2009 to perform research, development and large scale demonstration for wide area power system visualization, near real-time event replay and early warning of potential system problems using synchrophasor measurements. We are planning to work with TVA and Prof. Y. Liu of University of Tennessee to perform the research, development and demonstration of this new DOE project from 2009 to 2012. The large scale demonstration of this DOE synchrophasor technology demonstration project using the real-time and historical synchrophasor measurements of the Eastern Interconnection is expected to be completed in 2012.

Conclusions and Recommendations

A wide-area power system visualization application has been developed for reliability monitoring, near real-time event replay and post event analysis using real-time or historical synchrophasor measurements. This wide area power system visualization application has been tested extensively using simulated synchrophasor measurements. A prototype version of this application has also been integrated with the Super Phasor Data Concentrator (SPDC) at TVA for real-time reliability monitoring and near real-time event replay using the real-time synchrophasor measurements of the Eastern Interconnection for improving the situation awareness of power system operators and regional reliability coordinators. The initial results of the testing have been presented and discussed in this report. Smart Client technology is presented. This wide area power system visualization application can also show the location, magnitude and the related event message on the frequency display in real-time by integration with the on-line event triggering and location of disturbance applications. This application can fully uses the local computer resources and the Internet technology in order to meet the very challenging performance requirements to support large number of concurrent users and to provide hi-fidelity wide area power system visualization in real-time for large interconnected power systems. The Smart Client technology used for this power system visualization application significantly improves the performance by fully making use of the local computer resources, the Internet and the Web Services. The performance of this application has also been significantly improved by using the memory residence object oriented database and the advanced event oriented database to efficiently handle a large volume of real-time synchrophasor measurements; the event related measurements. The unique features of the near real-time event replay allow power system operators and reliability coordinators to monitor and analyze the new system event very shortly (a few seconds) after the event occurred allowing them to have time to prepare appropriate corrective or preventive control actions when necessary to prevent potential cascading outages.

This visualization application using Smart Client significantly simplifies the tasks of the software deployments, maintenance and update. The client version of the visualization application can be downloaded via the Intranet or secured Internet, and installed at user's computer in a few seconds. This visualization application can also be used for quickly identifying and correcting the various types of errors of the real-time synchrophasor measurements using the GIS based visualization contours displays.

References

[1] U.S.-Canada Power System Outage Task Force,"Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations", April, 2004.

[2] James Weber and Thomas Overbye, "Voltage Contours for Power System Visualization", IEEE Transaction on Power Systems, VOL. 15, NO. 1, February 2000.

[3] Tao Xia, Hengxu Zhang, Robert Gardner, Jason Bank, Jingyuan Dong, Jian Zuo, Yilu Liu, Lisa Beard, Peter Hirsch, Guorui Zhang, and Rick Dong, "Wide Area Frequency based Event Location Estimation", Presented at 2007 IEEE PES General Meeting,

[4] B. Qiu, L. Chen, V.A. Centeno, X. Dong, Y. Liu, "Internet Based Frequency Monitoring Network (FNET)", IEEE Power Engineering Society Winter Meeting, 28 Jan.-1 Feb. 2001, Vol. 3, pp 1166 – 1171.

[5] C. Maryinez, M. Parashar, J. Dyer, J. Coroas, "Phasor Data Requirements for Real Time Wide-Area Monitoring, Control and Protection Applications", EIPP White Report, January 26, 2005.

[6] "Eastern Interconnection Phasor Project (EIPP)", http://Phasors.pnl.gov/.

[7] ManuParashar, Jim Dyer and Terry Bike , "EIPP Real-Time Dynamics Monitoring System", http://certs.lbl.gov/certs-rt-pubs.html, February 2006

[8] G.Zhang, P. Hirsch and S. Lee, "Wide Area Power system visualization Using Smart Client Technology", Presented at 2007 IEEE PES General Meeting, Tampa, Florida, 2007.

[9] ManuParashar, Jianzhong Mo, "Real Time Dynamics Monitoring System (RTDMS): Phasor Applications for the Control Room," 42nd Hawaii International Conference on System Sciences, 2009

[10] Performance Requirements Task Team (PRTT), Eastern Interconnection Phasor Project, "Definition and Implementation of a System-Wide Phase Angle Reference for Real-Time Visualization Applications," October 13, 2005. Available at http://phasors.pnl.gov/resources_performance.html.

APPENDIX B

IDENTIFICATION OF CRITICAL VOLTAGE AREAS AND DETERMINATION OF REQUIRED REACTIVE POWER RESERVES FOR NEW YORK TRANSMISSION SYSTEM

NYSERDA AGREEMENT WITH ELECTRIC POWER RESEARCH INSTITUTE (EPRI) NO. 10470

FINAL TASK REPORT

Prepared for:

New York State Energy Research and Development Authority
Albany, NY

Project Manager
Michael P. Razanousky

Prepared by:
Electric Power Research Institute (EPRI)
3420 Hillview Avenue, Palo Alto, CA 94304

Project Managers
Dr. Stephen Lee and Dr. Liang Min

Task Manager
Dr. Kyeon Hur

Subcontractor:
Powertech Labs Inc.
12388-88th Avenue, Surrey, BC, Canada V3W 7R7

Project Manager
Dr. Ali Moshref

SEPTEMBER, 2010

Acknowledgements

The project was sponsored by the New York State Energy Research and Development Authority (NYSERDA) and was performed by the Electric Power Research Institute (EPRI).

The task for which this is the final task report was performed by Powertech Labs Inc. (Ali Moshref, Xianrong Wang, and Jahangir Khan).

This whole project has been conducted with support and advice by the following organizations: New York Independent System Operator, Consolidated Edison of New York, New York Power Authority, Long Island Power Authority, Central Hudson Gas and Electric Company, National Grid, and New York State Electric and Gas Company.

The contributions made by these participants are very much appreciated.

The suggestions and guidance of the NYSERDA Project Manager Michael P. Razanousky were particularly helpful.

Powertech Labs also extends special thanks to the EPRI Project Manager, Dr. Stephen Lee, the EPRI Program Manager Dr. Pei Zhang and Task Manager Dr. Kyeon Hur for their support in conducting this study.

Table of Contents

Section	Title	Page No.

List of Tables

Table Title Page No.

List of Figures

Figure Title Page No.

Executive Summary

Purpose of the Study

The objective of this project is to identify critical voltage control areas and determine the required reactive power reserves to maintain voltage stability for the New York electric power transmission systems. The areas, which are prone to voltage instability due to their lack of reactive power reserves, are referred to as Voltage Control Areas (VCAs). Once VCAs are identified, minimum reactive power reserve to maintain voltage stability (within the specified margins with given reactive reserve criteria) are determined. The Electric Power Research Institute (EPRI) contracted Powertech Labs Inc. (PLI) to carry out this research project.

EPRI Perspective

Assessing and mitigating voltage security issues are of vital importance to electric power system planners and operators. It is well understood that voltage security is driven by the adequacy level of reactive power support. Therefore, it is of particular interest to identify the areas in the system that may suffer reactive power deficiencies. The results presented in this report were obtained from a study with a limited scope, as this is a research project and not intended to be a comprehensive study. It was noted during this research project that one or more of the VCAs identified in this study is of a local nature. In practice, this study would be extended to reflect increased stress conditions such that a local problem may become a wider-area problem for which a practical VCA would be useful for managing voltage. Establishing the reactive power reserve requirements in these areas to ensure system integrity is of importance as well. Notice that these critical voltage control areas may change in shape and size for different system operations and contingency conditions. Thus, the analyses should be performed based on thorough understanding of the capabilities and limitations of the applied methodology, and working knowledge of the system of interest in reference to the project goals.

Approach, Methodology and Tools

The Electric Power Research Institute (EPRI) project (EP-P19261/C9512) (Ref.1,2) completed by Powertech Labs Inc. (PLI) produced a software framework capable of analyzing large complex power systems and establishing (i) areas prone to voltage collapse (i.e, Voltage Control Areas or 'VCAs'), (ii) the margin to instability for each VCA, (iii) the contingencies that lead to the collapse of each VCA, (iv) the generators that can control each VCA, and (v) the amount and generator allocation of reactive power reserves that must be maintained in order to ensure voltage stability. The software framework (VCA-Offline BETA) is now ready to be used in the analysis of large practical power systems.

The task of VCA identification is a very challenging problem primarily due to the fact that voltage security problem is highly nonlinear and VCAs may also change in shape and size for different system conditions and contingencies (Ref.3). To deal with these issues, a more practical approach was adopted by this project to clearly establish the VCAs for a given system under all system conditions. The approach is based on a PV Curve method combined with Modal Analysis. The general approach is as follows:

a) Define a system operating space based on a wide range of system load conditions, dispatch conditions, and defined transactions (source-to-sink transfers)
b) Define a large set of contingencies that spans the range of credible contingencies
c) Using PV curve method, push the system through every condition, under all contingencies until the voltage instability point is found for each condition
d) At the point of instability for each case (nose of the PV curve), perform modal analysis to determine the critical mode of instability as defined by a set of bus participation factors corresponding to the zero eigenvalue
e) Store the results of the modal analysis in a database for analysis using data mining techniques to identify the VCAs and track them throughout the range of system changes
f) Establish the reactive reserve requirements for each identified VCA

The VCA-Offline BETA application runs on Powertech Labs Inc.'s VSAT (Voltage Security Assessment Tool) engine, requires MS Access 2007, and operates on MS Windows XP platform.

Results

The NYISO voltage critical area (VCA) identification study considers a set of three powerflow basecases (Summer-peaking, winter-peaking, and light load for year 2012), four cross-state transfer scenarios, and a number of pre-defined as well as N-1 contingencies. EPRI/Powertech's VCA-Offline BETA program has been used in identifying the VCAs and corresponding reactive reserve requirements.

This software tool has revealed a total of four VCAs, which are[1]:

- VCA#1: Located near Station EST_XX (Area 1XX0, Area 1XX5, Owner CXXD)
- VCA#2: Located near Station FRG_XX (Area 1XX0, Area 1XX5, Owner CXXD)
- VCA#3: Located near Station ERV_XX (Area 1XX0, Area 1XX5, Owner CXXD)
- VCA#4: Located near Station KNC_XX (Area 6XX, Zone 2XX1, Owner NXXG)

The required reactive power to maintain on the generators that control voltage stability in the above weak areas (with required stability margin of 5%) varies for each area. Also, it is important to note that since VCA 2, 3, and 4 have very high margins (>22%), there is no need to specify any reactive power requirement for them. The required reactive power of the controlling generators in the weak area 1 (VCA #1) is approximately 230 MVAR. It is also important to consider how many contingencies are supporting a specific VCA when the reactive power requirement is being sought. An example is the VCA #4. In this VCA there are 34 buses with one controlling generator. This VCA is only supported by one contingency.

Pursuant discussions have revealed that:

[1] Proprietary information has been masked and further details are given in Section A-4.

- considering the geographical proximity and network configurations, VCA#1, #2, and #3 can apparently be treated as a single VCA
- considering the fact that VCA#4 is reflective of a local load distribution issue, this VCA can be ignored

It has also been observed that the current VCA-Offline BETA program needs to be advanced such that elements of utility owner/operator's experience can be incorporated into the program intelligence.

Future Work

Even with significant due-diligence efforts in correcting the powerflow basecases, setting the scenarios, and inspecting the outcomes, the results of this study may contain inconsistencies with system operator/owners' experience and knowledge. Possible future activities in this regard include:

- Develop interpretations of this study through system operator/owners' experience
- Advance the VCA-Offline BETA application to a more robust and faster product
- Conduct further study on the NYISO system (with inter-state transfers and reduced powerflow basecases.

Section 1: Background

Assessing and mitigating problems associated with voltage security remains a critical concern for many power system planners and operators. Since it is well understood that voltage security is driven by the balance of reactive power in a system, it is of particular interest to find out what areas in a system may suffer reactive power deficiencies under some conditions. If those areas prone to voltage security problems, often called Voltage Control Areas (VCA), can be identified, then the reactive power reserve requirements for them can also be established to ensure system secure operation under all conditions.

A number of attempts have been made in the past to identify those areas, including a wide range of academic research and efforts toward commercial applications. A brief review of methods for determining VCA groups is presented in the following.

Robert A. Schlueter (Ref.4) suggested that there are two main types of voltage instability

- Loss of voltage control instability, which is caused by exhaustion of reactive supply with consequent loss of voltage control on a particular set of reactive sources such as generators, synchronous condensers, or other reactive power compensating devices.
- Clogging voltage instability that occurs due to I^2X series inductive reactive power usages, tap changer limits, switchable shunt capacitors limits, and shunt capacitive reactive supply reduction due to decreasing voltage.

Clogging voltage instability usually occurs in distribution networks when the excessive inductive reactive power chokes off the reactive flow to those sub-regions. It can take place even without any exhaustion of reactive reserves. While clogging instability does not occur due to loss of voltage control, the loss of voltage control can contribute to the cause of clogging instability (Ref.4).

The VSSAD method (Ref.4) breaks up any power system into non-overlapping set of coherent bus groups (VCAs), with unique voltage stability problems. There is a Reactive Reserve Basin (RRB) associated with each VCA, which is composed of the reactive resources on generators, synchronous condensers, and other reactive power compensating devices, such that its exhaustion results in voltage instability initiated in this VCA. The VCA bus group acts like a single bus and can't obtain reactive power supply at the same level of reactive power load no matter how it is distributed among the buses in that group.

Finding VCAs and their associated RRB's in VSSAD method is based on VQ curve analysis performed at each test VCA. It involves the placement of a synchronous condenser with infinite limits at VCA buses and observing the reactive power generation required for different set point voltages.

VQ curve analysis can be time consuming if curves have to be found for every bus in the system. Thus another method has been proposed by Schlueter et.al. (Ref.10,11), which reduces the number of VQ curves that need to be found for determining system's RRBs. Coherent bus groups can be found by this method that have similar VQ curve minimas and share a similar set of exhausted generators at these minimas. This method, however, involves a fairly high degree of trial and error and requires the computation of VQ curves at higher voltage buses before the VQ curves for each individual bus group can be found.

An alternative method for determining the VCA groups was proposed in (Ref.6) without the need for VQ curves to be computed beforehand. The proposed sensitivity-based method ensures that buses grouped together have the same RRB generators, provided they are reactive power reserve limited. By determining what buses have similar generator branch sensitivities, it is possible to determine coherent groups of buses that will have the same RRB.

This method had been questioned in (Ref.12) based on the argument that the generator branch sensitivities are not expected to remain the same for a change in operating condition or network topology. Another method was proposed there using, full Jacobian sensitivities, along with bus voltage variations under contingencies.

A group of proposed methods, which are variations of the Schlueter's algorithm, rely on finding the weakest transmission lines connected to each bus. Those methods, such as Zaborszky's Concentric Relaxation method (Ref.15) are discussed to a great extent in Ref.7. Another method of this kind was proposed in Ref.8 and it is based on the concept of "bus through flow". Bus static transfer stability limits are found when bus complex through flow trajectories become vertical. Those buses form topological cuts, which are connected to the rest of the system by "weak" boundaries.

A Q-V sensitivity based concept of electrical distance between two buses was introduced in 1989 by Lagonotte Ref.14. The attenuation of voltage variation was defined as a ratio of the off-diagonal and the diagonal elements of the sensitivity matrix. Several algorithms were proposed (Ref.91314) based on this concept of electrical distance for separating VCA groups.

A modal analysis technique has been applied to evaluate voltage stability of large power systems (Ref.16). Although it has proven, when combined with PV analysis, to be an effective tool for determining areas prone to voltage instability for individual selected system scenarios, it has not been used directly as an approach to automatically determine VCAs when numerous contingencies or system scenarios are involved.

In summary, the existing methods have had only a limited success in commercial application because they cannot produce satisfactory results for practical systems. This, in general, is because of the following difficulties

(a) The problem is highly nonlinear. To examine the effects of contingencies, the system is repeatedly stressed in some manner by increasing system load and generation. The process of stressing the system normally introduces a myriad of nonlinearities and discontinuities between the base case operating point and the ultimate instability point

(b) The VCAs must be established for all expected system conditions and contingencies; Finding VCAs is a large dimensioned problem because many system conditions and contingencies need to be considered. It may not be possible to identify a small number of unique VCAs under all such conditions. The VCAs may also change in shape and size for different conditions and contingencies.

To deal with those issues, a more practical approach is needed that can clearly establish the VCAs for a given system and all possible system conditions.

Section 2: Project Objectives

The objectives of this project are,

(a) Identification of Critical Voltage Areas in New York Transmission System
(b) Determination of minimum reactive power reserve to maintain voltage stability with specified margin given the reactive reserve criteria.

This project is not intended to address the issue of the proportional requirements for static vs. dynamic Vars needed in each VCA. This mix depends on the nature of the instability and the characteristics of load and system components, and can only be properly established by using time-domain simulations.

Also, the focus of this project is on developing an approach that is suitable for use in the off-line (i.e. system planning) environment in which many scenarios spanning a given planning horizon must be examined. In this environment the volume of analysis may be much higher than in the on-line environment, but computation time, though always important, is not a mission critical requirement as in the case of on-line analysis. The issue of on-line VCA determination will be addressed in the next phase of the project.

Section 3: Proposed Approach – Modal Analysis

The proposed approach is based on a *PV Curve method* combined with *Modal Analysis.* The general approach is as follows,

(a) A system operating space is defined based on a wide range of system load conditions, dispatch conditions, and defined transactions (source-to-sink transfers).
(b) A large set of contingencies is defined, which spans the range of credible contingencies.
(c) Using PV curve methods, the system is pushed through every condition, under all contingencies until the voltage instability point is found for each condition.
(d) To identify the VCA for each case using modal analysis At the point of instability for each case (nose of the PV curve) modal analysis is performed to determine the critical mode of instability as defined by a set of bus participation factors corresponding to the zero eigenvalue (bifurcation point).
(e) The results of the modal analysis will is placed in a database for analysis using data mining methods to identify the VCAs and track them throughout the range of system changes.
(f) The reactive reserve requirements for selected VCA will then be established.

In this report an overview of V-Q sensitivities and modal analysis are presented. While the concept of V-Q sensitivity is a familiar one (the effect on voltage of a reactive injection at a bus), the concept of modal analysis, as used to determine area prone to voltage instability, is less widely understood. Therefore, it is useful to relate the two concepts to classify the meaning of modal analysis results.

The network constraints are expressed in the following linearized model around the given operating point (Ref.17)

$$\begin{bmatrix} \Delta P \\ \Delta Q \end{bmatrix} = \begin{bmatrix} J_{P\theta} & J_{PV} \\ J_{Q\theta} & J_{QV} \end{bmatrix} \begin{bmatrix} \Delta\theta \\ \Delta V \end{bmatrix} \quad \text{.......................................} \; 3\text{-}1$$

Where

ΔP – incremental change in bus real power
ΔQ – incremental change in bus reactive power
$\Delta\theta$ – incremental change in bus voltage angle
ΔV – incremental change in bus voltage magnitude
$J_{P\theta}$, J_{PV}, $J_{Q\theta}$, J_{QV} – are Jacobian sub-matrices

The elements of the Jacobian matrix give the sensitivity between power flow and bus voltage changes. While it is true that both P and Q affect system voltage stability to some degree, we are primarily interested in the dominant relationship between Q and V. Therefore, at each operating point, we may keep P constant and evaluate voltage stability by considering the incremental relationship between Q and V. This is not to say that we neglect the relationship between P and

V, but rather we establish a given P for the system and evaluate, using modal analysis, the Q-V relationship at that point.

Based on the above consideration the incremental relationship between Q and V can be derived from Equation 3-1 by letting ΔP=0

$$\Delta Q = J_R \cdot \Delta V \quad \text{.......} \quad 3\text{-}2$$

Where J_R is the reduced Q-V Jacobian sub-matrix

$$J_R = \left[J_{QV} - J_{Q\theta} J_{P\theta}^{-1} J_{PV} \right] \quad \text{.......} \quad 3\text{-}3$$

From Equation 3-2 we can write:

$$\Delta V = J_R^{-1} \cdot \Delta Q \quad \text{.......} \quad 3\text{-}4$$

Where the inverse matrix J_R^{-1} is the V-Q sensitivity matrix

$$J_R^{-1} = | \partial V / \partial Q | \quad \text{.......} \quad 3\text{-}5$$

The i^{th} diagonal element of matrix J_R^{-1} is the V-Q sensitivity at bus i, which represents the slope of the Q-V curve at the given operating point. A positive V-Q sensitivity is indicative of stable operation the smaller the sensitivity the more stable the system. The sensitivity becomes infinite at the stability limit.

Sensitivity matrix J_R^{-1} is a full matrix whose elements reflect the propagation of voltage variation through the system following a reactive power injection in a bus.

V-Q sensitivity Analysis

V-Q sensitivities provide information regarding the combined effects of all modes of voltage reactive power variations. The relationship between bus V-Q sensitivities and eigenvalues can be derived from the general Equation 3-4. Using the eigenvalues and eigenvectors of the reduced Jacobian matrix J_R we can write

$$J_R = \mathrm{E} \Lambda n \quad \text{.......} \quad 3\text{-}6$$

Where

$E = \left[E_1, E_2, \ldots, E_N \right]$ is the right eigenvector matrix of J_R

$E = [E_1, E_2, ..., E_N]^T$ is the left eigenvector matrix of J_R

is the eigenvalue matrix of J_R

Since = $^{-1}$ we can also write

$$J_R^{\ 1} = \quad {}^{1}$$ 3-7

Substituting Equation 3-6 in Equation 3-4 gives

$$\Delta V = \quad {}^{1} \quad \Delta Q$$ 3-8

or

$$\Delta V = \sum_i \frac{\ _i \ \ _i}{\lambda_i} \Delta Q$$ 3-9

where λ_I is the i^{th} eigenvalue of J_R and $_i$ and $_i$ are its corresponding right and left eigenvectors. Bus V-Q sensitivities can be derived from Equation 3-9 as follows. Let $\Delta \boldsymbol{Q} = \mathbf{e}_k$ where e_k has all zero elements except for the k^{th} element that is equal to 1. The V-Q sensitivity at bus k is then given by

$$\frac{\partial V_k}{\partial Q_k} = \sum_i \frac{\ _{ki} \ \ _{ik}}{\lambda_i}$$ 3-10

Where $_{ki}$ and $_{ik}$ are the k^{th} elements of the right and left eigenvectors respectively corresponding to eigenvalue λ_i.

The V-Q sensitivities provide information regarding the combined effects of all modes on voltage-reactive power variation. The magnitudes of the eigenvalues can provide a relative measure of the proximity to voltage instability.

When the system reaches the voltage stability critical point, the modal analysis is helpful in identifying the voltage stability critical areas and buses, which participate in each mode. The relative participation of bus k in mode i is given by the bus participation factor

$$P_{ki} = \ _{ki} \ \ _{ik}$$ 3-11

From Equation 3-10 we could see that bus participation factor P_{ki} determines the contribution of eigenvalue λ_i to the V-Q sensitivity at bus k.

Section 4: VCA Identification Method

The proposed approach is based on PV Curve and Modal Analysis methods presented in the previous section.

In the proposed approach, the power system is stressed to its stability limit for various system conditions under all credible contingencies. At the point of instability (nose of the PV curve) modal analysis is performed to determine the critical mode of voltage instability for which a set of bus participation factors (PF) corresponding to the zero eigenvalue (bifurcation point) is calculated. Based on these PFs, the proposed method identifies the sets of buses and generators that form the various VCAs in a given power system.

It is assumed that for a given contingency case, buses with high PFs including generator terminal buses, form a VCA. This suggests that each contingency case might produce its own VCA. In practice, however, the large number of credible contingency cases generally will produce only a small number of VCAs because several contingencies are usually related to the same VCA. The proposed identification procedure applies heuristic rules to (a) group contingencies that are related to the same VCA; and (b) identify the specific buses and generators that form each VCA (see Figure 4-1).

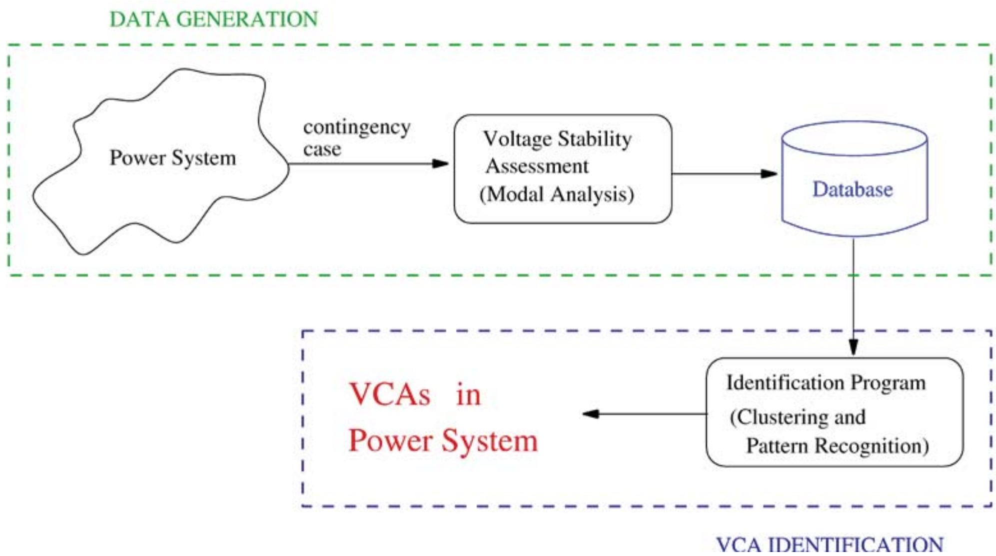


Figure 4-1 VCA identification in a Power System

The following is a brief description of the proposed VCA identification program. The program processes the sets of buses and generators corresponding to the PFs obtained from the Modal Analysis for each system condition and contingency case. Then contingency cases are grouped together if their sets of bus PFs are similar. To carry out this contingency clustering process, first a 'base/seed' set of VCA buses is selected. Then, all the other sets corresponding to different contingency cases are compared against this base set to determine if they are similar. Contingencies are clustered if their sets of bus PFs are similar. Finally, the program identifies the sets of buses and generators that are common to all contingencies of each cluster. Those sets of buses and generators form the VCAs of the power system.

Automatic Generation of Scenario Cases

The VSAT program is used to simulate the scenarios and to compute PV curves for all transfers and contingencies. The objective is to stress the system in the manner specified by the given transfer and to perform modal analysis at the nose point of the PV curve.
Modal analysis outputs include the following:

- Critical mode eigenvalues
- Critical mode bus participation factors
- Generator status (flagged buses with generators at reactive power limit)

A program was developed for automatic generation and simulation of single-contingency cases for a given scenario. This program breaks down the list of contingencies included in a scenario data file, generates single-contingency scenarios, and runs VSAT simulation for those single-contingency cases by stressing the system and performing modal analysis at the last voltage stable transfer. All generated output files are collected for post-processing in order to generate the database (DB) records for the VCA identification engine.

VCA Identification Process

The VCAs are identified based on the results of the analysis of all credible contingencies and different power system conditions. Each VCA identified is related to a cluster of contingencies; these cases are the so-called "support" of that VCA. This means that first "similar" contingency cases are clustered and then the *specific* buses and generators that form the VCAs are identified. Before clustering contingency cases, however, a preliminary selection of buses and generators is done at an earlier stage of the VCA identification process as indicated in Figure 4-2.

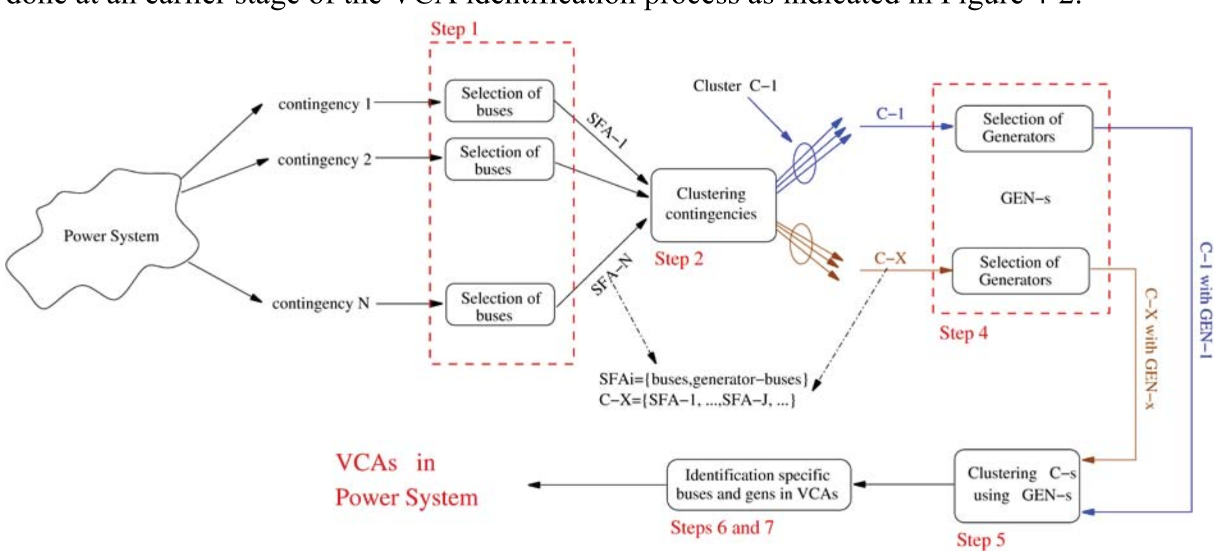


Figure 4-2 Steps in the VCA identification Process

The VCA identification process consists of the following steps:

1. Selection of Buses for VCA Identification

From individual contingency modal analysis results, a subset of buses with high PF is selected for further analysis (remaining buses are discarded). Several strategies to select such subset can be applied. For instance, one could predefine a PF threshold and then select the buses with PFs above this threshold. Such approach would assume that it is meaningful to compare PFs values among various contingencies. Nevertheless, such assumption may be false because the PFs calculated for each contingency are normalized with respect to the maximum PF value of each mode. Therefore, because different contingencies use different references for their PFs, they cannot be compared.

Since each contingency case is unique, a better approach to select the Set for Further Analysis (SFA) buses is to base it on the characteristics of each contingency. Generator terminal buses are PV type buses and thus are not included in the reduced Jacobian matrix. Therefore, PF cannot be calculated for a generator terminal bus until the generator exhausts its reactive reserves, which is marked as a Q-limited (QL) bus, and it becomes a PQ type bus. The number of QL buses, characteristic for each contingency, determines the selection of SFA buses.

The selection for SFA buses includes all generators QL buses and a subset of buses with the highest PFs. The pseudo-code for this step is as follows:

> Set PF_threshold=PF_T
> <u>*For*</u> each contingency case *i*
> > Determine X*i*=number of generators at their limit in contingency case *i*
> > Select the buses with PFs >= PF_T
> > Denote the selected buses as set SFA*i*
> > Include the corresponding X*i* generator buses, if any, into SFA*i*
>
> <u>*End*</u>
>
> Note 1 A SFA*i* set consists of
> > a. buses with PFs >= PF_T, selected for analysis
> > b. Xi generator buses that have exhausted their reactive reserves
> >
> > The PF range of the buses selected for analysis is [PFmax, PFmin]; PFmax is always 1 since the list of buses includes the bus with the highest PF. PFmin, however, varies for each contingency cases.
>
> Note 2 Based on computational experience PF_T=0.7 is used.

2. Clustering of Contingency Cases based on SFAs.

As mentioned earlier, the identification program clusters contingency cases based on similarities of their corresponding SFAs sets. In this step only the buses having high PFs are used for comparison (generators that are at their reactive power limit are not considered at this stage).

Several contingency clusters **C***k* are constructed in this step. Later on, these clusters will be used to identify the VCAs in the power system (Steps 6 and 7).

The first step in a clustering process is the selection of a particular SFA*x* as the base for the cluster (heuristic rules for selecting the base are given in 4.2). Then every SFA*i* is compared against this base set. If predetermined percentage of SFA*i* buses are members of the SFA*x* set, then those sets are consider being similar and are grouped together.

After grouping the SFAs similar to SFA*x* base set a new base set SFA*z* is selected for the remaining SFAs. Then the process is repeated until all SFAs are grouped (groups of a single SFA are allowed). The pseudo-code for this step is as follows:

Set k=1 (counter for number of clusters **C***k*)
Repeat until all SFAs are grouped
  Create empty cluster **C***k*
  From SFAs not yet grouped select base set SFA*x*.
  Include SFA*x* in **C***k* (SFA*x* → **C***k*)
    - *For* every SFA*i* not yet grouped
     If buses in SFA*i* are similar to buses in SFA*x* then include SFA*i* in **C***k*
    - *End* for every SFAi not yet grouped
    If every SFA*i* has been grouped *then* STOP;
      otherwise increase k and repeat the procedure.
End

3. Normalization of Generator Buses PFs.

For every SFA*i* in cluster **C***k*, the generator buses PFs are normalized. If a given SFA*i* contains X*i* generator buses then the maximum PF value of those Xi buses is used as a normalization factor. Then, a subset of Y*i* generator buses with the highest normalized PFs is selected for further analysis (remaining generator buses are eliminated from SFA*i*). The pseudo-code for this step is as follows:

For each cluster **C***k*
  For each SFA*i* in **C***k*
    Normalized the PFs of the X*i* generator-buses
    Select the Y*i* generator buses with normalized PFs>=β
    In SFA*i* replace set Xi by set Yi
  End for each SFA*i* in **C***k*
End for each cluster **C***k*

Note The β factor is used to select only the most significant generator buses; β is a threshold for the generator buses normalized PFs below which the generator buses are excluded from SFAs. Based on computational experience β=0.6 is used.

4. Selection of Generators in Cluster C*k*.

For each cluster **C***k*, the frequency of generator bus participations in this **C***k* is calculated as the number of SFAs in which a given generator bus is present. The generator buses with the highest frequencies are selected to represent the cluster **C***k* reactive reserves and are denoted as **GEN***k*. The pseudo-code for this step is as follows

For each cluster **C***k*

For each generator-bus-*z* in **C***k*

Compute frequency F*z* for generator bus z

F*z*=number of SFAs where generator bus *z* is present

End for each generator bus *z*

Select the set of generator buses with Fz >= δ

Denote this set of generator bus set as **GEN***k*

Remove generator buses from each **SFA***i* in cluster **C***k*

End for each cluster **C***k*

Note The factor δ is a frequency threshold used for the selection of generator buses. The higher the frequency of a generator bus, the higher the possibility of selecting the generator bus. The value for δ depends on the number of SFAs in a given **C***k*. Based on computational experience δ is set to be equal to 0.4 times the number of SFAs in **C***k*. That means that a generator bus is selected to be in **GEN***k* only if it appears in at least 40% of all the SFAs of the corresponding **C***k*.

5. Clustering of C*k* based on GENs.

In this step, **C***k* are grouped together if their corresponding GEN sets are similar. Two GENs are considered similar if certain percentage of generator buses are matched. If **GEN***i* (from **C***i*) and **GEN***j* (from **C***j*) are similar, then **C***i* and **C***j* are grouped together into a preliminary VCA, say **VCA*m***. This **VCA***m* is associated with a set of generator buses **GEN***m* that consists of the generator buses of the combined **GEN***i* and **GEN***j*.

The first step in clustering **C***k* is to select the base set **GEN***x* (heuristic rules for selecting the base set are given in 4.2) to which other **GEN**s are compared. All **C***k*, which have GEN sets similar to **GEN***x* are clustered. Then a new base **GEN***y* is selected from the remaining ungrouped **C***k* and the process of clustering is repeated for the ungrouped **C***k*.

The following example illustrates this clustering process.

Let's assume that based on pattern recognition we have determined that **GEN***i*, **GEN***a* and **GEN***b* are similar and thus they should be clustered together. Let's also assume that the generator buses, and their frequencies in **GEN***i*, **GEN***a* and **GEN***b* are those given in Table-1.

Then:

- a preliminary **VCA*m*** is formed all SFAs of **C***i*, **C***a*, and **C***b* are combined together
  C*i*= {SFAa, SFAb, SFAc}
  C*a*= {SFAd, SFAg}
  C*b*= {SFAz}
  →VCAm = {**C***i*, **C***a*, **C***b* }={SFAa, SFAb, SFAc, SFAd, SFAg, SFAz}
- a set **GEN***m* associated with **VCA***m* is formed **GEN***m* consists of all the generator buses from **GEN***i*, **GEN***a* and **GEN***b* and their frequencies are the total numbers of participations in all SFAs combined together in **VCA***m* (as shown in below table).

Table 4-1: Example of Clustering based on the Generators Frequencies

Sets	Generator buses and frequencies					
	X	Y	Z	W	V	H

GEN*i*	10	20	15	---	10	---
GEN*a*	20	12	---	18	10	
GEN*b*	5	---	4	---	7	3
GEN*m*	35	32	19	18	27	3

The pseudo code for this step is as follows:

Set m=1 (counter for number of preliminary VCAs)
Repeat until all clusters **C***k* have been grouped
    Create empty preliminary **VCA***m*
    Create empty **GEN***m*
    From **C***k* not yet grouped select base set **GEN***x*.
    Include all SFAs, from corresponding **C***x*, into the **VCA***m*
        SFA(**C***x*) $\rightarrow$ **VCA***m*
        Update **GEN***m* = **GEN***x* $\cap$ **GEN***m*
    For each **C***i* not yet grouped
      If corresponding **GEN***i* is similar to **GEN***x* *then*
        SFA(**C***i*) $\rightarrow$ **VCA***m*
        Update **GEN***m* = **GEN***i* $\cap$ **GEN***m*
    End for each **C***i* not yet grouped
    If all **C***k* have been grouped *then* STOP;
        otherwise increase m and repeat the procedure.
End

After this step, a set of preliminary **VCAs** is established. Each preliminary **VCA***m* relates to a unique set of generator buses **GEN***m*.

6. VCA identification part A Selection of buses.

For each preliminary **VCA***m*, compute the frequency of each bus. Then select the buses with a frequency greater than 50% the number of SFAs in that **VCA***m*. These are the buses that form **VCA***m* of the given power system.

7. VCA identification part B Selection of generators.

For each **GEN***m*, get the frequency of each generator bus. Then select the generator buses with a frequency greater than 50% the number of SFAs in the corresponding **VCA***m*. The generators associated with these generator buses are the ones that form controlling generators associated with **VCA***m* of the given power system.

Heuristic Rules for Base Selection and Similarity Measurement

(a) Selection of a base for clustering process

From the VCA identification process presented in section 5.1 we can observe that clustering is carried out twice

- Clustering contingency cases based on SFAs (Step 2) and

- Clustering **C***k* based on GENs (Step 5)

Each clustering process starts with the selection of a base set for the cluster. Then any other set is compared to this base to evaluate whether they are similar. Both clustering processes are shown in the diagram of the VCA identification program in Figure 4-3, Data Flow Diagram for VCA Identification Program.

In Step 2, two different criteria for the selection of a base SFA*x* set were tested

1. Largest contingency (SFA). After the SFAs are found in Step 1, the number of buses in each SFA is counted. The SFA with the highest number of buses is selected as the SFA*x* base for a cluster and then similar SFAs are grouped together.

2. Most severe contingency (SFA). As part of the voltage stability assessment of the system, we also compute the margin for each contingency case. The SFA corresponding to the contingency with the smallest margin is selected as the base of the cluster. Then similar SFAs are grouped together.

Criterion 2 was found more suitable and therefore it is applied in the VCA identification program.

For clustering in Step 5, the GEN set with the highest number of generator-buses is selected as the base GEN*x* of a cluster. Then similar GENs are grouped together.

(b) Measure of similarity between sets

Whether we are dealing with SFAs or GENs the measure of similarity is the same. First the numbers of buses in the base sets SFA*x* or GEN*x* as well as the SFAs or GENs sets for all cases are counted. Then the elements of set-i (either SFA*i* or GEN*i*) are compared with the elements of the base set (either SFA*x* or GEN*x*). The number of common elements C is counted and compared with the similarity threshold T. If the number of common elements C is greater than the threshold T, then set-i and the base set are considered being similar. The similarity threshold T is set as a percentage of the number of elements of in the largest set (set-i or the base set).

If all elements of the smaller set (base or set-*i*) are included in the larger set then those sets are considered being similar.

The pseudo code for checking sets similarities is as follows:

Compute B=number of elements in base	
Compute R=number of elements in set-*i*	
Compute maximum number of elements	M=max(B,R)
Compute threshold for common elements	T=ΦM
Compute number of common elements between base and set-*i*	C=common elements
If C>=T *then* base and set-*i* are similar	
If C<T *then*	

Denote the set (base or set-*i*) with the lowest number of elements by S. *If* all elements in this smallest set are included in the largest set *then* sets are similar; *otherwise* sets are not similar.

Note The factor represents a similarity threshold. This similarity threshold is used to compute the threshold for common elements (T). The value of T depends not only of but also in the number of elements in the largest set. If the number of common elements C is equal to or greater than T, then the two sets being compared are considered to be similar.

Based on computational experience = 0.50 is used. That means that two sets are similar only if the number of common elements is equal to or greater than 50% the number of elements of the largest set.

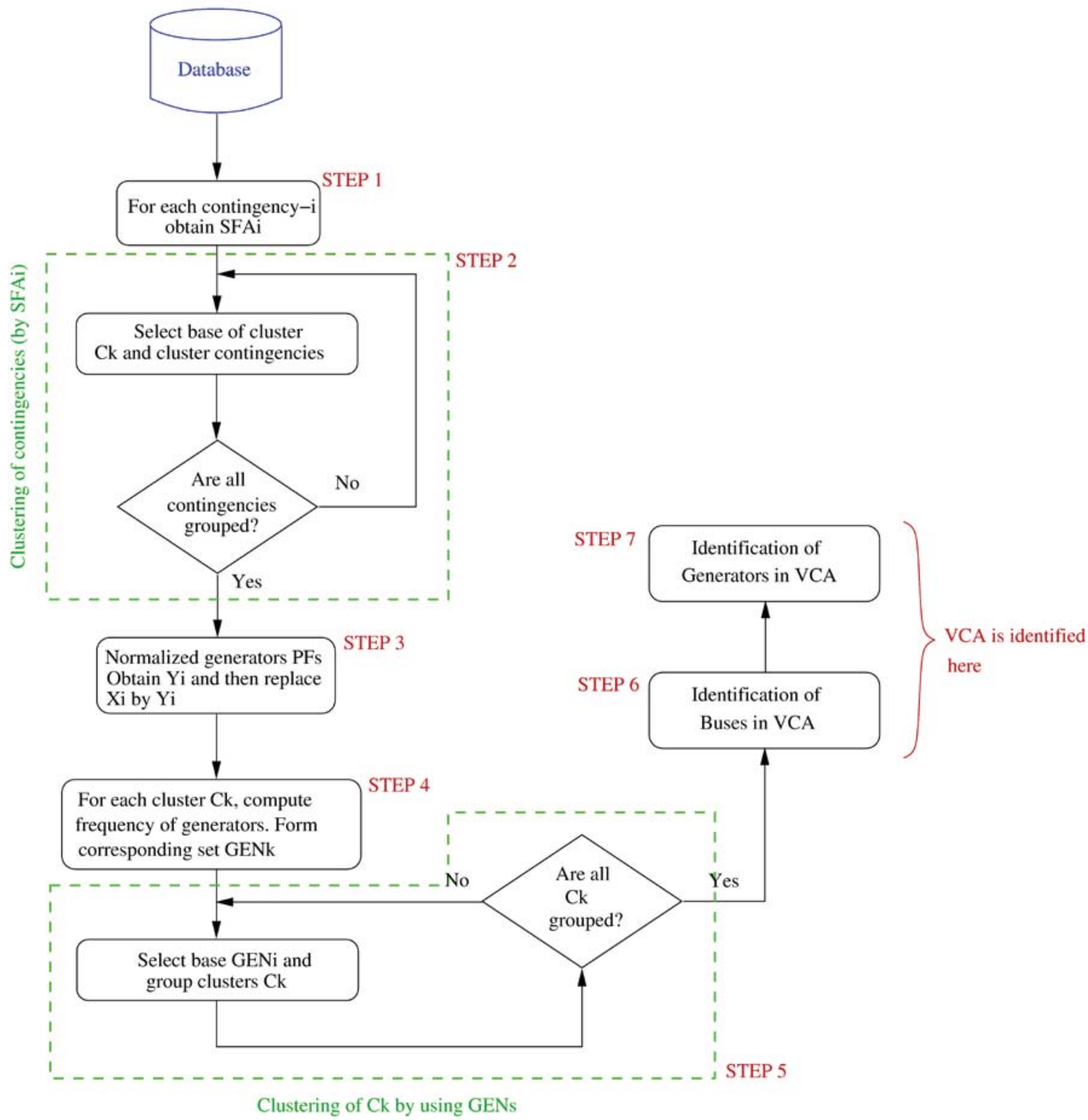


Figure 4-3 Data Flow Diagram for VCA Identification Program

Analysis of VCA Identification Process

Analysis of VCA Buses

It is understood that VCA buses are those prone to voltage stability problems. PFs could be used to identify these buses. Still, as mentioned earlier, PFs are normalized with respect to the maximum PF value of each mode for each contingency, thus they cannot be compared. A per-contingency linear ranking metric, however, can measure how important a bus is independently of how much its PF varies across contingency cases. It is expected that VCA buses have a higher ranking (more important) than those of non-VCA buses. An example of how to rank buses, based on their PFs, is given below.

Let's assume that the total number of buses in the system equals four (n=4). Let's also assume that two contingency cases are considered and that their PFs are those given by

Bus PFs

CntgA=[B1	B2	B3	B4]	=[1.0	0.8	0.7	0]
CntgB=[B1	B2	B3	B4]	=[0.4	1.0	0	0]

To rank the buses listed above one proceeds as follows. For a given contingency, the bus with the highest PF is mapped/ranked into n=4. Then the bus with the second highest value is mapped into (n-1), then the next one into (n-2) and so on. Buses with PFs=0 are mapped into 1 (minimum ranking value). That is, the buses listed above are ranked as follows.

Bus Ranking

CntgA=[B1	B2	B3	B4]	=[4	3	2	1]
CntgB=[B1	B2	B3	B4]	=[3	4	1	1]

Then, ranking values are normalized with respect to n; that is,

Normalized Ranking

CntgA=[B1	B2	B3	B4]	=[1	0.75	0.5	0.25]
CntgB=[B1	B2	B3	B4]	=[0.75	1	0.25	0.25]

The normalized ranking values are not the same as the PFs. For instance, the bus with the second highest PF is always ranked to the same normalized ranking value (0.75 in the example given); i.e., this ranking is independent of how different the PFs of these buses are for the different contingencies. These normalized ranking values are used to evaluate the identified VCA buses. Figure 4-4 and Figure 4-5 show the ranking values for a set of VCA buses and for a set of related contingencies. Specifically, Figure 4-4 shows the ranking values of a set of 30 buses across 50 contingency cases; these buses and contingencies are related to VCA-1.

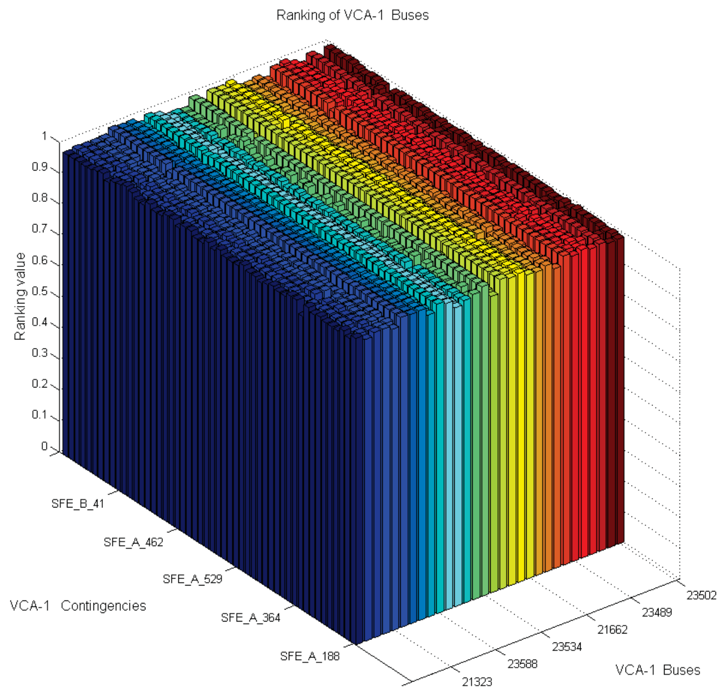


Figure 4-4 Ranking values VCA-1 Buses (30 Buses and 50 contingency cases)

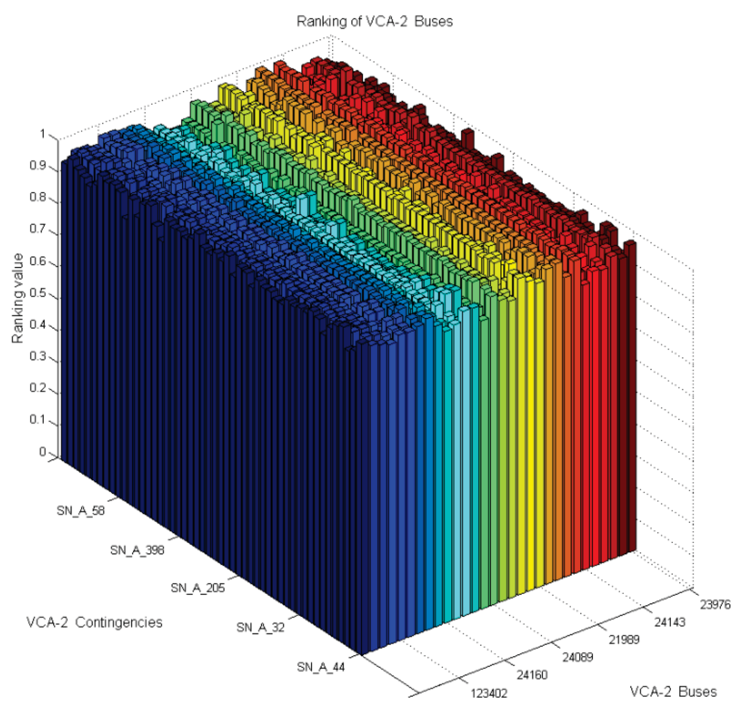


Figure 4-5 Ranking values VCA-2 Buses (30 Buses and 50 contingency cases)

On the other hand, Figure 4-6 shows the ranking values of a set of non-VCA buses. Comparing Figure 4-4 and Figure 4-5 versus Figure 4-6, one can observe that the ranking values of the VCA buses are higher than those of the non-VCA buses. That is, the identified VCA buses are indeed the most important buses prone to voltage instability problems.

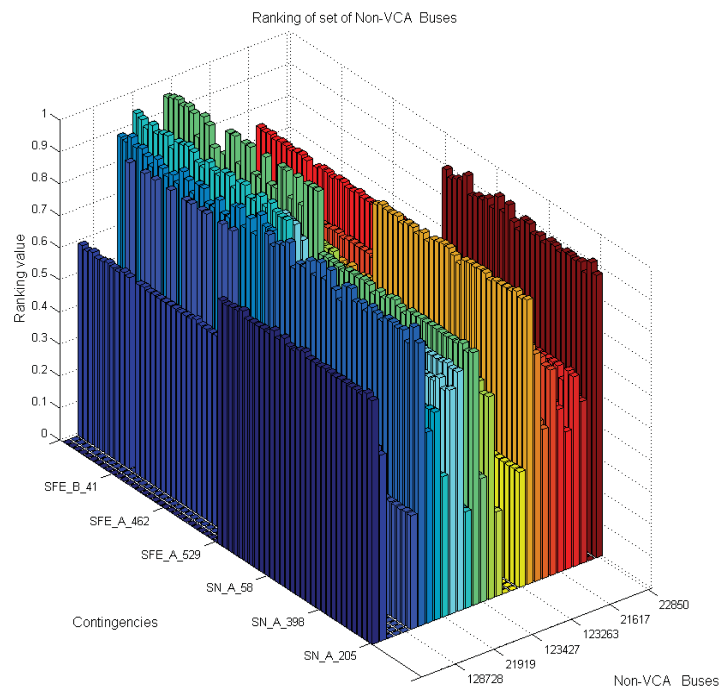


Figure 4-6 Ranking of Non-VCA Buses (30 Buses and 60 contingency cases)

Analysis of VCA Generators

“VCA generators” are those generators that initiate the instability of the VCA once their reactive power reserves have been exhausted. That is, VCA generators are the location where reactive power reserves should be kept so that voltage instability is avoided.

In the previous section, buses are ranked in order to identify how important they are. Such an approach is not suitable for the generators since we are not interested on how important (rank) they are, but rather how effective they are in preventing voltage instability. For a single contingency case, for instance, a generator that is ranked in second place might not be as effective in avoiding voltage instability as the generator ranked in the first place. In other words, reactive power reserves in the generator ranked second will not produce the same system improvement as if these reserves were allocated to the generator ranked first instead. A per-contingency generator-PF-normalization metric can measure how effective generators are. It is expected that VCA generators have higher normalized PFs than those of non-VCA generators. An example of how to normalized generators PFs follows.

Consider the following contingencies cases and generators PFs:

PFs of QL generators (generators that are at their reactive power limit)

CntgA=[G1 G2 G3 G4] = [0.4 0.2 0.1 0] (max=0.4)
CntgB=[G1 G2 G3 G4] = [0.1 0.2 0.1 0.3] (max=0.3)

Then, one normalizes the PFs with respect the highest PF of the corresponding contingency; that is,

Normalized PFs of QL generators

CntgA=[G1	G2	G3	G4]	=[1	0.5	0.25	0]
CntgB=[G1	G2	G3	G4]	=[0.3	0.6	0.3	1]

Figure 4-7 and Figure 4-8 show the normalized PFs of the VCA-1 and VCA-2 generators; these values are higher than those of the non-VCA generators (shown in Figure 4-9). That is, the set of identified VCA generators are the most effective to avoid voltage instability if reactive reserves are kept in.

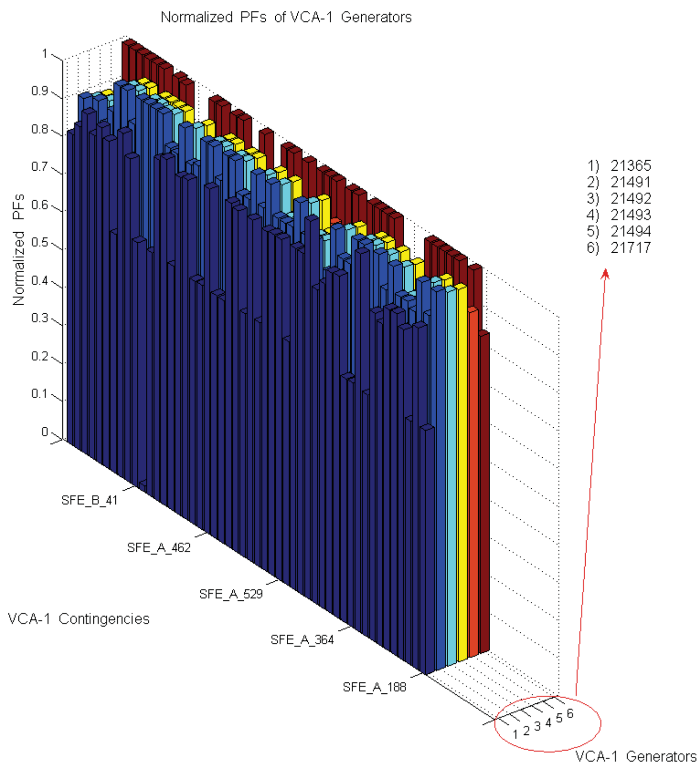


Figure 4-7 Normalized PFs of VCA-1 Generators (6 Generators and 50 contingency cases)

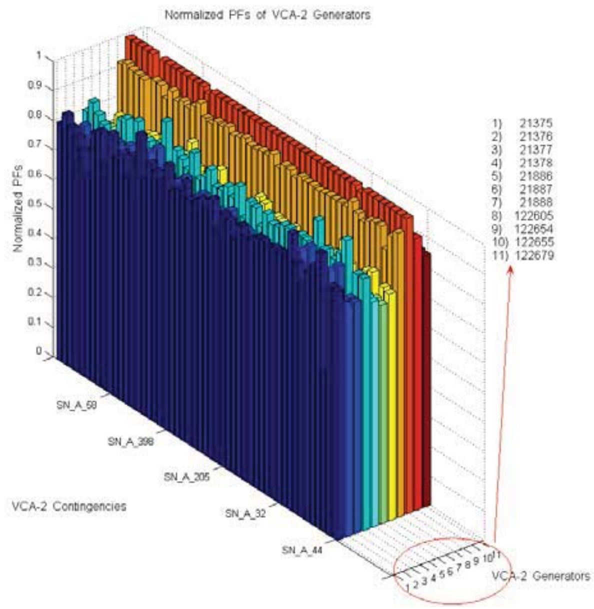


Figure 4-8 Normalized PFs of VCA-2 Generators (11 Generators and 50 contingency cases)

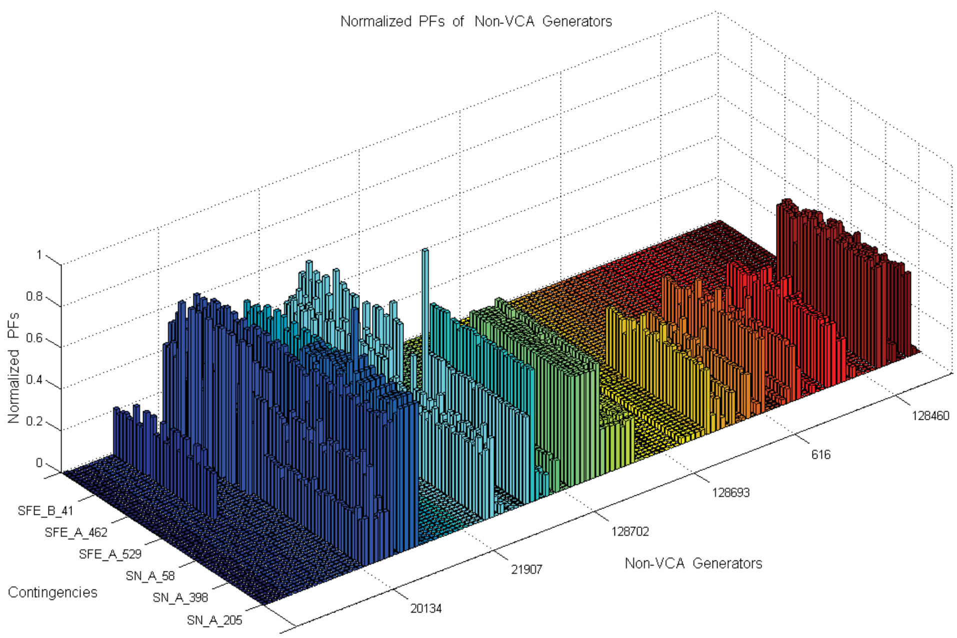


Figure 4-9 Normalized PFs of Non-VCA Generators (131 Generators and 60 contingencies)

Performance of VCA-1 Generators when reactive power reserves are increased

In order to evaluate the effectiveness of the identified VCA generators, for VCA-1, the following test was carried out. An additional 50 MVAR reserve was uniformly distributed on the set of the VCA-1 generators. Then the points of voltage instability of the associated contingencies were computed. These voltage instability points were compared against those when there is no increase in reserves. The objective of this test is to measure how the power transfer increases, for the various contingencies considered, when the reactive reserves in this set of VCA-1 generators is increased.

The above increment in power transfer was compared against that obtained when a 50 MVAR reserve is distributed on each of two other sets of generators. Based on experience, these two other sets of generators were identified as the most promising for a high power transfer increment. Figure 4-10 shows the MW-Transfer increase obtained when an additional 50 MVAR reactive power reserve is distributed on various sets of generators. The mean MW transfer increase (M-MW-Inc) is higher for the set of VCA-1 generators than that for the other two sets. That is, the identified VCA-1 generators are the most effective in securing voltage stability since the points of voltage instability, for the various associated contingencies, occurs farther ahead than that at the other two sets of generators tested.

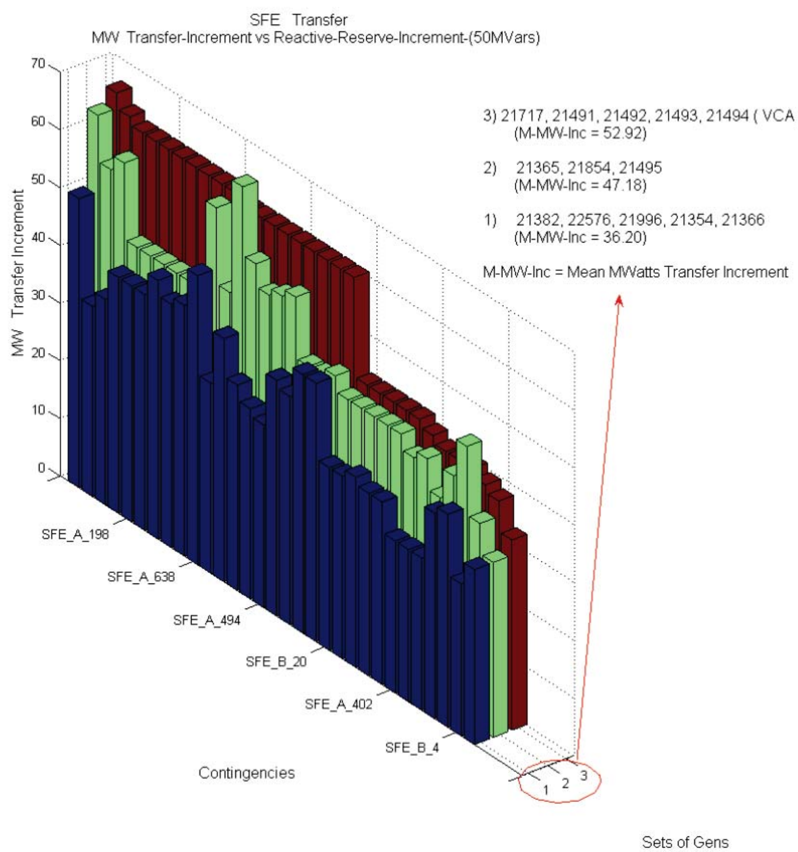


Figure 4-10 Transfer Increase Comparison Set of VCA-Generators Versus Other Sets.

Section 5: Reactive Power Reserve Requirement and Allocation Method

Reactive reserves must be established for the pre-contingency (see the red curve shown in the below figure) condition, therefore, the pre-contingency conditions corresponding to the post contingency (e.g. the blue curve in Figure 5-1) nose point of the PV curve should be tracked during system stressing. The required reactive reserves can then be established as shown in Figure 5-1 below. The stability limit is found as Point A (if the contingency shown happens while the system is at point A, the system will be at the point of instability) and a margin is applied such that the operating limit is at Point B (5% of the transfer, for example). The reactive power reserve required for a VCA corresponding to this contingency is given by the reserve that exist at point B. All contingencies that are related to the same VCA must be examined and the greatest of all reserves should be taken as the reserve requirement. It is also important to note that the proper share of reserve requirement for each of the reactive reserve resources (generators, SVC, etc.) within one VCA should also be established to assure that stability under different unit commitments and generation scheduling.

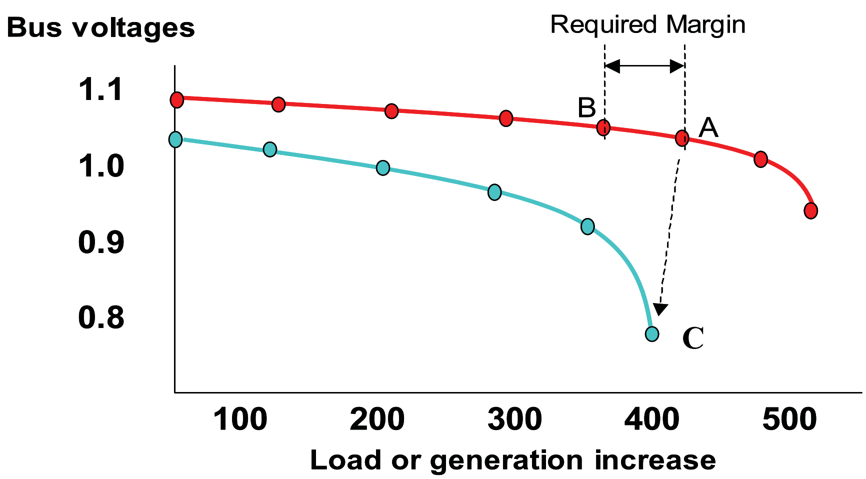


Figure 5-1 Determining Reactive Reserve Requirements

The following approach was devised to determine the required reactive reserve among the units that are controlling a VCA.

1. For a given base case, transfer definitions and contingencies, follow the process to identify VCAs and their corresponding controlling generators (RRG) as described in the previous chapter.

2. For each VCA, record the post-contingency VAr output of all RRG units at the stability limit (point C in Figure 5-1).

3. For each VCA, at pre-contingency point (point B in the figure) record the VAr output of all RRG units. This operating point has the required margin (say 5%)

4. The required reactive reserve of unit *j, denoted by* R_j, for this case/transfer/contingency, is the difference between its recorded VAr output at point C, Q_j^C, and point B, Q_j^B

$$R_j = Q_j^C \quad Q_j^B \text{ ....5-1}$$

If a unit becomes out-of-service due to a contingency at point C, then its reserve requirement is zero (the lost VAr of this unit is reflected in the output of other units and their R_j)

$$R_j = 0 \text{ ....5-2}$$

Since RRG units are the critical units that are at their VAr limit at point C, R_j is simply the reactive reserve left at point B

$$R_j = Q_{j\max} \quad Q_j^B \text{ ....5-3}$$

5. Reactive reserve of RRG units for all transfers and all contingencies that have resulted in the corresponding VCA can be stored in the following table

Table 5-1 Example of recorded reactive reserves of RRG units

Transfer/Contingency	Unit 1	Unit 2	Unit 3	Unit 4	Unit 5
Trf A / Ctg 1	20	20	10	10	10
Trf B / Ctg 1	18	18	12	12	12
Trf B / Ctg 3	30	0	15	15	15
Trf C / Ctg 4	25	25	12	12	0

In the above example, it is assumed that the corresponding VCA has been identified for transfer A under contingency 1, transfer B under contingency 1 and 3, and transfer C under contingency 4. Its RRG is assumed to have 5 units. Numbers in the table, r_{ij}, are examples of recorded reserves of the units. Contingency 3 had caused the outage of unit 2 and contingency 4 had caused the outage of unit 5 of this RRG.

If sensitivity of the stability margin of transfer/contingency i to the reactive reserve (or reactive output) of unit j can be approximated by s_{ij}, and if it can be assumed that the sensitivity factors remain valid for the range of reactive reserve variations in the above table (range of r_{ij}), then for each row i of the above table, we can write

$$\sum_{j=1:n} s_{ij}\left(R_j \; r_{ij}\right) \geq 0 \text{ ,} i=1 \; M \text{ ....5-4}$$

or

$$\sum_{j=1:n} s_{ij} R_j \geq Q_i \text{, } i=1 \; M \text{ ....5-5}$$

where

$$Q_i = \sum_{j=1:n} s_{ij} r_{ij} \text{ , } i=1 \; M \text{ ....5-6}$$

R_j is the required reactive reserve for unit j (unknown), s_{ij} is its sensitivity and r_{ij} is its recorded reserve for transfer/contingency i. M is the number of transfers/contingencies associated with this RRG and n is the number of units in the RRG.

Table 5-2 Example of recorded sensitivities of RRG units

Transfer/Contingency	Unit 1	Unit 2	Unit 3	Unit 4	Unit 5
Trf A / Ctg 1	1.04	0.79	1.29	1.28	1.28
Trf B / Ctg 1	0.14	0.01	1.03	1.02	1.02
Trf B / Ctg 3	0.93	0.75	0.97	0.97	0.96
Trf C / Ctg 4	0.87	0.73	0.87	0.86	0.86

Numbers in the table, s_{ij}, are examples of recorded sensitivities of VCA units.

6. To find a single answer for the reserve requirements of the simulated cases (i.e., merge the rows of the above table), or predict the reserve requirements of a new case which is similar to these simulated cases, we can solve the following linear programming (LP) problem:

$$\min \sum_{j=1:n} k_j R_j \quad \text{...} 5\text{-}6$$

subject to:

$$\sum_{j=1:n} s_{ij} k_j R_j \quad Q_i, \qquad i = 1:M \quad \text{..} 5\text{-}7$$

$$R_j \quad k_j r_{\min j} \quad \text{...} 5\text{-}8$$

$$\mathbf{0} \le R_j \le Q_{\max j} \quad Q_{\min j} \quad \text{..} 5\text{-}9$$

Where,

$$r_{\min j} = \min(r_{ij}), \qquad i = 1:M$$

and $Q_{\max j}$ and $Q_{\min j}$ are the maximum and minimum VAr limits of unit j in the case for which R_j is being computed, and k_j is

$$k_j = 1 \text{ (unit on-line)}$$

$$k_j = 0 \text{ (unit off-line)} \quad \text{...........................} 5\text{-}10$$

The inequality constraint appearing in **Eq. 5-7** is to meet the requirements of computed (recorded) cases. Constraint appearing in **Eq. 5-9** is to keep reactive reserves within the range of computed (recorded) values. Also, without **Eq. 5-8**, the LP will be ill-defined if there are few rows in **Eq. 5-7** with different sensitivities. For example, if there is only one constraint in **Eq. 5-7** and three units with the same sensitivity, there is no solution, and if the sensitivities are different, the minimum solution will be zero for less-sensitive units. With **Eq. 5-8**, even for these cases, the solution will be equal or close to the recorded values. Constraint appearing in **Eq. 5-9** means that the maximum reserve that each unit may have is when it is at its minimum VAr output. Maximum and minimum VAr limits are not fixed, for example the unit might have been de-rated, and so these must be specified for a new case for which we are computing the required reserves. If constraint in **Eq. 5-9** becomes infeasible ($r_{\min j} \quad Q_{\max j} \quad Q_{\min j}$) then we can relax it by setting $r_{\min j} = Q_{\max j} \quad Q_{\min j}$.

If the LP becomes infeasible (in case of $k_j = 0$ or reduced $Q_{\max j}$) then we report the "nearest" solution which is $R_j = Q_{\max j} \quad Q_{\min j}$ for all units (i.e., units must be at the minimum output or maximum reserve) and the VAr shortage which is the largest of $Q_i \quad \sum_{j=1:n} s_{ij} k_j R_j$ for *i=1 M.*

The details of the generators reactive power sensitivity factors with respect to stability margin is presented in the following section.

Sensitivity of Stability Margin w.r.t Generator Reactive Power

To allocate the required amount of reactive power reserve, in each scenario, between the VCA controlling generators we need to know which generators have the greatest influence on the stability. This can be achieved by using the results of modal analysis as described below.

The sensitivity factors are derived from the first order sensitivity of the loading margins λ with respect to generator reactive power outputs Q_g. Suppose that the equilibriums of power system satisfy the equation:

$$f(x,\lambda,Q_g) = 0 \quad \ldots\ldots 5\text{-}11$$

Where x is the vector of state variables

λ is the loading margins measured with sink loads

Q_g is the generator reactive power outputs.

At a saddle node bifurcation, the Jacobian matrix is singular. For each (x,λ,Q_g) corresponding to a bifurcation, there is a left eigenvector $w(x,\lambda,Q_g)$ corresponding to the zero eigenvalue of f_x such that:

$$w(x,\lambda,Q_g) \quad f_x(x,\lambda,Q_g) = 0 \quad \ldots\ldots 5\text{-}12$$

The Taylor series expansion of Equation 5-12 yields:

$$f_x \Delta x + f_\lambda \Delta\lambda + f_{Qg} \Delta Q_g = 0 \quad \ldots\ldots 5\text{-}13$$

Pre-multiplication by $w(x,\lambda,Q_g)$

$$w \;\; f_{\lambda}\Delta\lambda + w \;\; f_{Qg}\Delta Q_{g} = 0 \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots 5\text{-}14$$

Hence the sensitivity of the stability margin to the change in generator reactive power is

$$s_{g} = \frac{\Delta\lambda}{\Delta Q_{g}} = \frac{w \;\; f_{Qg}}{w \;\; f_{\lambda}} \qquad \frac{w \;\; f_{Qg}}{w \;\; (f_{\lambda \sin k}{}^{T}, f_{\lambda source}{}^{T})^{T}} \ldots\ldots\ldots\ldots\ldots 5\text{-}15$$

Where

$f_{\lambda \sin k}$ is the unit vector representing the direction of the sink changes and,

$f_{\lambda source}$ is the unit vector representing the direction of the source changes.

The above mathematical derivations of the sensitivity factor was coded and tested. The result obtained proved correct when compared with reactive power increase and re-computing stability margin using VSAT program.

Section 6: New York Transmission System – Study Scenarios

New York Transmission System

The New York Independent System Operator (NYISO) manages New York's electricity transmission grid and facilitates the wholesale electric markets in order to ensure overall system reliability. The New York bulk electric transmission system is neighbored by four control areas juxtaposing US and Canadian territories. These areas include ISO-NE (Independent System Operator – New England), PJM (Pennsylvania – Jersey - Maryland), HQ (Hydro-Québec), and IESO (Independent System Operator of Ontario). In addition to using 115 kV and 138 kV transmission systems, the NYISO network includes 230 kV, 345 kV and 765 kV lines.

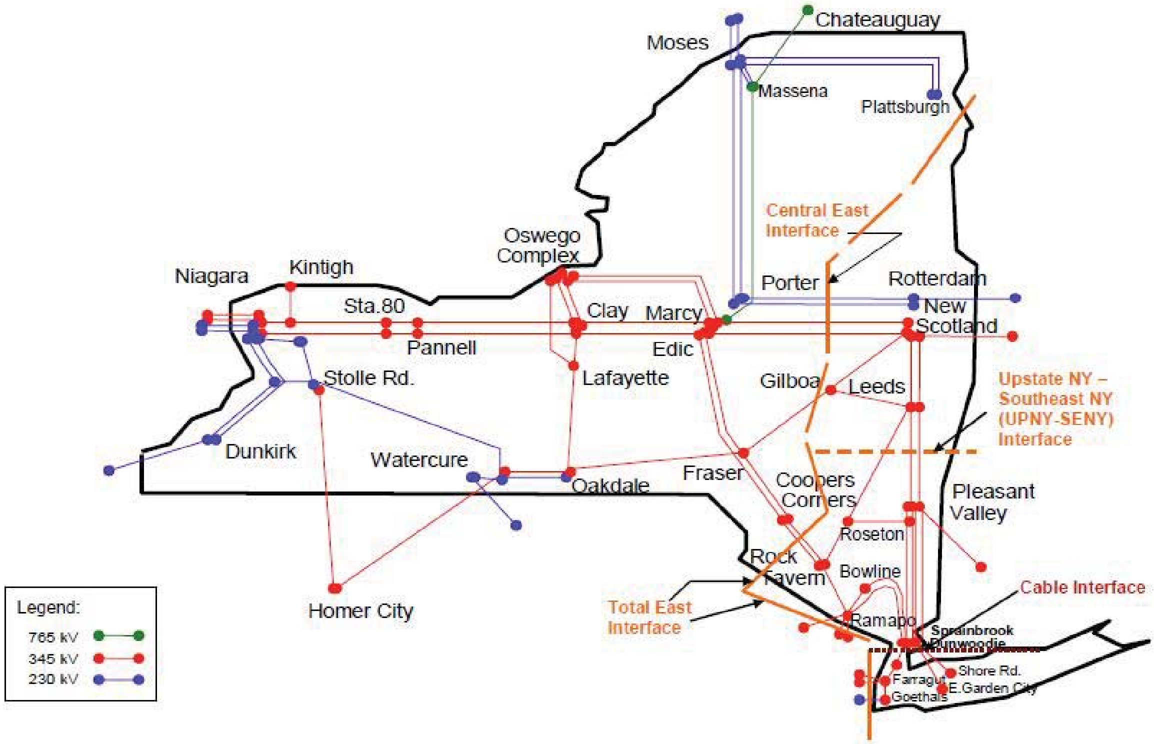


Figure 6-1 NYISO transmission map (230 kV and above) (Ref. 18)

The NYISO system exhibits summer peaking characteristics and the 2009 summer coincident peak load was forecast at 33.5 GW (Ref. 19). The New York City metropolitan area (NYC) and Long Island (LI) are areas of concentrated demand. Both localities have requirements for installed generating capacity that are more stringent than the rest of the region, to ensure reliability of service. Among the 11 zones typically used in analyzing this system, these load pockets are located in Zone J (New York City) and Zone K (Long Island). These 'Zones' (Figure 6-2), however, are expressed as 'Areas' in the base case powerflows.

Figure 6-2 New York (NYISO) Electric Regions (Ref.20)

For the purposes of transfer limit analysis, the NYISO system is typically studied under a number of cross-state interfaces. Similar transfer capabilities are also established between inter-state balancing areas (Ref.21, Figure 6-3).

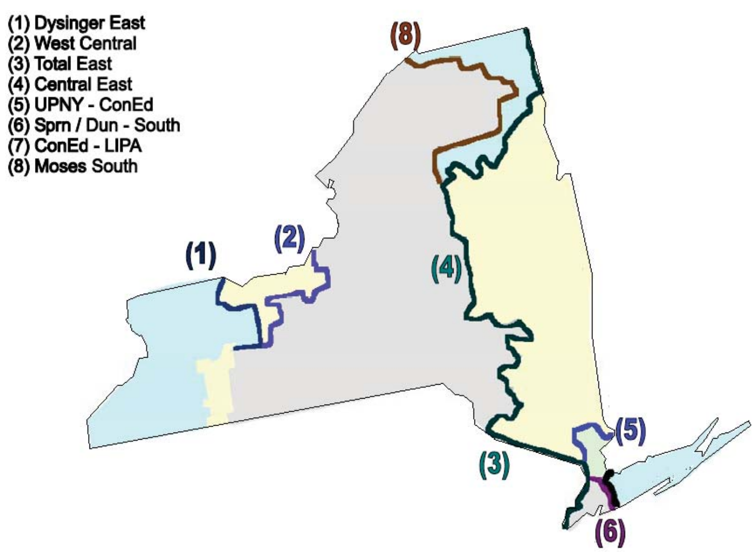


Figure 6-3 Cross-state transfer for thermal capability assessment

For this VCA study, a set of powerflow basecases, transfers, contingencies and general information has been supplied by the NYISO. This information (including the file format and the contents) are listed in Table 6-1.

Table 6-1: Data files received for the VCA study

Files received to date	***Contents***	***Short names***	***Numbers***
Basecases			**3**
ceiiferc07-ll12.raw	Light Load basecase	LL	
ceiiferc07-win12.raw	Winter Peaking basecase	WIN	
ceiiferc07-sum12.raw	Summer Peaking basecase	SUM	
CY07-ATBA-SUM12_rev4.raw	(Not used to date)		
Transfers			**4**
DB2007_ds.sub	Dunwoodie South	DS	
DB2007_dyse.sub	Dysinger East	DYSE	
DB2007_te.sub	Total East	TE	
DB2007_uc.sub	Upstate NY Con	UC	
Contingencies			**~ 1300**
DB2007_COMMON_rev1.con	Common contingencies	COM	525
DB2007_NY-rev1.con	N-1 contingencies	N1	520(DS) 850(DYSE), 729(UC) 508(TE)
LIPA_NYSERDA_Contingency_List.con	LIPA- NYSERDA contingencies	LIPA	149
Reactors, Capacitors & SVC/StatCom			**-**
Con Ed Reactors and Caps.xls	Switchable caps	-	-
Shunt Reactor rev 2 ConEd.xls	Shunt reactors	-	-
SO03-34-0.doc	Series reactors	-	-
SVC Control Strategies.doc	SVCs and StatComs	-	-

Once the powerflow basecases were checked for convergence and data sanity, modifications were made to set the reactors, capacitors and SVC/StatCom devices accordingly. These changes are listed in Section A-1:

Powerflow Basecases

The powerflow basecases supplied for this study are from 2007 series ERAG/MMWG data sets and correspond to 2012 summer peak, winter peak, and light load conditions. Additional information on settings for series/shunt reactors, switchable capacitors and SVC/StatCom devices was also provided.

Table 6-2: Powerflow data summary

```
CEII 2007 FERC FORM NO. 715, PART2 BASE CASE
2012 SUMMER PEAK LOAD, LEVEL 5 (04/01/07)

Summary:
 51960  AC Buses                             70  DC Buses
  7762  Generators                           70  Converters
 29069  Loads                                0   Voltage Source Converters
  3474  Fixed Shunts                         35  DC Lines
  4671  Switchable Shunts                    0   DC Breakers
 48282  Lines                                147 Areas
     0  Fixed Transformers                   463 Zones
 18606  Adjustable Transformers              11  Owners
   837  Three Winding Transformers           33  Sectional Branches
     0  Fixed Series Compensators
     0  Fixed Series Compensators
     0  Adjustable Series Compensators
     0  Static Tap Changer/Phase Regulator
```

```
CEII 2007 FERC FORM NO. 715, PART2 BASE CASE
2012-13 WINTER LOAD, LEVEL 5 (04/01/2007)

Summary:
 50260  AC Buses                           70  DC Buses
  7583  Generators                         70  Converters
 28576  Loads                              0   Voltage Source Converters
  3359  Fixed Shunts                       35  DC Lines
  4648  Switchable Shunts                  0   DC Breakers
 46943  Lines                              147 Areas
     0  Fixed Transformers                 483 Zones
 17866  Adjustable Transformers            11  Owners
   950  Three Winding Transformers         33  Sectional Branches
     0  Fixed Series Compensators
     0  Fixed Series Compensators
     0  Adjustable Series Compensators
     0  Static Tap Changer/Phase Regulator
```

```
CEII 2007 FERC FORM NO. 715, PART2 BASE CASE
2012 LIGHT LOAD, LEVEL 5 (04/01/2007)

Summary:

 49321  AC Buses                           66  DC Buses
  7471  Generators                         66  Converters
 27982  Loads                              0   Voltage Source Converters
  2716  Fixed Shunts                       33  DC Lines
  4553  Switchable Shunts                  0   DC Breakers
 46042  Lines                              146 Areas
     0  Fixed Transformers                 480 Zones
 17381  Adjustable Transformers            11  Owners
   931  Three Winding Transformers         33  Sectional Branches
     0  Fixed Series Compensators
     0  Fixed Series Compensators
     0  Adjustable Series Compensators
     0  Static Tap Changer/Phase Regulator
```

For the purposes of this study, the detail in which the system is modeled is of paramount importance. The representation of the system should be adequate enough for voltage stability study and voltage critical area identification. In other words, the powerflow basecases need to be robust and accurate to ensure realistic power transfer, contingency analysis as well as determination of voltage collapse areas of significance (as against localized weak areas). In an ideal case, this implies use of powerflow basecases with:

- fast convergence and numerical-stability
- representation for only the areas of interest including some buffer zones (i.e., reduced system)

- transmission and sub-transmission level models devoid of details of the distribution networks
- accurate line impedance, transformer impedance and HVDC control settings
- appropriate shunt control settings, especially near the possible areas of collapse

At the onset of the study, it was identified that there existed basecase problems with almost all the areas indicated above. In addition, the VCA application program was being in its BETA testing phase required special attention in conducting the study.

Subsequently, the following broad issues (primarily related to the powerflow basecases) have been identified:

- Detailed representation of the network (large system with both distribution and transmission level models)
- High sensitivity of the study case to the powerflow data (apparent subtle/minor changes may cause the basecases to diverge)
- Lengthy run-times required to identify and resolve inaccuracies/inconsistencies (each minute change requires a full analysis taking >48 hours to complete)

In addition, the following specific challenges were also identified:

- Convergence problems associated with dc systems (low line resistance, rectifier / inverter control settings , Limits on Alpha/Gamma too tight)
- Switchable shunts with narrow operating ranges (which causes powerflow convergence problems)
- Presence of many high-impedance distribution feeders supplying lightly loaded areas (which were being incorrectly identified as critical areas)
- Remote areas (such as, IESO, TVA, NB, etc.) incorrectly participating in voltage collapses within the NYC areas
- General inconsistencies associated with SVC/Statcom and Shunt/Reactor setting

Corrective steps undertaken includes but not limited to:

- All the changes were made in the powerflow basecases (especially in the SUMMER case). The transfers and contingencies were used verbatim, after conversion to DSAtools native formats.
- In order to attain accurate results and to ensure stable convergence, minimal changes were made.
- Changes within the NY areas (area 1-11) primarily includes load/line outage (1~5 MW/MVAr) in MOHAWK, GENESEE, CENTRAL, and CAPITAL areas. These changes were made selectively and judiciously.
- Changes outside NY areas include generator reactive capacity increase in TVA, load/line outage in IESO, WEC, JCPL areas, and various adjustments with switchable shunts/ULTCs. These changes were made so as to eliminate inaccuracies in PV/modal analysis exercises.

The details of these changes are listed in Appendix Section A-2:

Transfer Scenarios

A total of four cross-state transfer scenarios have been identified for this VCA study. These transfers correspond to the following interfaces (i) Dysinger – East (ii) Total –East (iii) Upstate New York – ConEd, and (iv) Dunwoodie – South. The source and sink subsystems are characterized by increase and decrease of generation, respectively (no load increase is considered in the sink subsystem).

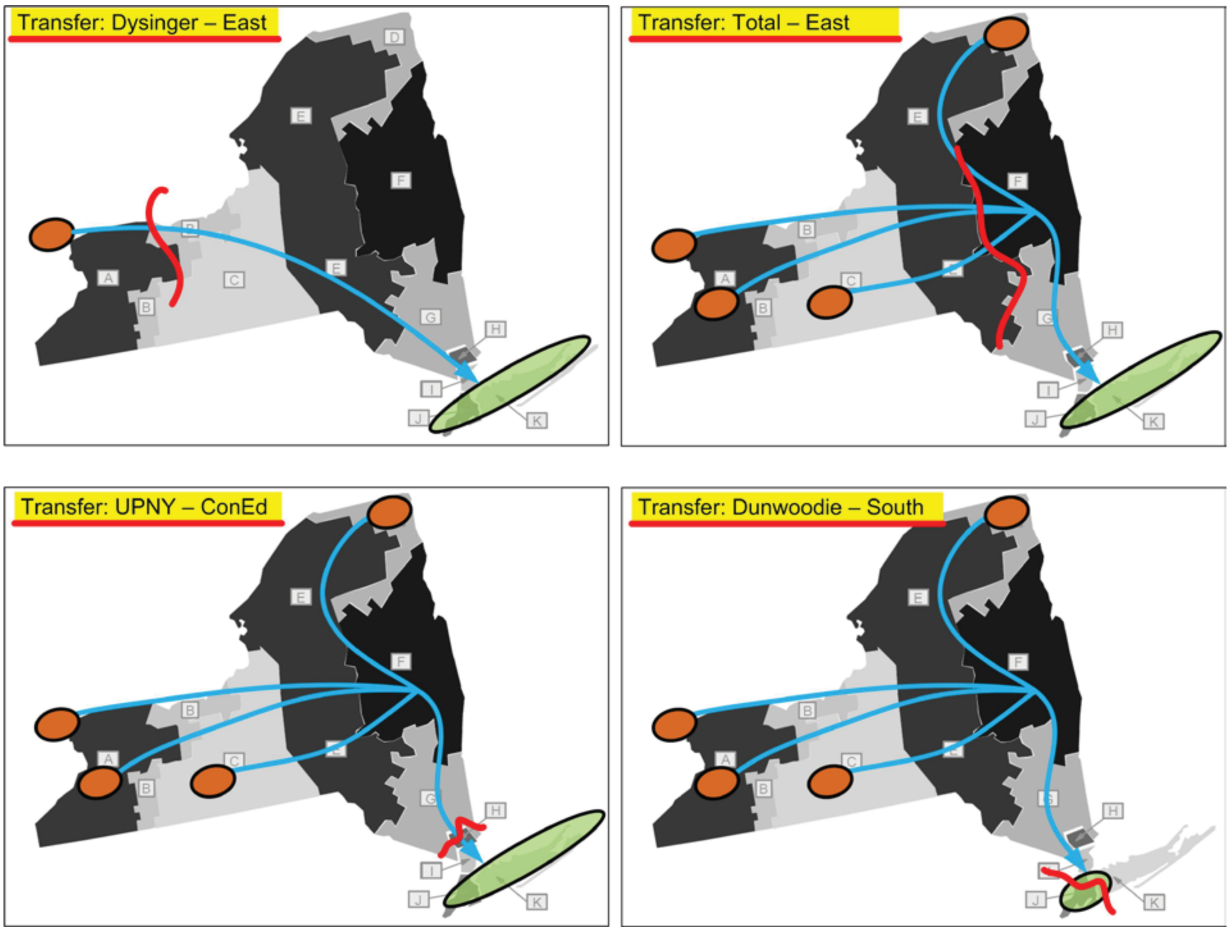


Figure 6-4: Transfers being used in the NYISO VCA study

The sink subsystems consist of the NY systems load centers Zone J (New York City) and Zone K (Long Island). Except for the Dysinger-East transfer (where several Lambton and Nanticoke units in IESO are considered only) the source subsystems are defined as combination of generating units from as IESO, West, Central and North.

The transfers are key components in this study, which contribute in stressing the system. Also, the information defined in the transfer scenarios need to accurately be represented in the powerflow basecases. Nevertheless, it was noticed that all the generating units identified in the transfers were either out of service or at their maximum output in all three basecases. This information is tabulated in Table 6-3.

Table 6-3: Transfer scenarios and status of generating units within the source subsystems

No	Transfer file name (Transfer name)	Subsystem name	Source		Powerflow Base Case		
					WIN	SUM	LL
			Bus #	%	Unit Status	Unit Status	Unit Status
1	DB2007_dyse.sub (Dysinger – East)	DE-G SHIFT	BUS 82765 BUS 81765	50 50	OUT OUT	OUT OUT	OUT OUT
2	DB2007_te.sub (Total –East)	TE-G SHIFT	BUS 76640 BUS 77051 BUS 77951 BUS 79515 BUS 81765 BUS 81422	5 5 50 10 15 15	IN IN IN IN OUT IN	IN IN IN IN OUT IN	OUT OUT OUT IN OUT OUT
3	DB2007_uc.sub (Upstate New York – ConEd)	UC-G SHIFT	BUS 76640 BUS 77051 BUS 77951 BUS 79515 BUS 81765 BUS 82765	5 5 50 10 15 15	IN IN IN IN OUT OUT	IN IN IN IN OUT OUT	OUT OUT OUT IN OUT OUT
4	DB2007_ds.sub (Dunwoodie – South)	DS-G SHIFT	BUS 76640 BUS 77051 BUS 77951 BUS 79515 BUS 81765 BUS 82765	5 5 50 10 15 15	IN IN IN IN OUT OUT	IN IN IN IN OUT OUT	OUT OUT IN OUT OUT OUT
IN = Units on this bus are in-service but operating at their maximum OUT = Units on this bus are out-of-service. These are brought in-service (with minimum MW = 0) for transfer setup							

After consultation with the relevant Transmission Operators all the out-of-service are brought in-service and their level of participation is adjusted in accordance with the percentage-share information provided in the original transfer definitions. These transfers have power flow in the order of 500 MW, 275 MW, and 150 MW for summer, winter, and light-load cases, respectively (Table 6-4).

Table 6-4: Transfer limits

No	Transfer name	Pre-contingency maximum transfer (Powerflow Basecases)		
		(SUM)	(WIN)	(LL)
1	Dysinger – East	500 MW	272 MW	147 MW
2	Total –East	501 MW	273 MW	147 MW
3	Dunwoodie – South	482 MW	292 MW	292 MW
4	UPNY – ConEd	722 MW	272 MW	147 MW

Contingencies

The contingencies that are examined in this study correspond to two separate sets (a) New York contingencies, and (b) Long Island contingencies. For the New York system, the contingencies are of the following types (i) Predefined contingencies, and (ii) N-1 contingencies.

The predefined contingency[2] set is provided by NYISO and are in-line with NERC's planning standard for contingency categories A, B, C, and D. This set includes tower contingencies, generation contingencies, series element contingencies, bus contingencies, stuck breaker contingencies, substation/branch contingencies, HVDC contingencies, inter-area contingencies (PJM) as well as a set of single contingencies and contingencies for new projects (a total of 525 contingencies).

The following contingencies were not run due to either conversion problems (conversion from PSS/E™-MUST to DSATools™-VSAT format) or run-time errors:

- Contingencies associated with generation or load dispatch (HVDC contingencies, Single contingencies such as *#120, #130, #190, #250*)
- Series element contingency named "SER HQ-NY 765 "
- Stuck breaker contingencies named "*SB MASS_765_7102"* and "*SB MASS_765_7108"*

The N-1 contingencies correspond to single tie-line outages and single branch outages for a subsystem termed as NYHV (outages for elements above 100kV for zones within the NY system). The NYHV subsystems are specified according to the transfers and are shown in Table 6-5.

Table 6-5: NYHV subsystems for N-1 contingency

Transfer DYSE		Transfer TE		Transfer UC		Transfer DS	
Zone #	**Name**	**Zone #**	**Name**	**Zone #**	**Name**	**Zone #**	**Name**
ZONE 13	NYPAWES	ZONE 3	NMPCMVN	ZONE 4	NMPCEAS	ZONE 24	ZONE-024
ZONE 1	NMPCWES	ZONE 7	NYSEGEA	ZONE 20	NYSEGNO	ZONE 25	ZONE-025
ZONE 5	NYSEGWE	ZONE 33	CENTHC	ZONE 21	NYPAF	ZONE 26	ZONE-026
ZONE 29	NMPCGNS	ZONE 18	NYPAE	ZONE 24	ZONE-024	ZONE 15	ZONE-015
ZONE 9	NYSEGHU	ZONE 20	NYSEGNO	ZONE 25	ZONE-025	ZONE 12	LIPA
ZONE 16	NYPAB	ZONE 4	NMPCEAS	ZONE 32	CEUPNY	ZONE 27	ZONE-027
ZONE 2	NMPCCEN	ZONE 21	NYPAF	ZONE 28	NYPAG	ZONE 22	-
ZONE 6	NYSEGCE	ZONE 8	NYSEGEA	ZONE 8	NYSEGEA	ZONE 23	ZONE-023
ZONE 17	NYPAC	ZONE 10	CENTHUD	ZONE 10	CENTHUD	ZONE 30	ZONE-030
ZONE 3	NMPCMVN	ZONE 11	O&R	ZONE 11	O&R		
ZONE 7	NYSEGEA	ZONE 28	NYPAG	ZONE 15	ZONE-015		
ZONE 18	NYPAE	ZONE 32	CEUPNY	ZONE 22	-		
ZONE 33	CENTHC			ZONE 23	ZONE-023		
				ZONE 30	ZONE-030		

The N-1 contingencies are generated using the DSATools™-VSAT contingency creation script using the criteria (ties and lines above 100 kV in given zones). For the Dysinger-East, Total-East, UPNY-Con, and Dunwoodies-South transfers, the total numbers of N-1 contingencies are 850, 508, 729, and 520, respectively. The Long-Island (Area 11) contingencies comprise a set of 149 contingencies. This set includes single line outage, multiple line outage, branch outage, and

[2] In order to make the contingency names compatible (number/type of characters) with the VCA-Offline BETA application, these were renamed (primarily the contingency type acronym is truncated) and a list of modifications is provided as part of the report delivery.

generator tripping. Except for the contingency named "*AREA 11 O/L 74958-74959-1*" all the rest were successfully implemented in this study.

Data Preparation and Case Setup

By combining three powerflow basecases, four transfer scenarios, and three contingency files, a total of 36 cases were set in the VCA-Offline BETA application. This applications (running under MS Access 2007 platform) generates approximately 33,000 sets of files representing all the contingencies being studied. As part of the VCA identification process, this application also merges all the data files and filters the useful information for generating meaningful interpretation.

Table 6-6: Scenarios prepared for the study

Transfer	**Powerflow**		
	Summer	**Winter**	**Light-load**
Dysinger-East	SUM-DYSE-COM SUM-DYSE-LIPA SUM-DYSE-N1	WIN-DYSE-COM WIN-DYSE-LIPA WIN-DYSE-N1	LL-DYSE-COM LL-DYSE-LIPA LL-DYSE-N1
Total-East	SUM-TE-COM SUM-TE-LIPA SUM-TE-N1	WIN-TE-COM WIN-TE-LIPA WIN-TE-N1	LL-TE-COM LL-TE-LIPA LL-TE-N1
UPNY-ConEd	SUM-UC-COM SUM-UC-LIPA SUM-UC-N1	WIN-UC-COM WIN-UC-LIPA WIN-UC-N1	LL-UC-COM LL-UC-LIPA LL-UC-N1
Dunwoodies-South	SUM-DS-COM SUM-DS-LIPA SUM-DS-N1	WIN-DS-COM WIN-DS-LIPA WIN-DS-N1	LL-DS-COM LL-DS-LIPA LL-DS-N1

The powerflow solution and voltage stability assessment mechanism have been set to ignore missing buses, branches, etc. Also, controls for under load tap changers (ULTCs)[3], phase-shifters, static tap-changers, static phase-shifters, static series compensators, and discrete switched shunts are set only to operate in pre-contingency conditions. The transfer analysis is conducted up to the first limit and contingency analysis is carried out at the first point of insecurity. Subsequently the modal analysis is done at the last stable point (only the smallest mode is analyzed). This step considers a maximum of 200 buses for bus participation factor (BPF) calculations. For achieving powerflow solutions (which runs as the platform for voltage stability assessment) in a timely manner, control adjustments are allowed up to 50 iterations and total number of iterations is limited to 80.

VCA Identification and Result Inspection

The VCA-Offline BETA application automates the voltage stability (i.e., PV analysis) and modal analysis procedures and generates a list of eignevalues. Associated with each of these eignevalues or modes, are a number of buses that participate in the voltage collapse. The VCA application, however, requires manual intervention and inspection of each of these modes. In order to facilitate this process of result verification the following terms are introduced

[3] As per transmission operator's instructions.

- ***Local mode*** An unstable mode that is exhibited in a smaller part of the system and does not represent a significant area of interest. Addition of limited reactive resources in those localized voltage-weak areas may resolve the voltage problems. These modes can either be associated with actual voltage collapse or numerical issues (such as high line impedance with small local load). Nonetheless, elimination of such local modes is important in order to expose critical collapse areas.

- ***Critical mode*** An unstable mode that represents voltage collapse over a larger geographical area and potentially affects the system backbone. These modes are typically associated with a large number of buses (transmission or sub-transmission) and/or larger loads. The VCA study in essence aims at identifying these modes only.

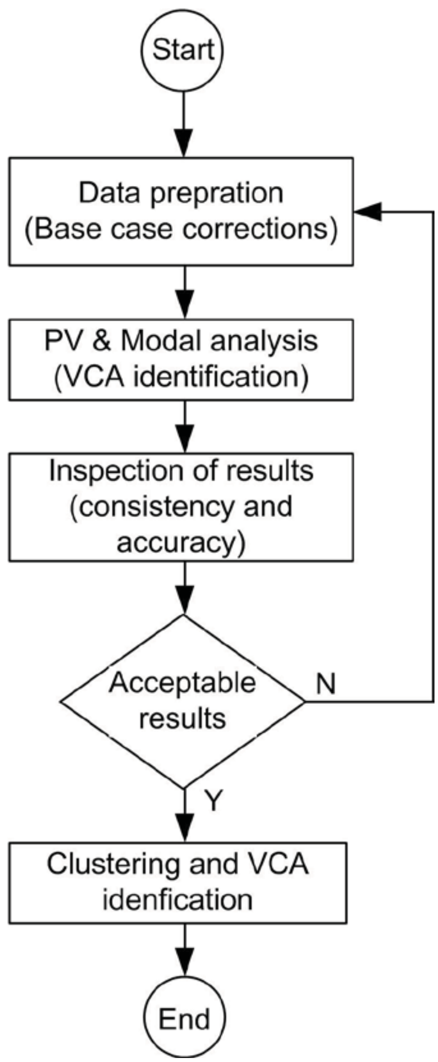


Figure 6-5: VCA identification activities

In addition to the concept of local and critical modes, there could be instances where a modal analysis may generate a list of buses that do not necessarily reflect any meaningful scenario. This could be exhibited by a combination of buses from widely sparse locations, which defies the fundamental understanding that voltage instability is a localized problem. In such cases, the results generated by the VCA program need to be investigated with finer details and the origin of the problem (in powerflow basecases) needs to be resolved. This iterative process is shown in Figure 6-5.

The complete process of VCA identification ie, PV analysis, modal analysis, clustering and pattern recognition, as well as determination of VCA generators is described in Section 4:. As a precursor to this step, further outline of Modal Analysis and its significant attributes are highlighted in Section 3. The method of reactive reserve calculation for each of the identified VCAs is discussed in Section 5.

The complete process of VCA identification typically takes six days of run-time on a Intel Dual-Core 2.4 GHz (1.98 GB RAM) machine. As outlined above, a significant portion of the time needs to be spent on evaluating the results of modal analysis. This step is critical in generating meaningful and accurate information.

Section 7: VCA Identification Study Results

The PV analysis and associated modal analysis using the New York bulk power transmission system (with three powerflow basecases, four transfers, and three sets of contingency files) have generated a total of 285 eigenvalues (modes). Most of these modes are reflective of voltage collapses that are of critical nature (as against local modes). These modes, after clustering with a bus participation factor threshold of 0.5 (and other relevant parameters as shown in Figure 7-1) indicates a total of four voltage critical areas (VCAs) within the New York system.

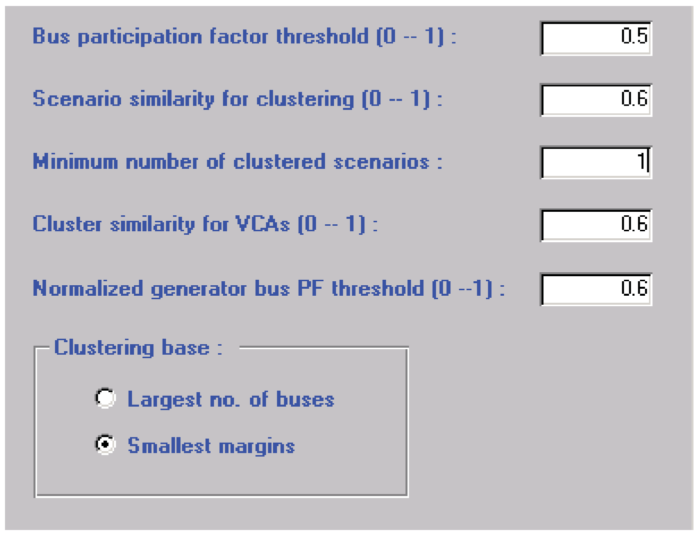
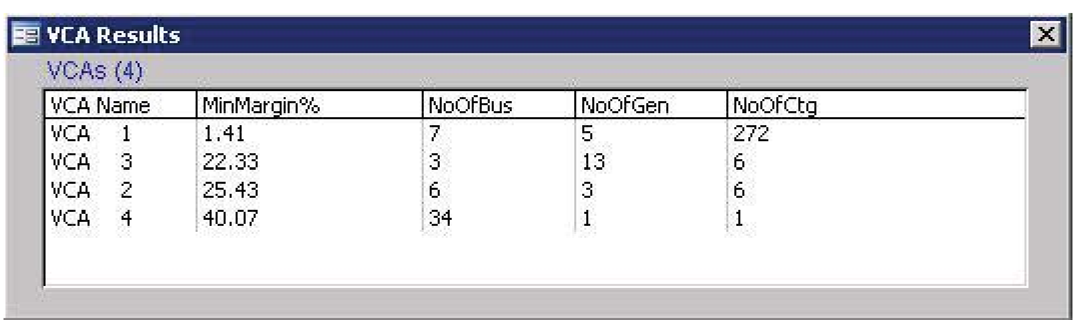


Figure 7-1 VCA identification parameters

It has been found that the VCA identification process is wholly dependent on the summer base case. Three of these VCAs are within the New York City area (Area 1XX0, Zone 1XX5, Owner CXXD), while the remaining VCA is in the CAPITAL area (Area 6XX, Zone 2XX1, Owner NXXG).



VCA Results

VCAs (4)

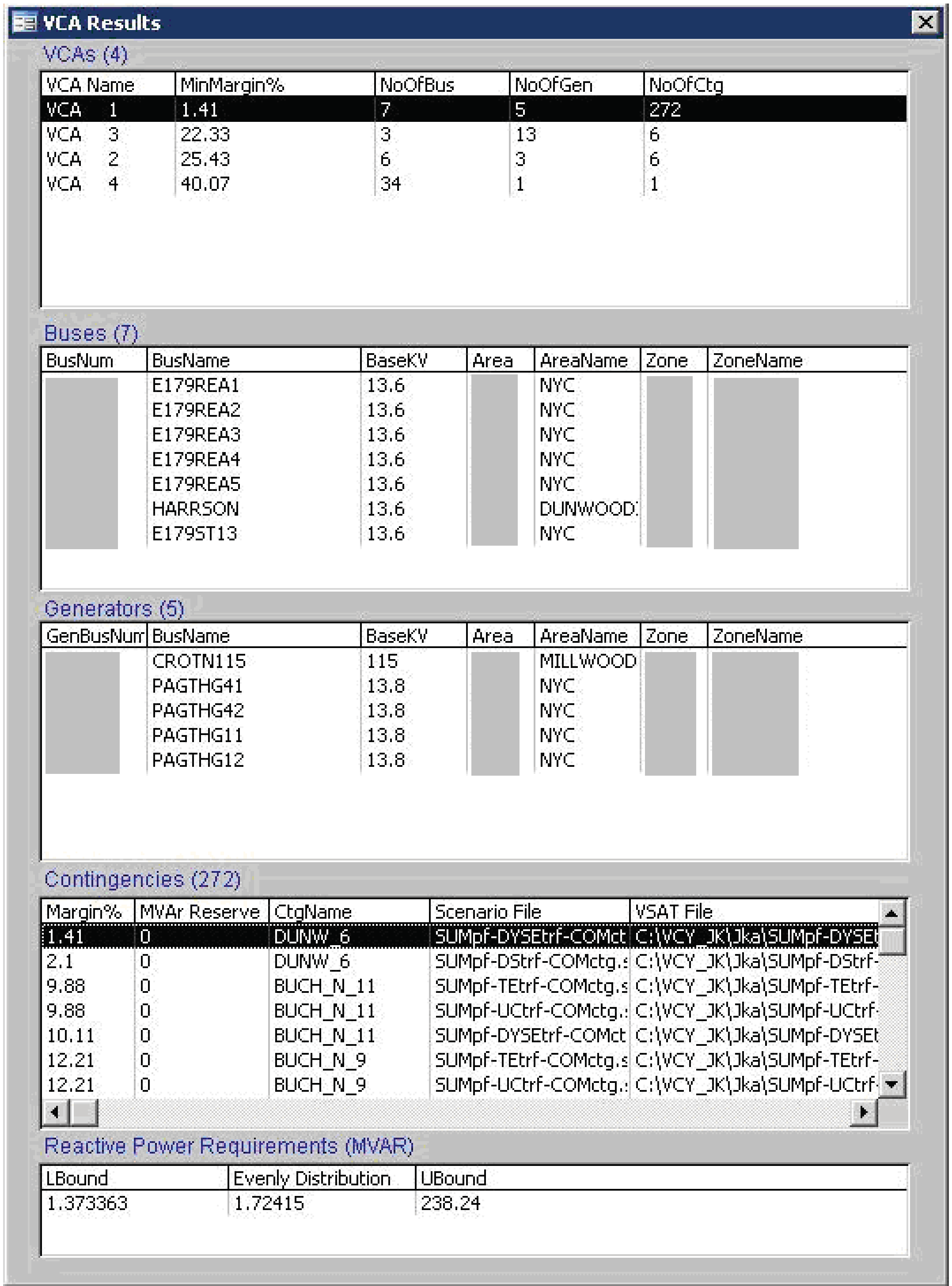
VCA Name	MinMargin%	NoOfBus	NoOfGen	NoOfCtg
VCA 1	1.41	7	5	272
VCA 3	22.33	3	13	6
VCA 2	25.43	6	3	6
VCA 4	40.07	34	1	1

Figure 7-2: The identified voltage critical areas within the NYISO system

While each of the VCA is discussed further in this section, it has been proposed that the VCA# 1,#2, and #3 be treated as a single voltage critical area. This, however, depends on the utility owner/operator's perception of the voltage problem and geographical/electrical proximity of these VCAs. On the contrary, VCA # 4 can be treated as local voltage problem, and may not be considered as a true VCA. Nonetheless, relevant results for this VCA are provided in this report, with a view to allowing the end-user to evaluate further.

VCA#1 Located near Station EST_XX (Area 1XX0, Zone 1XX5, Owner CXXD)

In Figure 7-3 highlights of the VCA # 1 is shown and further representations are given through Figure 7-4 and Figure 7-5. It can be seen that a total of six buses are associated with this mode and 272 eigenvalues reflect this area of voltage collapse.



VCA Results

VCAs (4)

VCA Name	MinMargin%	NoOfBus	NoOfGen	NoOfCtg
VCA 1	1.41	7	5	272
VCA 3	22.33	3	13	6
VCA 2	25.43	6	3	6
VCA 4	40.07	34	1	1

Buses (7)

BusNum	BusName	BaseKV	Area	AreaName	Zone	ZoneName
[redacted]	E179REA1	13.6	[redacted]	NYC	[redacted]	[redacted]
	E179REA2	13.6		NYC		
	E179REA3	13.6		NYC		
	E179REA4	13.6		NYC		
	E179REA5	13.6		NYC		
	HARRSON	13.6		DUNWOOD		
	E179ST13	13.6		NYC		

Generators (5)

GenBusNum	BusName	BaseKV	Area	AreaName	Zone	ZoneName
[redacted]	CROTN115	115	[redacted]	MILLWOOD	[redacted]	[redacted]
	PAGTHG41	13.8		NYC		
	PAGTHG42	13.8		NYC		
	PAGTHG11	13.8		NYC		
	PAGTHG12	13.8		NYC		

Contingencies (272)

Margin%	MVAr Reserve	CtgName	Scenario File	VSAT File
1.41	0	DUNW_6	SUMpf-DYSEtrf-COMct	C:\VCY_JK\Jka\SUMpf-DYSEt
2.1	0	DUNW_6	SUMpf-DStrf-COMctg.s	C:\VCY_JK\Jka\SUMpf-DStrf-
9.88	0	BUCH_N_11	SUMpf-TEtrf-COMctg.s	C:\VCY_JK\Jka\SUMpf-TEtrf-
9.88	0	BUCH_N_11	SUMpf-UCtrf-COMctg.s	C:\VCY_JK\Jka\SUMpf-UCtrf-
10.11	0	BUCH_N_11	SUMpf-DYSEtrf-COMct	C:\VCY_JK\Jka\SUMpf-DYSEt
12.21	0	BUCH_N_9	SUMpf-TEtrf-COMctg.s	C:\VCY_JK\Jka\SUMpf-TEtrf-
12.21	0	BUCH_N_9	SUMpf-UCtrf-COMctg.s	C:\VCY_JK\Jka\SUMpf-UCtrf-

Reactive Power Requirements (MVAR)

LBound	Evenly Distribution	UBound
1.373363	1.72415	238.24

Figure 7-3: Details of VCA#1 (for masked information please see Section A-4)

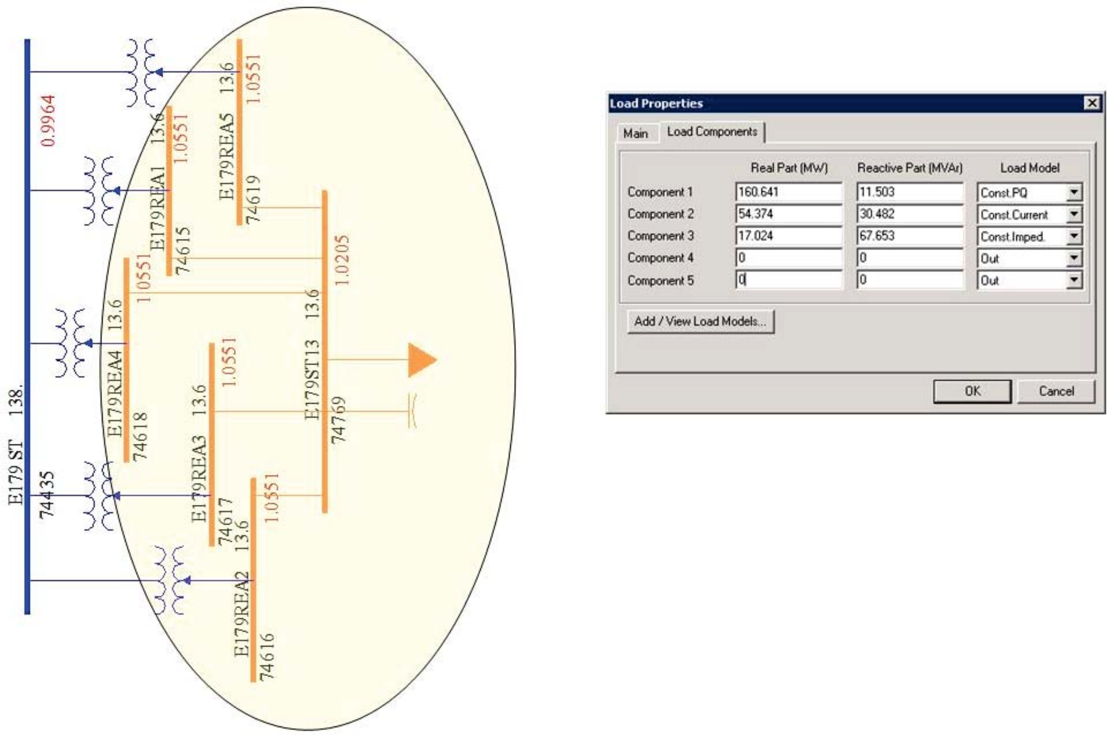


Figure 7-4: Single line diagram and load for the VCA # 1

The total load connected through these buses is above 230 MW / 100 MVAr. Also, these buses are coupled to 138 kV bus in the EST_XX Station. Voltage collapse characteristics in these buses are also shown in Figure 7-5 for contingency 'TWR 69/J&70/K'.

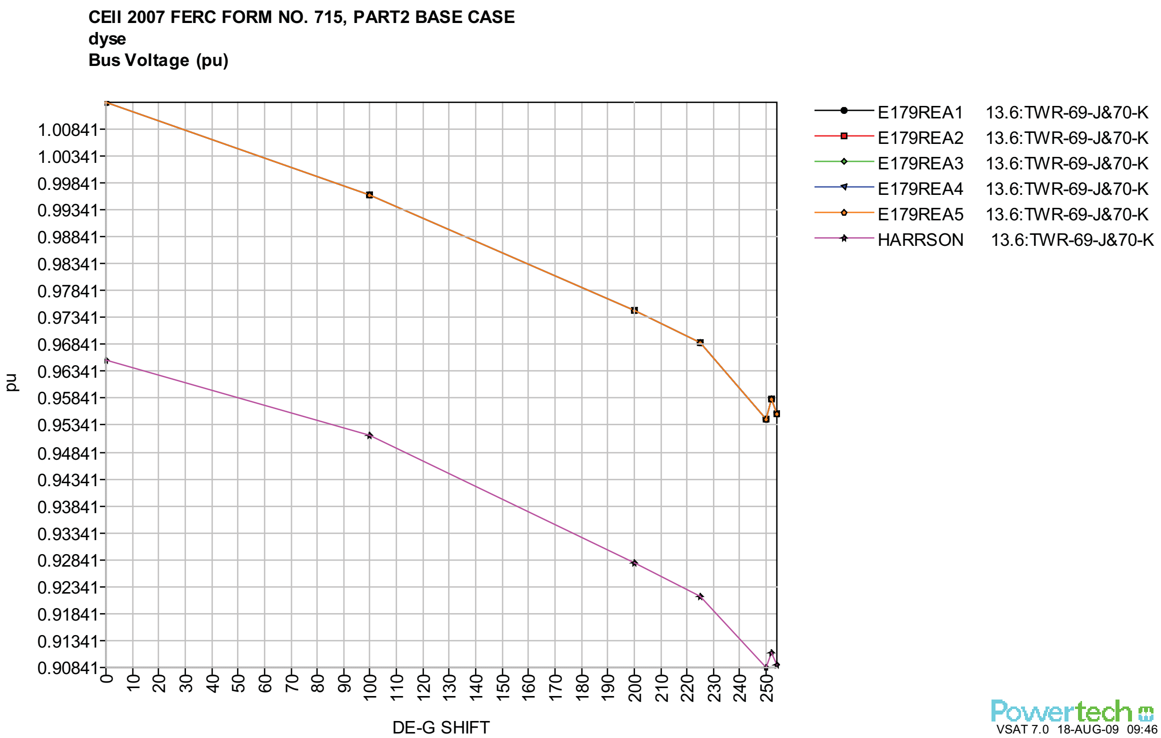


Figure 7-5: Voltage collapse profile of buses within VCA # 1

VCA#2 Located near Station FRG_XX (Area 1XX0, Area 1XX5, Owner CXXD)

Highlights of the VCA#2 is shown through Figure 7-6, Figure 7-7, and Figure 7-8. Two stuck breaker contingencies ('SB FARR_345_5E', 'SB FARR_345_6E') are associated with this voltage critical area.

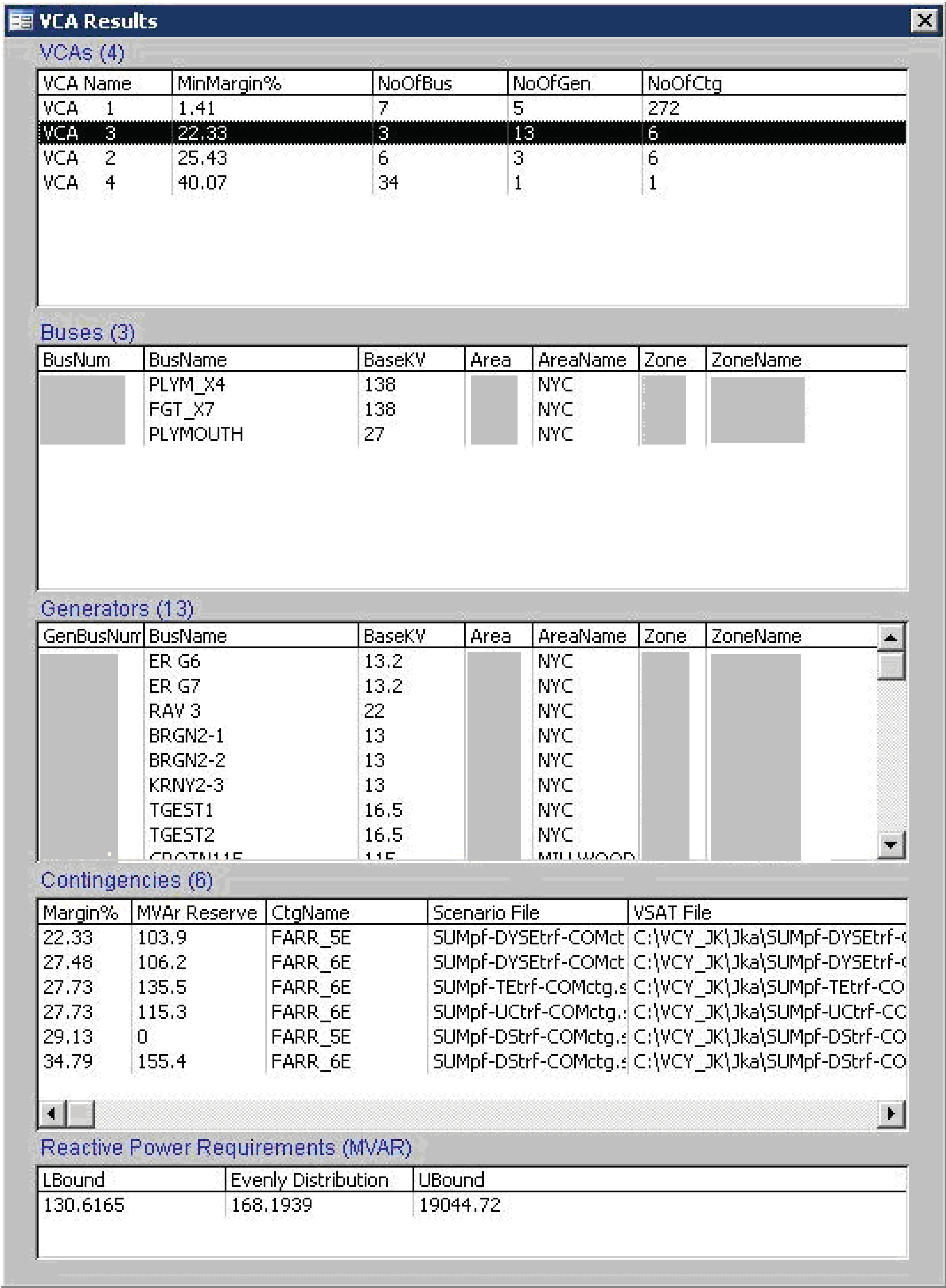


Figure 7-6: Details of VCA#2 (for masked information please see Section A-4)

This area is characterized by around 370 MW/ 160 MVAr load and several 138 kV buses. In Figure 7-8 voltage collapse profile within these buses is plotted for contingency 'SB FARR_345_5E'.

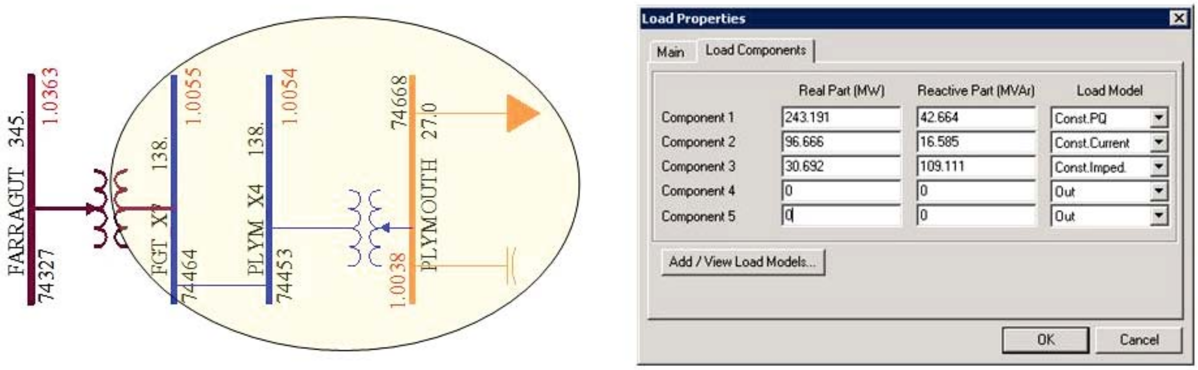


Figure 7-7: Single line diagram and load for the VCA # 2

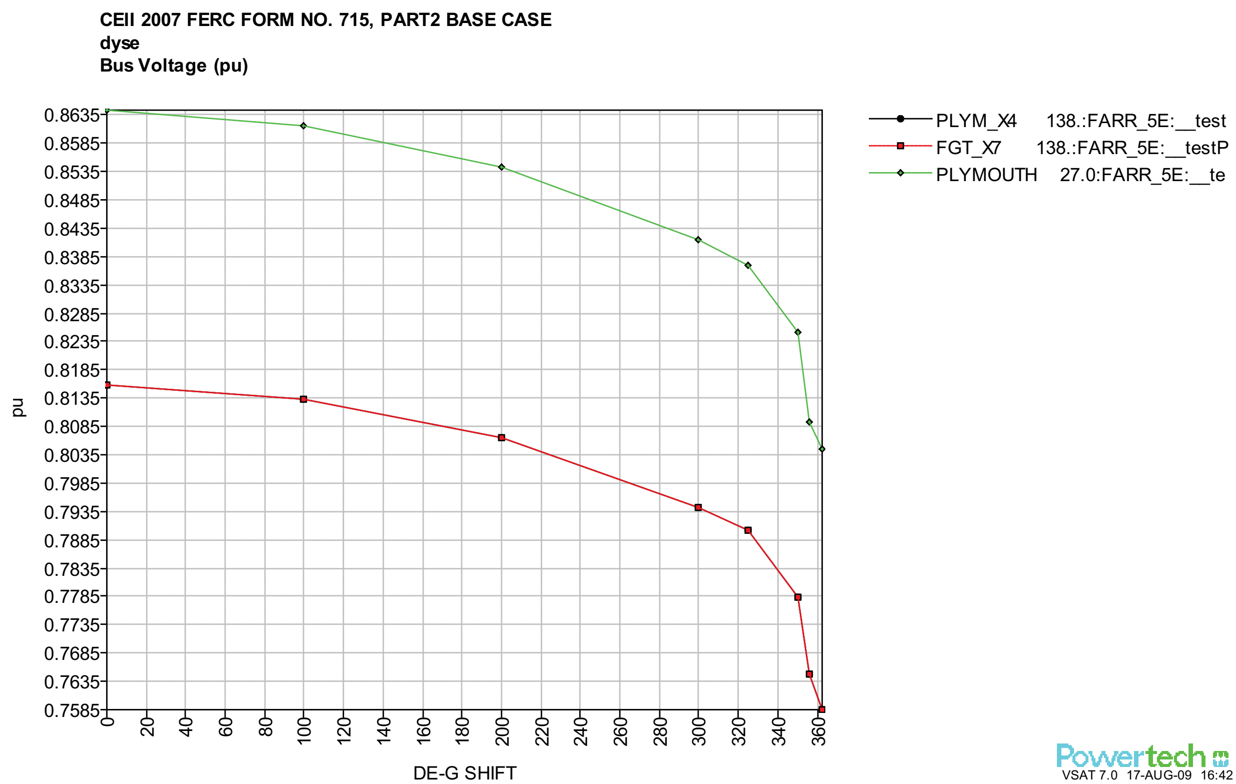
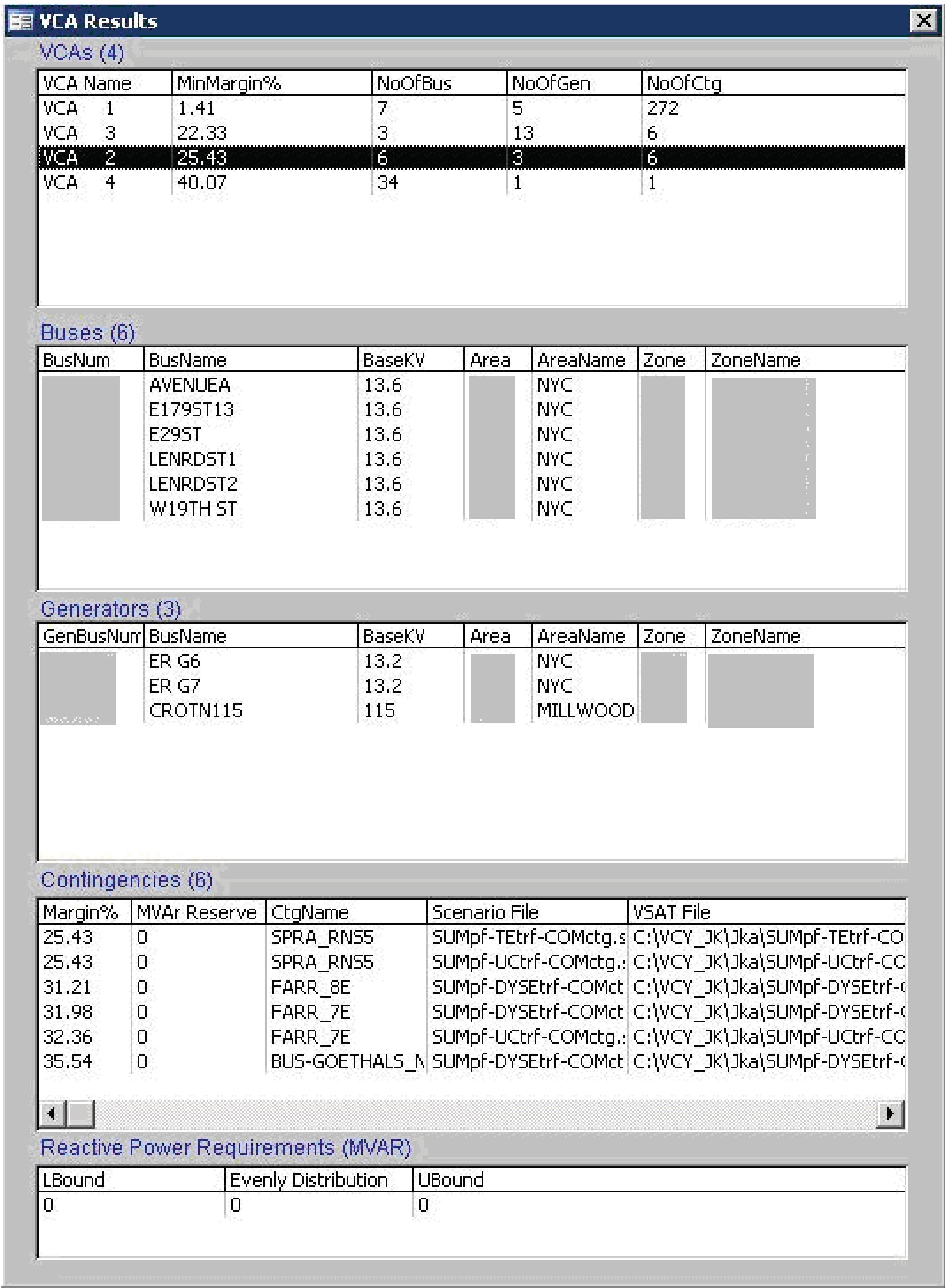


Figure 7-8: Voltage collapse profile of buses within VCA # 2

VCA#3 Located near Station ERV_XX (Area 1XX0, Area 1XX5, Owner CXXD)

A set of six buses (13.6 kV) are associated with VCA#3 and 6 modes reflect this voltage critical area.



VCA Results

VCAs (4)

VCA Name	MinMargin%	NoOfBus	NoOfGen	NoOfCtg
VCA 1	1.41	7	5	272
VCA 3	22.33	3	13	6
VCA 2	25.43	6	3	6
VCA 4	40.07	34	1	1

Buses (6)

BusNum	BusName	BaseKV	Area	AreaName	Zone	ZoneName
	AVENUEA	13.6		NYC		
	E179ST13	13.6		NYC		
	E29ST	13.6		NYC		
	LENRDST1	13.6		NYC		
	LENRDST2	13.6		NYC		
	W19TH ST	13.6		NYC		

Generators (3)

GenBusNum	BusName	BaseKV	Area	AreaName	Zone	ZoneName
	ER G6	13.2		NYC		
	ER G7	13.2		NYC		
	CROTN115	115		MILLWOOD		

Contingencies (6)

Margin%	MVAr Reserve	CtgName	Scenario File	VSAT File
25.43	0	SPRA_RNS5	SUMpf-TEtrf-COMctg.s	C:\VCY_JK\Jka\SUMpf-TEtrf-CO
25.43	0	SPRA_RNS5	SUMpf-UCtrf-COMctg.:	C:\VCY_JK\Jka\SUMpf-UCtrf-CC
31.21	0	FARR_8E	SUMpf-DYSEtrf-COMct	C:\VCY_JK\Jka\SUMpf-DYSEtrf-(
31.98	0	FARR_7E	SUMpf-DYSEtrf-COMct	C:\VCY_JK\Jka\SUMpf-DYSEtrf-(
32.36	0	FARR_7E	SUMpf-UCtrf-COMctg.:	C:\VCY_JK\Jka\SUMpf-UCtrf-CC
35.54	0	BUS-GOETHALS_N	SUMpf-DYSEtrf-COMct	C:\VCY_JK\Jka\SUMpf-DYSEtrf-(

Reactive Power Requirements (MVAR)

LBound	Evenly Distribution	UBound
0	0	0

Figure 7-9: Details of VCA#3 (for masked information please see Section A-4)

As seen in Figure 7-10, the single line diagram of a pair of 13.6 kV systems is shown. The total load at each of these 13.6 kV buses is around 250 MW/ 100 MVAr.

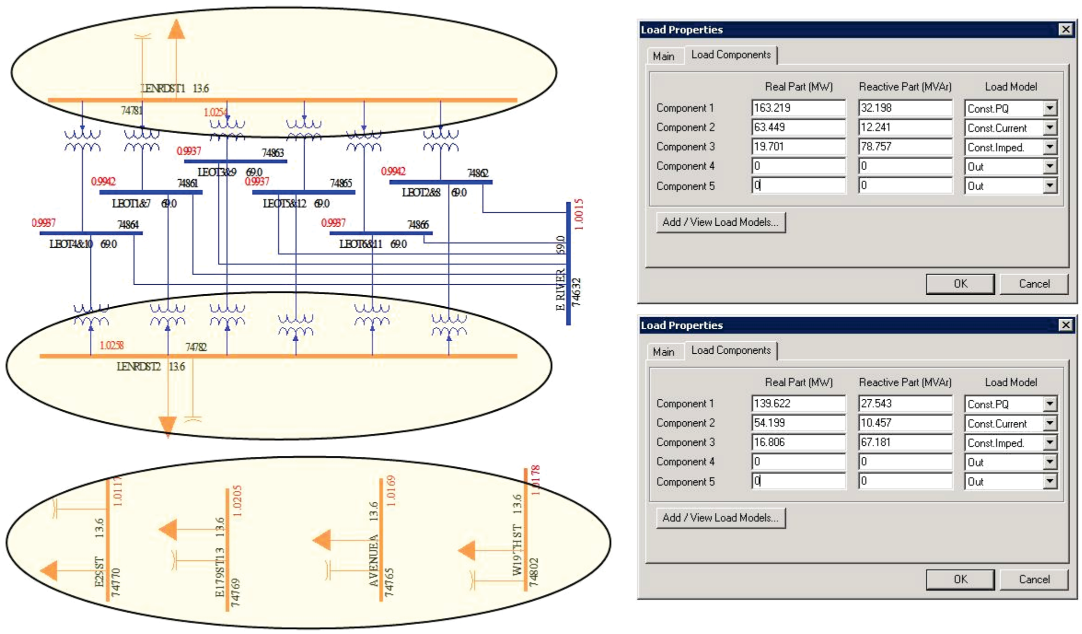


Figure 7-10: Single line diagram and load for the VCA # 2

A set of voltage curves showing the voltage collapse characteristics in these buses is shown in Figure 7-11. This case represents the scenario with Total-East transfer (summer powerflow and contingency 'SB SPRA_345_RNS5').

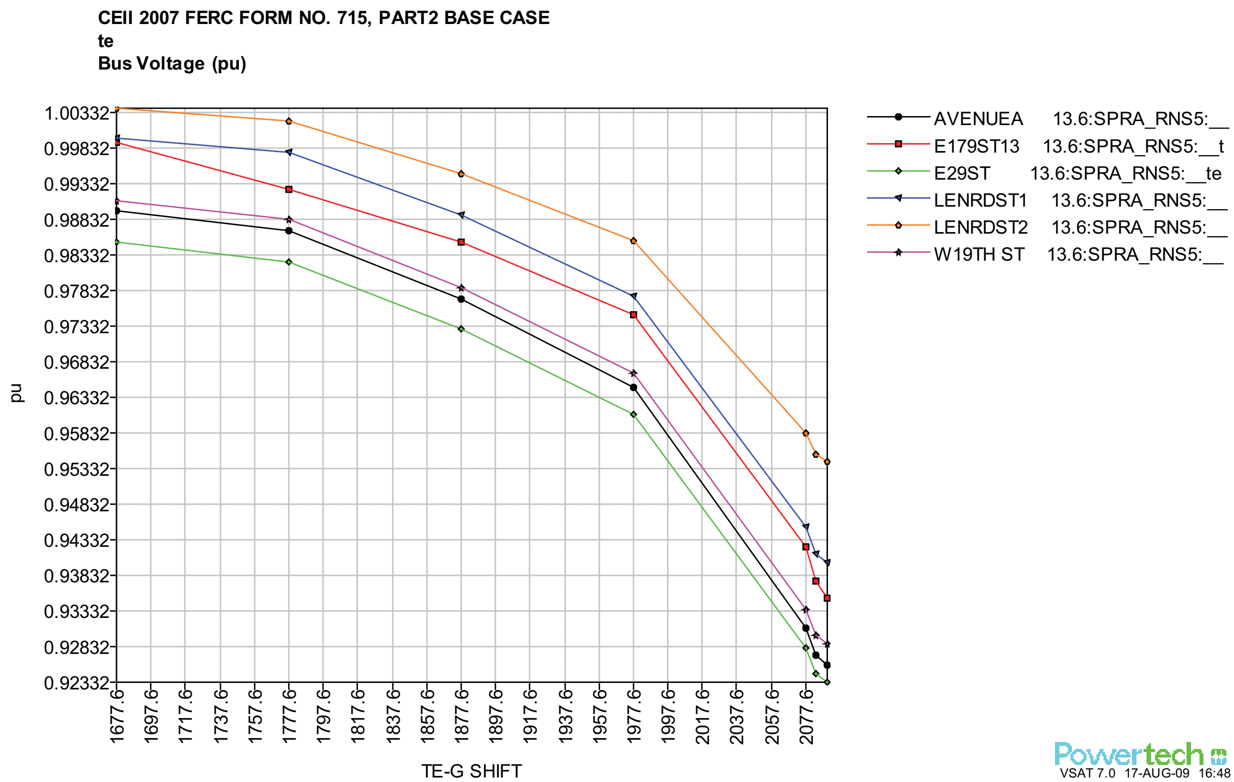


Figure 7-11: Voltage collapse profile of buses within VCA # 3

VCA#4 Located near Station KNC_XX (Area 6XX, Zone 2XX1, Owner NXXG)

The VCA#4 is located in the Capital area (Area 6XX) and contains 34 buses (including two 115 kV buses). This VCA is associated with only one contingency (Auto-generated N-1 contingency named ‘A 386 Branch outage between Bus # 75435 and 75443).

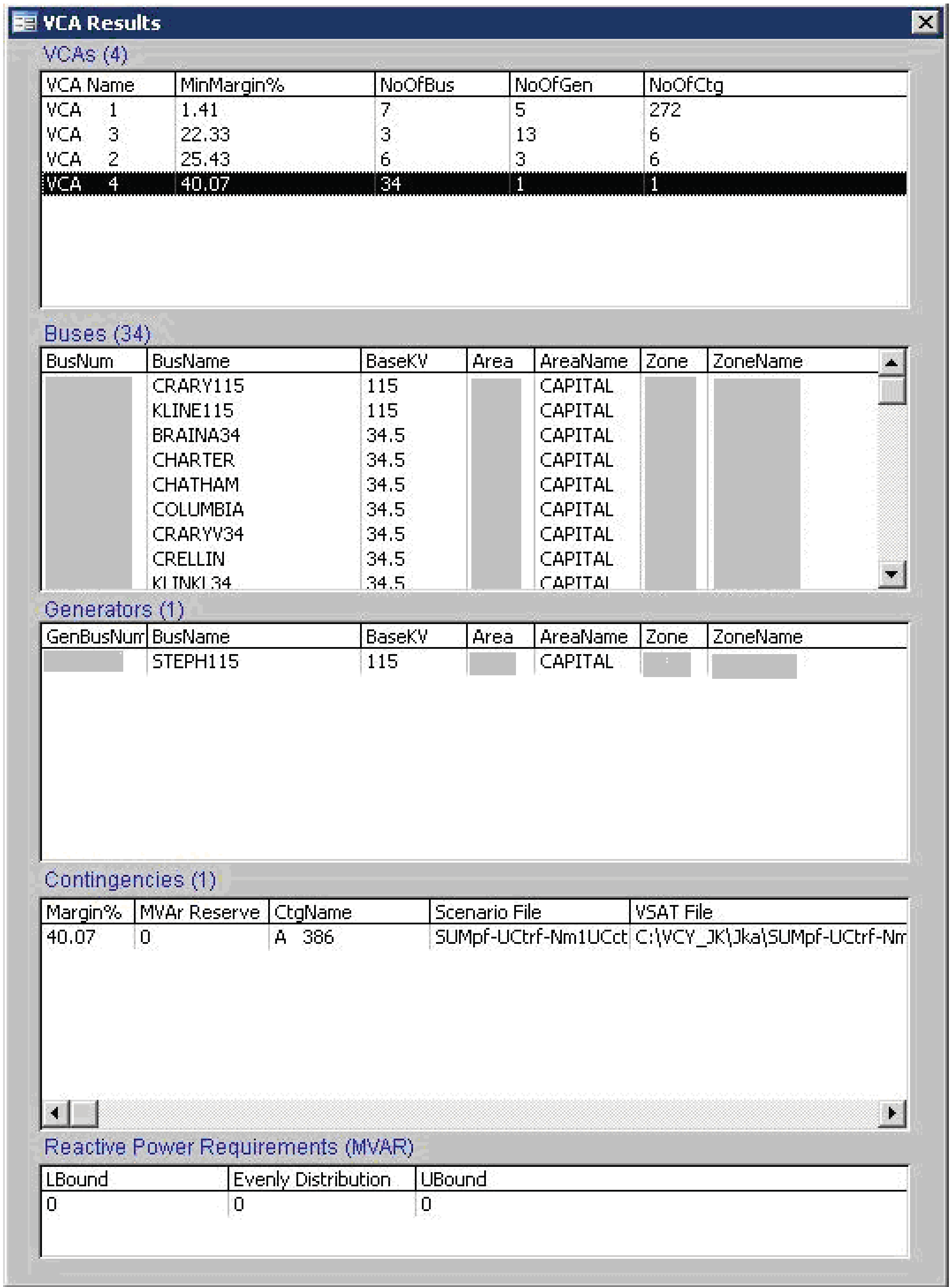


Figure 7-12: Details of VCA # 4 (for masked information please see Section A-4)

In Figure 7-13 a single line diagram of the pertinent system is shown. It can be observed that unlike many weak distribution-level loads connected through radial lines, this area is a meshed system and potentially envelope a wider geographical area.

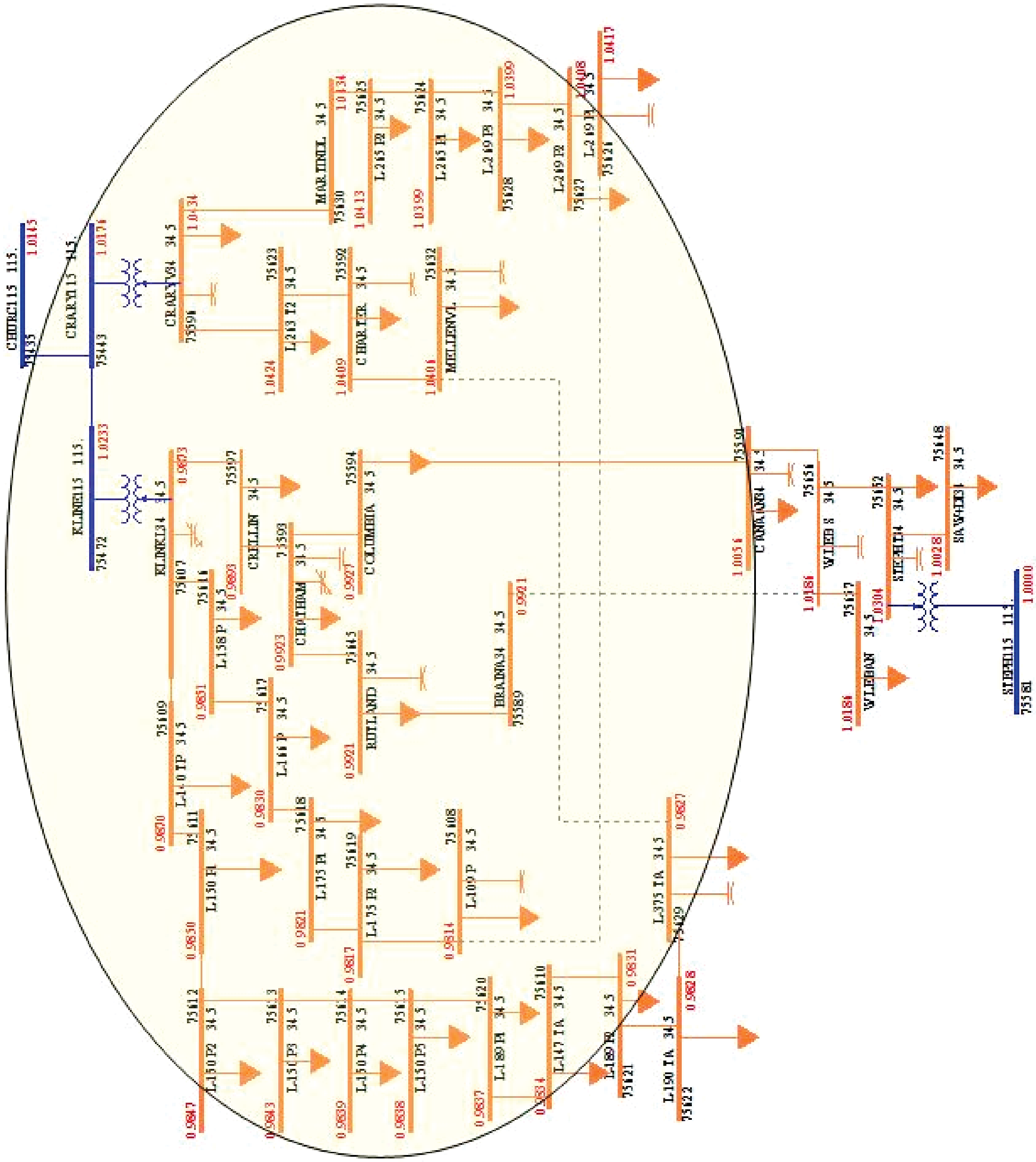


Figure 7-13: Single line diagram for the VCA # 4

In Figure 7-14 the voltage collapse profiles of several buses (six buses with highest participation) are shown. Unlike other PV curves presented earlier, this curve exhibits the effects of control/switching actions (tap changers, switchable shunts, etc.) through its uneven profile.

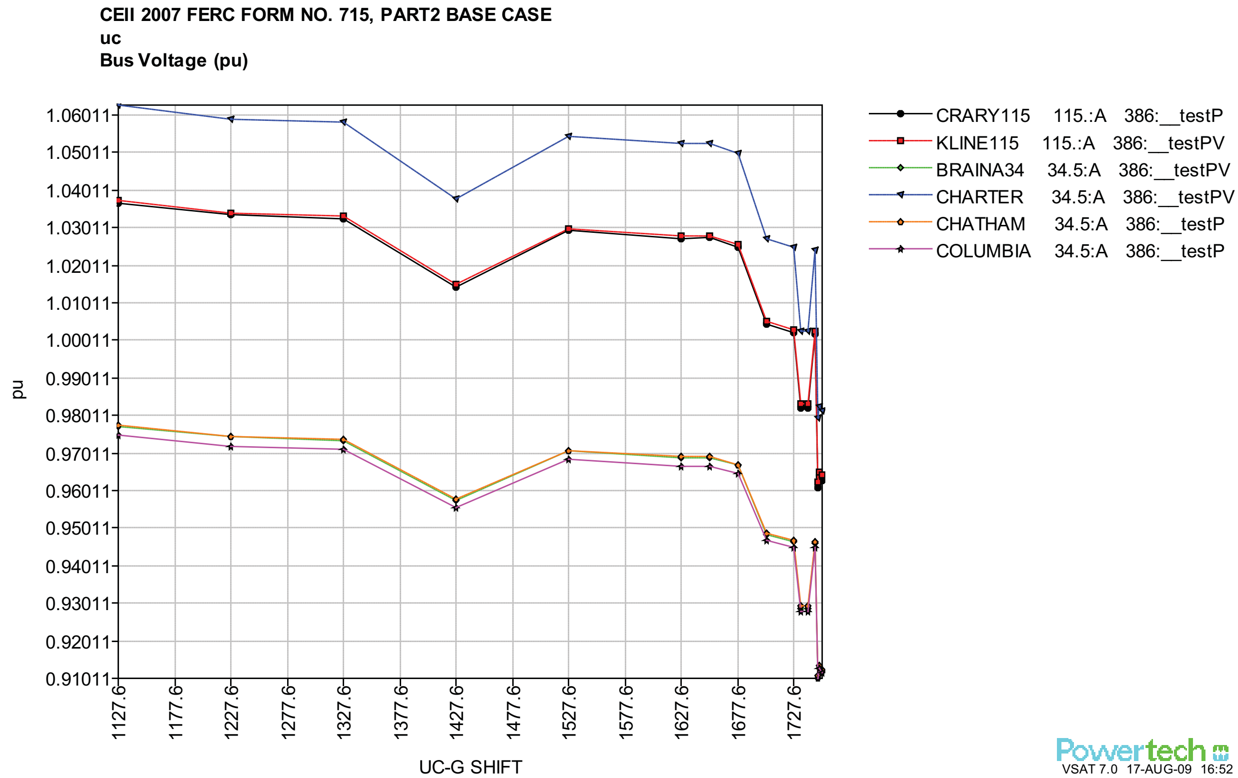


Figure 7-14: Voltage collapse profile of buses within VCA # 4

The required reactive power to maintain on the generators that control voltage stability in the above weak areas (with required stability margin of 5%) varies for each area. Also, it is important to note that since VCA 2, 3, and 4 have very high margins (>22%), there is no need to specify any reactive power requirement for them. The required reactive power of on the controlling generators in the weak area 1 (VCA #1) is approximately 230 MVAR. It is also important to consider how many contingencies are supporting a specific VCA when the reactive power requirement is being sought. An example is the VCA #4. In this VCA there are 34 buses with one controlling generator. This VCA is only supported by one contingency.

Section 8: Conclusions and Recommendations

The NYISO voltage critical area (VCA) identification study considers a set of three powerflow basecases (Summer-peaking, winter-peaking, and light load for year 2012), four cross-state transfer scenarios, and a number of pre-defined as well as N-1 contingencies. EPRI/Powertech's VCA-Offline BETA program has been used in identifying the VCAs and corresponding reactive reserve requirements.

This software tool has revealed a total of four VCAs, which are:

- VCA#1: Located near Station EST_XX (Area 1XX0, Area 1XX5, Owner CXXD)
- VCA#2: Located near Station FRG_XX (Area 1XX0, Area 1XX5, Owner CXXD)
- VCA#3: Located near Station ERV_XX (Area 1XX0, Area 1XX5, Owner CXXD)
- VCA#4: Located near Station KNC_XX (Area 6XX, Zone 2XX1, Owner NXXG)

According to this study, the minimum transfer margin associated with VCA#1, is well below the required stability criteria of 5%. The required reactive power of the controlling generators in this weak area (VCA #1) is approximately 230 MVAR. Since VCA 2, 3, and 4 have very high margins (>22%), there is no need to specify any reactive power requirement for them.

Pursuant discussions have revealed that:

- considering the geographical proximity and network configurations, VCA#1, #2, and #3 can apparently be treated as a single VCA.
- considering the fact that VCA#4 is reflective of a local load distribution issue, this VCA can be ignored.

It has also been observed that the current VCA-Offline BETA program needs to be advanced such that elements of utility owner/operator's experience can be incorporated into the program intelligence.

Even with significant due-diligence efforts in correcting the powerflow basecases, setting the scenarios, and inspecting the outcomes, the results of this study may contain subtle inconsistencies with practical experiences and knowledge, and may not be indicative of the actual performance. Possible future activities in this regard include:

- Develop interpretations of this study through system operator/owners' experience
- Advance the VCA-Offline BETA application to a more robust and faster product
- Conduct further study on the NYISO system (with inter-state transfers and reduced powerflow basecases)

Section 9: References

1. EPRI, Identification of Critical Voltage Control Areas and Determination of Required Reactive Power Reserves Status Report, Sept. 2007. URL http //my.epri.com/portal/server.pt?Abstract_id=000000000001013995
2. EPRI, VCA Offline (Identification of Critical Voltage Control Areas)- BETA, July 2009. URL http //my.epri.com/portal/server.pt?Abstract_id=000000000001019370.
3. "Voltage Stability Assessment Concepts, Practices and Tools", IEEE Power Engineering Society, Power System Stability Subcommittee Special Publication, August 2002.
4. R. A. Schlueter, "A Voltage Stability Security Assessment Method," IEEE Trans. Power Syst., Vol. 13, pp. 1423–1438, Nov. 1998.
5. R. A. Schlueter, S. Liu, K. Ben-Kilian, "Justification of the Voltage Stability Security Assessment and Diagnostic Procedure Using a Bifurcation Subsystem Method", IEEE Trans. Power Syst., Vol. 15, pp. 1105–1111, Aug. 2000
6. C. A. Aumuller, T.K. Saha, "Determination of Power System Coherent Bus Groups by Novel Sensitivity-Based Method for Voltage Stability Assessment", IEEE Trans. Power Syst., Vol. 18, No.3, pp. 1157–1164, Aug. 2003
7. G.E.Tovar, J.G. Calderon, V.E. de la Torre, F.I. Nieva, "Reactive Reserve Determination Using Coherent Clustering Applied to the Mexican Norwest Control Area", Power Systems Conference and Exposition, PSCE 2004, New York City, Oct.10-13, 2004
8. S. Grijalva, P.W. Sauer, "Static Collapse and Topological Cuts", 38th Annual Hawaii International Conference on System Science, Waikoloa, HI, Jan. 5-8, 2005
9. J. Zhong, E. Nobile, A. Bose and K. Bhattacharya "Localized Reactive Power Markets Using the Concept of Voltage Control Areas," IEEE Trans. Power Syst., Vol. 19, No.3, pp. 1555–1561, Aug. 2004
10. R.A. Schlueter, I. Hu, M.W. Chang, J.C. Lo, and A. Costi, "Methods for Determining Proximity to Voltage Collapse," IEEE Trans. on Power Systems, Vol. 6, No. 2, pp. 285-292, 1991
11. T. Lie, R.A. Schlueter, P.A. Rusche, and R. Rhoades, "Method of Identifying Weak Transmission Network Stability Boundaries," IEEE Trans. on Power Systems, Vol. 8, No. 1, pp. 293-301, February 1993
12. M.K. Verma, S.C. Srivastava, "Approach to Determine Voltage Control Areas Considering Impact of Contingencies", IEE Proc.-Gener. Trans. Distrib. Vol. 152, No. 3, May 2005
13. H. Liu, A. Bose, V. Vencatasubramanian, "A Fast Voltage Security Assessment Method Using Adaptive Bounding", IEEE Trans. Power Syst., Vol. 15, No.3, pp. 1137–1141, Aug. 2000
14. P. Lagonotte, J.C. Sabonnadiere,J.Y. Leost, and J.P. Paul, "Structural analysis of the electrical system Application to secondary voltage control in France", IEEE Trans. Power Syst., Vol. 4, No.2, pp. 479–485, Aug. 1989
15. J. Zaborszky et.al., "Fast Contingency Evaluation using Concentric Relaxation", IEEE Trans. Power Syst., Vol. PAS-99, pp 28-36, January 1980,

16. B. Gao, G.K. Morison, P. Kundur, “Voltage Stability Evaluation Using Modal Analysis”, IEEE Trans. Power Syst., Vol.7, No.4pp1529-1542, November 1992,
17. P. Kundur, Power Systems Stability and Control, McGraw-Hill, New York, 1994
18. NYISO, 2009 Comprehensive Reliability Plan Comprehensive System Planning Process; FINAL REPORT; May 19, 2009; URL http //www.nyiso.com/public/services/planning/reliability_assessments.jsp
19. NYISO, 2009 Load & Capacity Data “Gold Book”; April 2009; URLhttp //www.nyiso.com/public/services/planning/planning_data_reference_documents.jsp
20. http //www.ferc.gov/market-oversight/mkt-electric/new-york.asp#geo
21. NYISO Operating Study Summer 2009; May 14, 2009; URL http //www.nyiso.com/public/

Appendix

Section A-1: Reactors and Capacitor Settings

Table A - 1.1: Information received on the reactors and capacitors

Contents	Actions (General*)	Actions (Specific)	Numbers
Switchable caps	- In-service Summer - Out-of-service Fall/Winter/Spring	-Con Ed Reactors and Caps.xls (Switchable Caps)	~ 60
Shunt reactors	--	-Shunt Reactor rev 2 ConEd.xls	~ 20
Series reactors	- In-service for Summer - Bypass for Fall/Winter/Spring	-SO03-34-0.doc -Con Ed Reactors and Caps.xls (Switchable Series Reactors)	~ 5
SVCs and StatComs	--	-SVC Control Strategies.doc	~ 3

- As per conference call on Monday, April 06, 2009 10 00 AM-11 00 AM. With Matt Koenig/ConEd (koenigm@coned.com)

Table A - 1.2: Series Reactors and settings

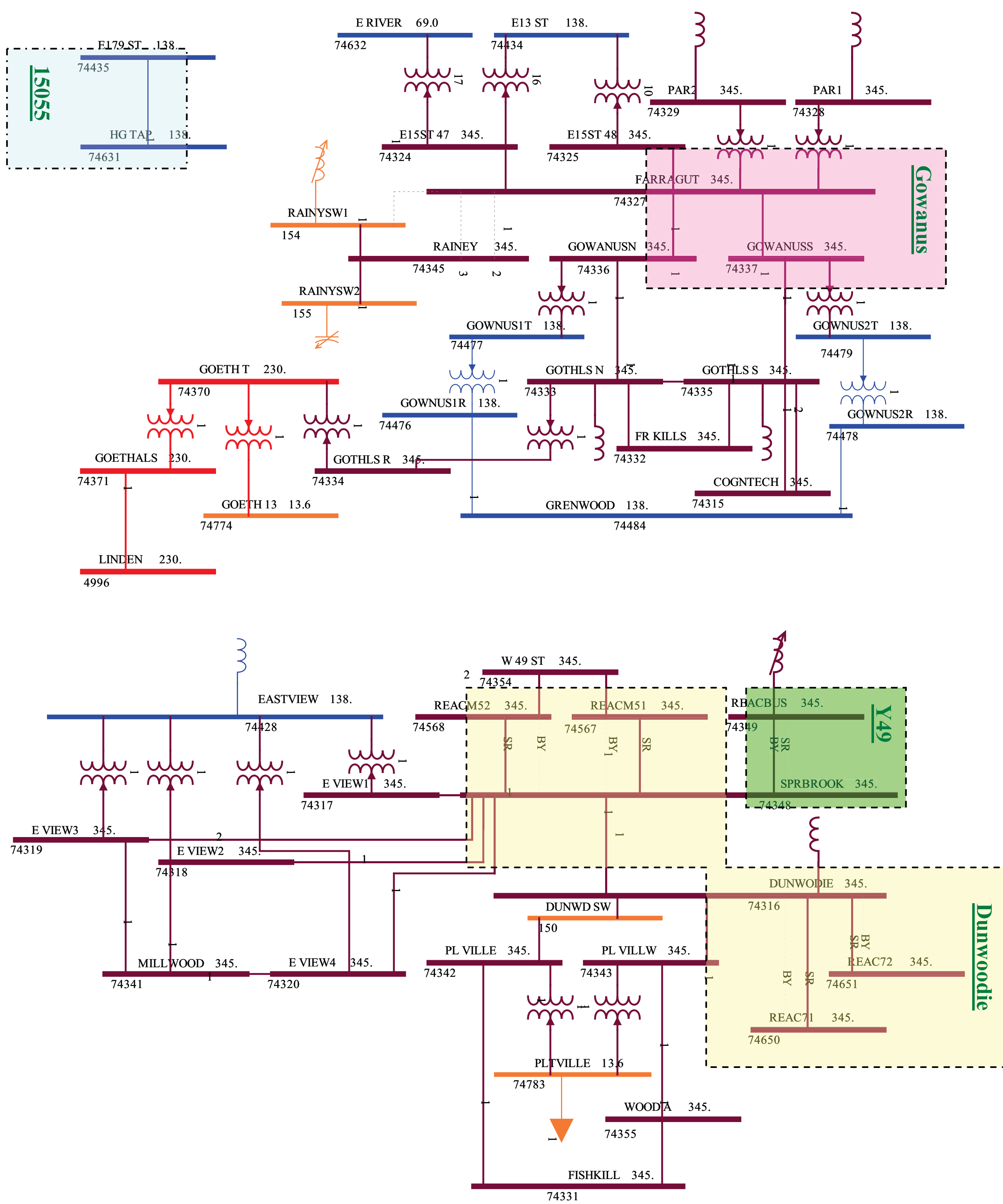
								Status in Original PF			Status in Study PF			
Name	**From bus**	**From bus name**	**To bus**	**To bus name**	**Id**	**Line R (pu)**	**Line X (pu)**	**LL**	**SUM**	**WIN**	**LL**	**SUM**	**WIN**	**Comment**
15055	74435	E179 ST 138.0	74631	HG TAP 138.0	1	0.00095	0.05756	IN	IN	IN	IN	IN	IN	1 (No change)
Dunwoodie Interface	74316	DUNWODIE 345.0	74650	REAC71 345.0	SR	0.00003	0.0326	OUT	IN	OUT	OUT	IN	OUT	2 (No change)
	74316	DUNWODIE 345.0	74651	REAC72 345.0	SR	0.00003	0.0326	OUT	IN	OUT	OUT	IN	OUT	
	74348	SPRBROOK 345.0	74567	REACM51 345.0	SR	0.00003	0.0326	OUT	IN	OUT	OUT	IN	OUT	
	74348	SPRBROOK 345.0	74568	REACM52 345.0	SR	0.00003	0.0326	OUT	IN	OUT	OUT	IN	OUT	
Y49	74348	SPRBROOK 345.0	74349	REACBUS 345.0	SR	0	0.0294	IN	OUT	IN	IN	OUT	IN	3 (No change)
Gowanus	74336	GOWANUSN 345.0	**74629**	GOWANUS 345.0	SR	0	0.03	IN	IN	IN	IN	IN	IN	4 (No change)
	74337	GOWANUSS 345.0	**74629**	GOWANUS 345.0	SR	0	0.03	IN	IN	IN	IN	IN	IN	

1 Should be in service for summer, winter, light-load basecases.

2 Should be in service for summer base case.

3 When Dunwoodie Interface Series reactors are out of service, Y49 and Gowanus series reactors must be in service.

4 When Dunwoodie Interface Series reactors are out of service, Y49 and Gowanus series reactors must be in service. (To bus is 74327, as against 74629). It is stated that Gowanus series reactors ‘may be’ bypassed when Dunwoodie reactors are in service. Since there is no clear requirement to take out of service (which causes convergence problems none the less), summer basecases have Gowanus reactors in service.


15055
E179 ST 138.
74435
HG TAP 138.
74631
E RIVER 69.0
74632
E13 ST 138.
74434
PAR2 345.
74329
PAR1 345.
74328
E15ST 47 345.
74324
E15ST 48 345.
74325
FARRAGUT 345.
74327
Gowanus
RAINYSW1
154
RAINEY 345.
74345
GOWANUSN 345.
74336
GOWANUSS 345.
74337
RAINYSW2
155
GOWNUS1T 138.
74477
GOWNUS2T 138.
74479
GOETH T 230.
74370
GOTHLS N 345.
74333
GOTHLS S 345.
74335
GOWNUS1R 138.
74476
GOWNUS2R 138.
74478
GOETHALS 230.
74371
GOTHLS R 345.
74334
FR KILLS 345.
74332
COGNTECH 345.
74315
GOETH 13 13.6
74774
GRENWOOD 138.
74484
LINDEN 230.
4996
W 49 ST 345.
74354
EASTVIEW 138.
74428
REACM52 345.
74568
REACM51 345.
74567
RBACBUS 345.
74349
Y49
SR
BY
E VIEW1 345.
74317
SPRBROOK 345.
74348
E VIEW3 345.
74319
E VIEW2 345.
74318
DUNWODIE 345.
74316
DUNWD SW
150
Dunwoodie
MILLWOOD 345.
74341
E VIEW4 345.
74320
PL VILLE 345.
74342
PL VILLW 345.
74343
REAC72 345.
74651
REAC71 345.
74650
PLTVILLE 13.6
74783
WOODTA 345.
74355
FISHKILL 345.
74331

A-1.60

Figure A - 1.1: Series reactor locations in the SUM powerflow (colors reflect information in Table A - 1.2**)**

Table A - 1.3: Shunt reactors and settings

	BUS NUMBER	STATION	ID	Fdr/Bus	Voltage	MVAR	Status in Original PF			Status in Study PF			Comments		Original Instructions	
							LL	SUM	WIN	LL	SUM	WIN			At Peak	Priority
1	74328	Farragut	R11	B3402	345	60	IN	IN	IN	IN	IN	IN			In	1
2	74329	Farragut	R12	C3403	345	60	IN	IN	IN	IN	IN	IN			In	1
3	74428	Eastview	R1	Bus	138	40	IN	IN	IN	IN	IN	IN			In	1
4	74428	Eastview	R2	Bus	138	40	IN	IN	IN	IN	IN	IN			In	1
5	74428	Eastview	R3	Bus	138	40	IN	IN	IN	IN	IN	IN			In	1
6	74428	Eastview	R4	Bus	138	40	IN	IN	IN	IN	IN	IN			In	1
7	74336	Gowanus N	R6	41	345	150	IN	OUT	IN	IN	OUT	IN			Out	1
8	74337	Gowanus S	R18	42	345	150	IN	OUT	IN	IN	OUT	IN			Out	1
9	74343	Pleasantville	R2	W90	345	20	IN	OUT	IN	IN	OUT	OUT			Out	2
10	74342	Pleasantville	R1	Y86	345	20	IN	OUT	IN	IN	OUT	OUT			Out	2
11	74370	Goethals	TN-1	A2253	13.8	67.5	OUT	OUT	OUT	OUT	OUT	OUT			Out	3
12	74370	Goethals	TN-2	A2253	13.8	67.5	OUT	OUT	OUT	OUT	OUT	OUT			Out	3
13	74333	Goethals N	R25	25	345	150	IN	IN	OUT	IN	IN	OUT			In	2
14	74335	Goethals S	R26	26	345	150	IN	IN	OUT	IN	IN	OUT			In	2
15	74324	Poletti	R61	Q35L	345	150	OUT	OUT	OUT	OUT	OUT	OUT			Out	2
16	74325	Poletti	R62	Q35M	345	150	OUT	OUT	OUT	OUT	OUT	OUT			Out	2
17	74316	Dunwoodie	R1	Y50	345	150	IN	IN	IN	IN	IN[4]	IN[5]			Out	2
18	74345	Rainey	1E	71	345	150	IN	IN	IN	IN	IN[6]	IN[7]			Out	2
19	74345	Rainey	5W	72	345	150	IN	IN	IN	IN	IN[8]	IN[9]			Out	2
20	74568	Sprain Brook	4S1	M52	345	150	IN	OUT	IN	IN	OUT	OUT	Changed		Out	2
21	74568	Sprain Brook	4S2	M52	345	150	IN	OUT	IN	IN	OUT	OUT			Out	2
22	74567	Sprain Brook	5S1	M51	345	150	IN	OUT	IN	IN	OUT	OUT	Changed		Out	2
23	74567	Sprain Brook	5S2	M51	345	150	IN	OUT	IN	IN	OUT	OUT			Out	2
24	74349	Sprain Brook	2N1	Y49	345	150	IN	IN	IN	IN	IN	IN			In	2
25	74349	Sprain Brook	2N2	Y49	345	150	IN	IN	IN	IN	IN	IN[10]			Out	2
26	74348	Sprain Brook	S6A	X28	345	150	IN	OUT	IN	IN	OUT	IN[11]			Out	3
27	74435	E 179th St	5W	WEST S/S	138	75	IN	OUT	IN	IN	OUT	OUT	Changed		Out	3
28	74435	E 179th St	6E	EAST S/S	138	75	IN	OUT	IN	IN	OUT	OUT			Out	3
29	74484	Greenwood	3N	42232	138	75	IN	OUT	IN	IN	OUT	OUT	Changed		Out	3

[4] In service for avoiding resonance conditions
[5] In service for avoiding resonance conditions
[6] Stuck breaker issue
[7] Stuck breaker issue
[8] Stuck breaker issue
[9] Stuck breaker issue
[10] Y49 in service - requires at least three shunt reactors
[11] Delayed tripping issue

30	74484	Greenwood	2S	42231	138	75	IN	OUT	IN	IN	OUT	OUT			Out	3

PRIORITY #

1) Shunt reactors must be in service (only System Operations can decide to switch out)

2) Shunt reactors must be in service, but may be removed as required (some risk involved).

3) Shunt reactors are in service only for area station voltage control.

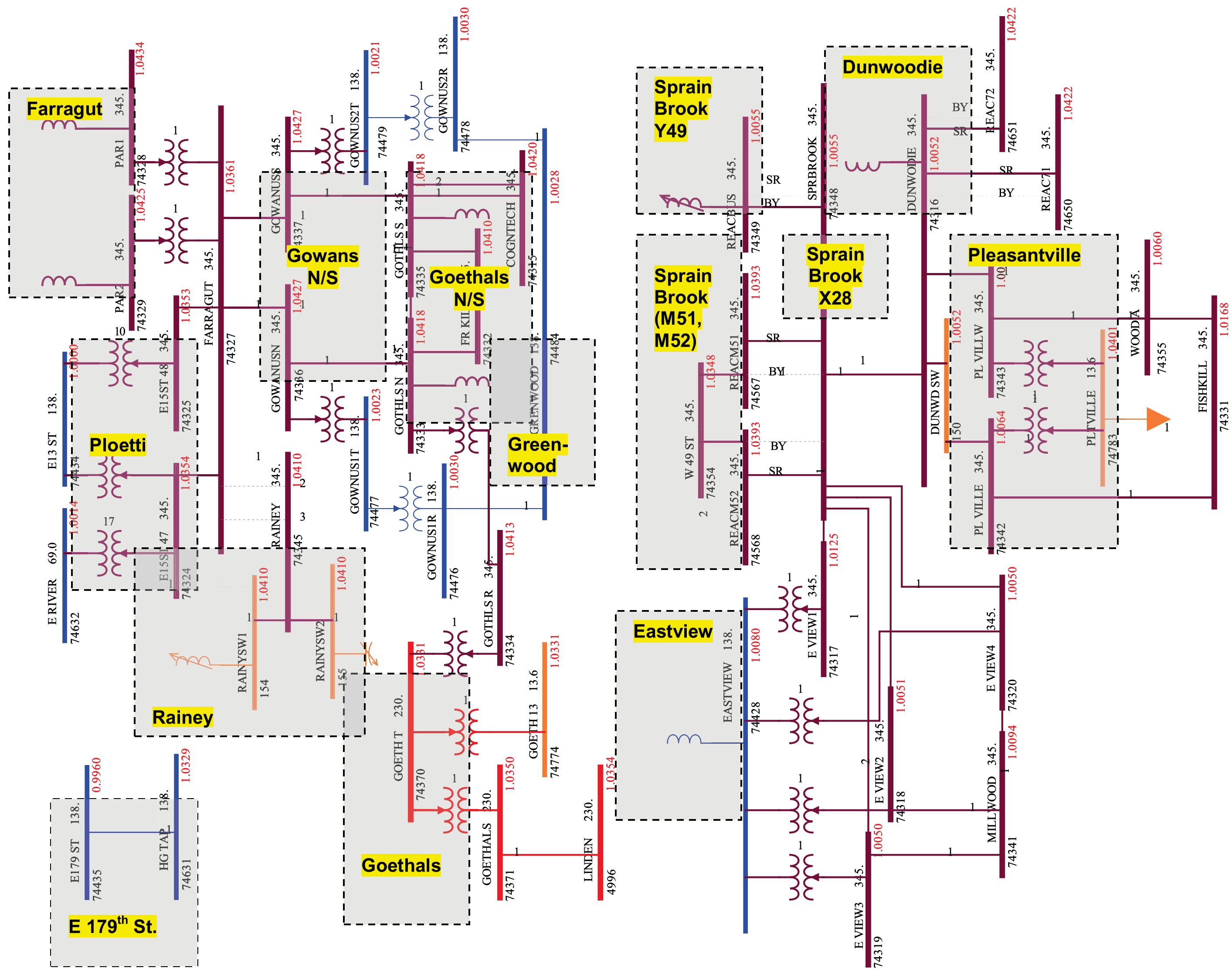


Figure A - 1.2: Shunt reactors in the SUM powerflow

Table A - 1.4: Switchable shunts and settings

Bus number	Bus name	Base kV	Area	Area name	Total B-Shunt (Mvar)	# of Cap Banks	Each Bank	Status in basecases	Action taken
74399	NEWTOWN	27	10	NYC	60	2	30	Bus not found	Checked/ not found
74404	YORK	13.6	10	NYC	20	1	20	O/S in LL	None
74509	SEAPRT#1	13.6	10	NYC	60	3	20	O/S in WIN/LL	None
74630	GATEWAY	27	10	NYC	30	1	30	Bus not found	Checked/ not found
74643	ASTOR	13.6	10	NYC	60	3	20	O/S in WIN/LL	None
74645	FRHKIL33	33	10	NYC	30	1	30	O/S in WIN/LL	None
74652	BNSHR#1	27	10	NYC	90	3	30	60 Mvar in WIN; O/S in LL	None
74653	BNSHR#2	27	10	NYC	90	3	30	60 Mvar in WIN; O/S in LL	None
74654	BRNSVL#1	27	10	NYC	90	3	30	O/S in LL	None
74655	BRNSVL#2	27	10	NYC	90	3	30	O/S in LL	None
74657	CRNA1 27	27	10	NYC	90	3	30	O/S in LL	None
74658	CRNA2 27	27	10	NYC	90	3	30	O/S in LL	None
74659	GLENDALE	27	10	NYC	90	3	30	60 Mvar in WIN; O/S in LL	None
74660	GREENW27	27	10	NYC	90	3	30	60 Mvar in WIN; O/S in LL	None
74662	JAMACA27	27	10	NYC	90	3	30	60 Mvar in WIN; O/S in LL	None
74664	NQ 27KV	27	10	NYC	90	3	30	O/S in LL	None
74668	PLYMOUTH	27	10	NYC	90	3	30	O/S in WIN/LL	None
74669	WATER ST	27	10	NYC	90	3	30	O/S in WIN/LL	None
74677	PARKVIEW	13.6	10	NYC	20	1	20	O/S in WIN/LL	None
74732	WOODROW	13.6	10	NYC	40	2	20	O/S in LL	None
74738	BUCHAN	13.6	8	MILLWOOD	40	2	20	O/S in WIN/LL	None
74739	CEDAR ST	13.6	9	DUNWOODI	40	2	20	O/S in WIN/LL	None
74741	ELMSFD#2	13.6	9	DUNWOODI	60	3	20	O/S in WIN/LL	None
74743	GRANTHIL	13.6	9	DUNWOODI	60	3	20	O/S in WIN/LL	None
74744	HARRSON	13.6	9	DUNWOODI	60	3	20	O/S in WIN/LL	None
74745	MILWD W	13.6	8	MILLWOOD	20	1	20	I/S all PF	Voltage ok in LL, Not changed
74746	OSS W 13	13.6	8	MILLWOOD	20	1	20	I/S all PF	Voltage ok in LL, Not changed

74748	WH PLNS	13.6	9	DUNWOODI	60	3	20	20 Mvar in WIN; O/S in LL	None
74751	WSHNTNST	13.6	9	DUNWOODI	40	2	20	I/S all PF	Voltage ok in LL, Not changed
74752	W42ST#1	13.6	10	NYC	60	3	20	O/S in LL	None
74753	W42ST#2	13.6	10	NYC	60	3	20	O/S in LL	None
74754	W65ST#1	13.6	10	NYC	40	2	20	O/S in LL	None
74755	W65ST#2	13.6	10	NYC	40	2	20	O/S in LL	None
74765	AVENUEA	13.6	10	NYC	60	3	20	40 Mvar in WIN; O/S in LL	None
74766	BRCKNR13	13.6	10	NYC	60	3	20	O/S in LL	None
74767	CHERY ST	13.6	10	NYC	40	2	20	O/S in LL	None
74769	E179ST13	13.6	10	NYC	60	3	20	O/S in LL	None
74770	E29ST	13.6	10	NYC	60	3	20	O/S in LL	None
74771	E63RD#1	13.6	10	NYC	40	2	20	O/S in WIN/LL	None
74772	E63RD#2	13.6	10	NYC	40	2	20	O/S in WIN/LL	None
74773	E75TH ST	13.6	10	NYC	60	3	20	O/S in WIN/LL	None
74779	HELLGATE	13.6	10	NYC	80	4	20	O/S in LL	None
74780	HELLGT13	13.6	10	NYC	80	4	20	Bus O/S in all PF	Not changed
74781	LENRDST1	13.6	10	NYC	40	2	20	O/S in LL	None
74782	LENRDST2	13.6	10	NYC	40	2	20	O/S in LL	None
74783	PLTVILLE	13.6	9	DUNWOODI	40	2	20	O/S in WIN/LL	None
74784	PRKCHT#1	13.6	10	NYC	60	3	20	O/S in LL	None
74785	PRKCHT#2	13.6	10	NYC	60	3	20	40 Mvar in SUM; O/S in LL	Voltage ok in SUM, 60 Mvar I/S
74790	SEAPRT#2	13.6	10	NYC	60	3	20	40 Mvar in WIN; O/S in LL	None
74791	SHCK13KV	13.6	10	NYC	80	4	20	O/S in LL	None
74792	TRADCTR1	13.6	10	NYC	60	3	20	O/S in LL	None
74794	WAINRT13	13.6	10	NYC	40	2	20	20 Mvar in WIN; O/S in LL	None
74795	WILOWBRK	13.6	10	NYC	40	2	20	O/S in LL	None
74800	W110ST#1	13.6	10	NYC	60	3	20	O/S in WIN/LL	None
74801	W110ST#2	13.6	10	NYC	60	3	20	O/S in WIN/LL	None
74802	W19TH ST	13.6	10	NYC	60	3	20	O/S in LL	None
74803	W50TH ST	13.6	10	NYC	60	3	20	O/S in LL	None
74804	E36ST	13.6	10	NYC	60	3	20	O/S in LL	None
74805	E40ST#1	13.6	10	NYC	60	3	20	O/S in WIN/LL	None
74806	E40ST#2	13.6	10	NYC	60	3	20	O/S in WIN/LL	None
74808	MURAYHIL	13.6	10	NYC	40	2	20	20 Mvar in WIN; O/S in LL	none

Section A-2: Powerflow Base Case Modifications

General principles for conducting corrective actions on the powerflow basecases:

- Primarily focus on apparent inconsistencies outside of NY area (area 1-11) and do the necessary changes
- Provide careful attention in making changes within the NY area

Table A - 2.1: Format of reporting the modifications

Serial No	***Base case file time tag***	***Short description***
Problem & solution		
Relevant areas		

Chronological changes in the SUMMER powerflow base case:

Table A - 2.2: Modification # 0 (SUM)

0	***April 23 [8 47pm]***	***HVDC & 3W transformer data***
Convergence problems noticed due to small HVDC line resistance and three winding transformer impedance		
HVDC: WAPA, WECC; 3W transformer: OKGE		

Table A - 2.3: HVDC line resistance changes

From	To	ID	Original value	New Value
REC09	INV09	1	0	0.1
REC41	INV41	1	0	0.1
REC42	INV42	1	0	0.1
REC43	INV43	1	0	0.1
REC46	INV46	1	0	0.1
REC47	INV47	1	0	0.1

Table A - 2.4: Three winding transformer impedance changes

Buses	Winding	ID	Original value	New Value
55233;55234;55750	Secondary	1	6.0007e-005	0.0060007
13073;13151;13692	Tertiary	1	-5.00027e-006	-0.005

Table A - 2.5: Modification # 1 (SUM)

1	***May 27 [4 23pm]***	***HVDC model control***
Change AT control to AL/GA control for Rec/Inv (especially for # 29)		
LI+JCPL, HQ, MP, WAPA areas		

Table A - 2.6: List of changes in HVDC control

DC Bus 1		AC Bus Number		AC Bus Name		Controlled Variable 2		
1	**2**	**1**	**2**	**1**	**2**	**1**	**2**	**Diff**
REC03	REC03	66756	66756	SQBUTTE4 230.	SQBUTTE4 230.	AT	AL	Diff
INV03	INV03	61615	61615	ARROWHD4 230.	ARROWHD4 230.	AT	GA	Diff
REC04	REC04	66756	66756	SQBUTTE4 230.	SQBUTTE4 230.	AT	AL	Diff
INV04	INV04	61615	61615	ARROWHD4 230.	ARROWHD4 230.	AT	GA	Diff
INV09	INV09	66402	66402	MI CTYW4 230.	MI CTYW4 230.	AT	GA	Diff
REC11	REC11	84419	84419	CHAT G 315.	CHAT G 315.	AT	AL	Diff
INV11	INV11	85319	85319	CHAT G3 120.	CHAT G3 120.	AT	GA	Diff
REC29	REC29	2872	2872	RAR RVR 230.	RAR RVR 230.	AT	AL	Diff
INV29	INV29	74959	74959	NEPTCONV 345.	NEPTCONV 345.	AT	GA	Diff

Table A - 2.7: Modification # 2 (SUM)

2	*May 27 [4 23pm]*	*Relax shunt control*
Lower and upper voltage limits of three shunts are too close, imposes difficulty in convergence, hence upper limit is increased.		
HUDSON, CENTRAL		

Table A - 2.8: List of shunt control modifications

Bus Number			**Bus Name**		**Terminal Voltage Upper Limit**		
1	**2**		**1**	**2**	**1**	**2**	**Diff**
74115	74115		N.BALT 69.0	N.BALT 69.0	1.0220	1.0400	-0.0180
74126	74126		SAUGERT 69.0	SAUGERT 69.0	1.0220	1.0400	-0.0180
75561	75561		CNDGUA34 34.5	CNDGUA34 34.5	1.0100	1.0400	-0.0300

Table A - 2.9: Modification # 3 (SUM)

3	*June 4 (a) [9.49 am]*	*Cut load*
Small loads with high line impedance were causing voltage collapse and were appearing in the modal analysis. Therefore, these were removed.		
MOHAWK [76465 - 78585] Cut load (1 MW/ 0. 5 MVAR) & shunts (0.3 MVAr)		

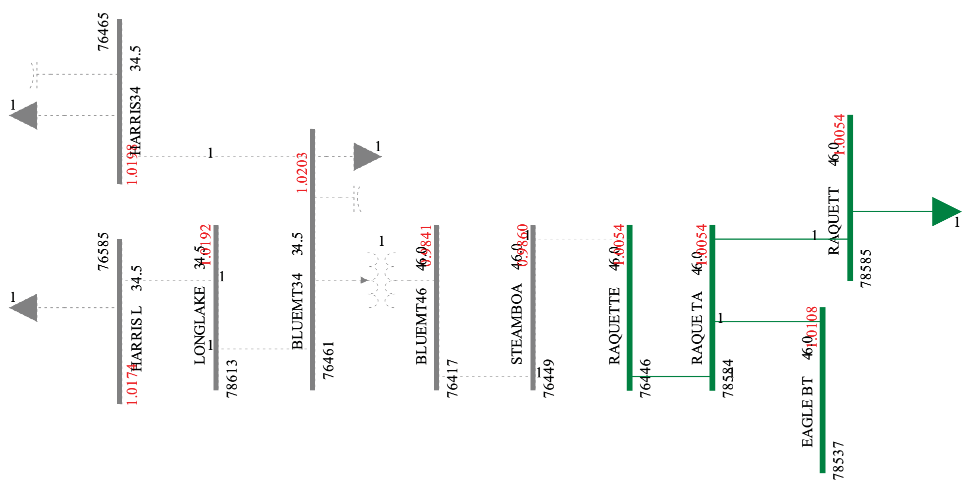


Figure A - 2.1: Modification # 3 (SUM)

Table A - 2.10: Modification # 4 (SUM)

4	*June 4 (b) [5 18 pm]*	*Cut load, tap setting*
Small loads with high line impedance were causing voltage collapse and were appearing in the modal analysis. Therefore, these were removed.		
GENESEE [79851, 79799, 79999]- Cut load (~15 MW/8 MVAr) MOHAWK [79630, 76369] – Cut load (~ 5 MW/ 2 MVAr) MOHAWK [78585] – Cut load & lines (1 MW/0.5 MVAr) IESO [82860]- Transformer tap reduced (0.96 to 0.94)		

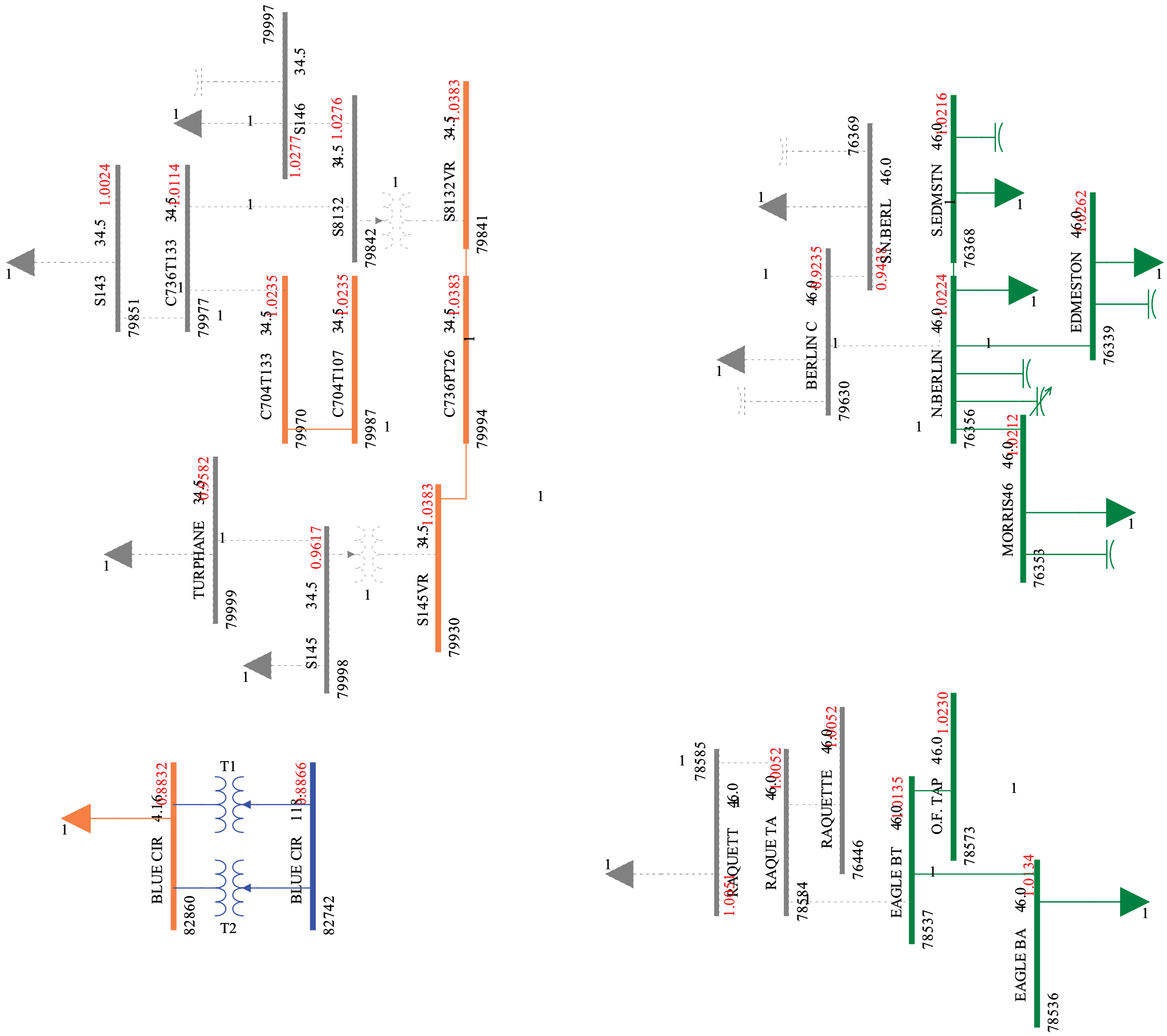


Figure A - 2.2: Modification # 4 (SUM)

Table A - 2.11: Modification # 5 (SUM)

5	*June 5 (a) [11 40 am]*	*Increase MVAr limit*
Large units in the TVA area are showing up in the modal analysis due to limits on their reactive power.		
TVA [18135,18136,18137] – MVAr limit increased to 220 MVAr		

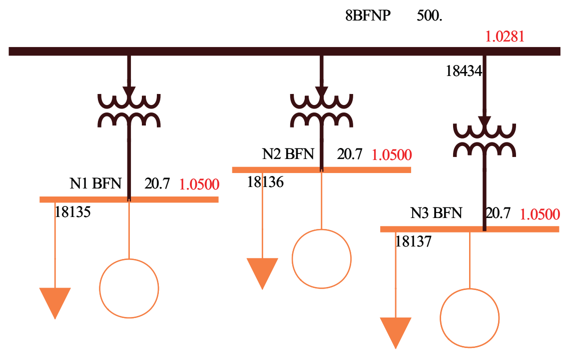


Figure A - 2.3: Modification # 5 (SUM)

Table A - 2.12: Modification # 6 (SUM)

6	*June 5 (b) [11 40 am]*	*Cut load*
Local modes showing up in other modal analysis		
MILLWOOD [75771,75779,75802] – Load cut (~ 7 MW/3.5 MVAr) & Shunt outage (~1.5 MVAr) CENTRAL [79650] – Load cut (~ 10MW/ 5 MVAr) & shunt outage (~3 MVAr)		

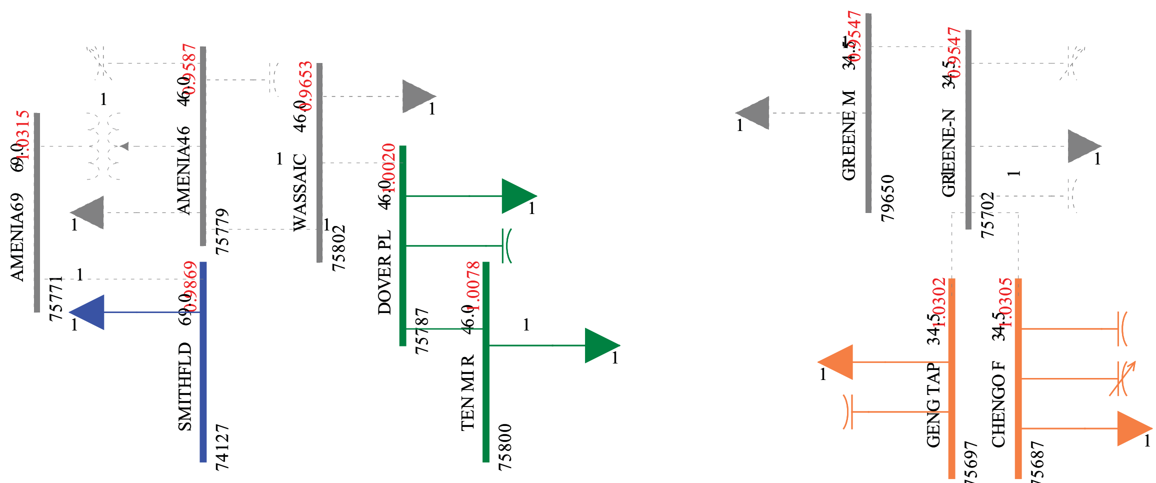


Figure A - 2.4: Modification # 6 (SUM)

Table A - 2.13: Modification # 7 (SUM)

7	*June 8 (a) [11 01 am]*	*Shunt voltage limit*
Shunt switches on/off and creates convergence problem.		
IESO [82875] – Lower limit increased from 0.9 to 1.01		

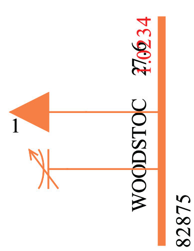


Figure A - 2.5: Modification # 7 (SUM)

Table A - 2.14: Modification # 8 (SUM)

8	*June 8 (b) [12 04 am]*	*Load model change*
Apparent load model issue		
DUNWOODI [74743, 74744] - Constant current load reduced by ~20 MW/10 MVAr		

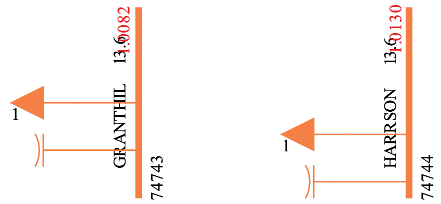


Figure A - 2.6: Modification # 8 (SUM)

Table A - 2.15: Modification # 9 (SUM)

9	*June 8 (c) [1 24 pm]*	*Switchable shunt lower limit*
Shunt voltage lower limit increased from 0.9373 to 1.02		
IESO [82505]		

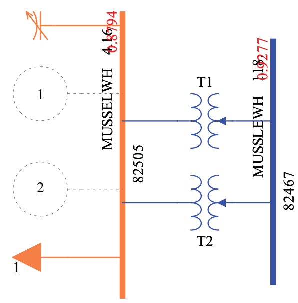


Figure A - 2.7: Modification # 9 (SUM)

Table A - 2.16: Modification # 10 (SUM)

10	*June 9 [3 29 pm]*	*Generator control settings& others*
Control inconsistency (two units controlling the remote 500 kV bus) removed and MVAr limit further increased to 300 MVAr. The lower limit of the shunt at 82875 is further increased to 1.025 Line impedance 87890-87956 appeared to be low and was causing powerflow convergence problems.		
TVA [18135 & 18136] – control adjustment IESO [82875] – voltage limit NB [87980- 87956] – line impedance (0.001-0.005)		

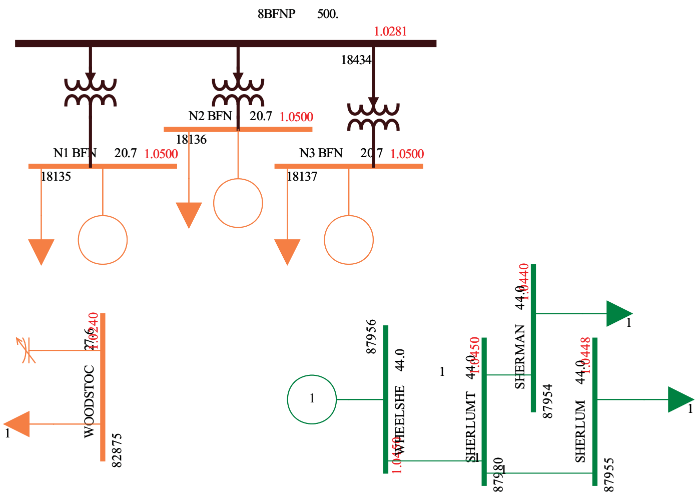
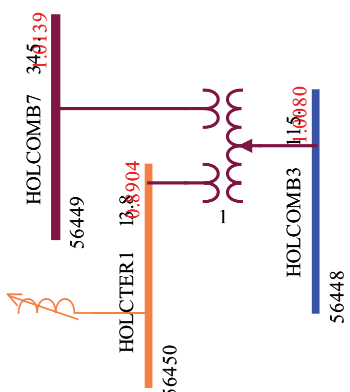
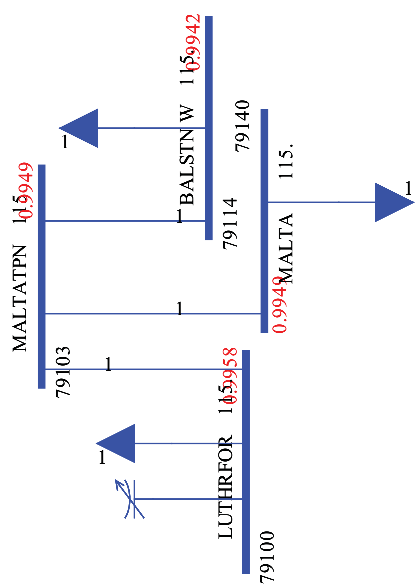


Figure A - 2.8: Modification # 10 (SUM)

Table A - 2.17: Modification # 11 (SUM)

11	*June 14 [5 28 pm]*	*Impedance, SVC (correction)*
Inconsistency in transformer impedance & line impedance appeared to have caused powerflow convergence problems. SVC bus inaccuracy corrected (Load bus to Generator bus)		
SUNC [56450] – Negative impedance in one winding is converted to positive. CAPITAL [79103 - 79140] – Line impedance made to 0.0009 (from 0.0003) MOHAWK [79799] – Bus changed from Load bus to Generator bus		





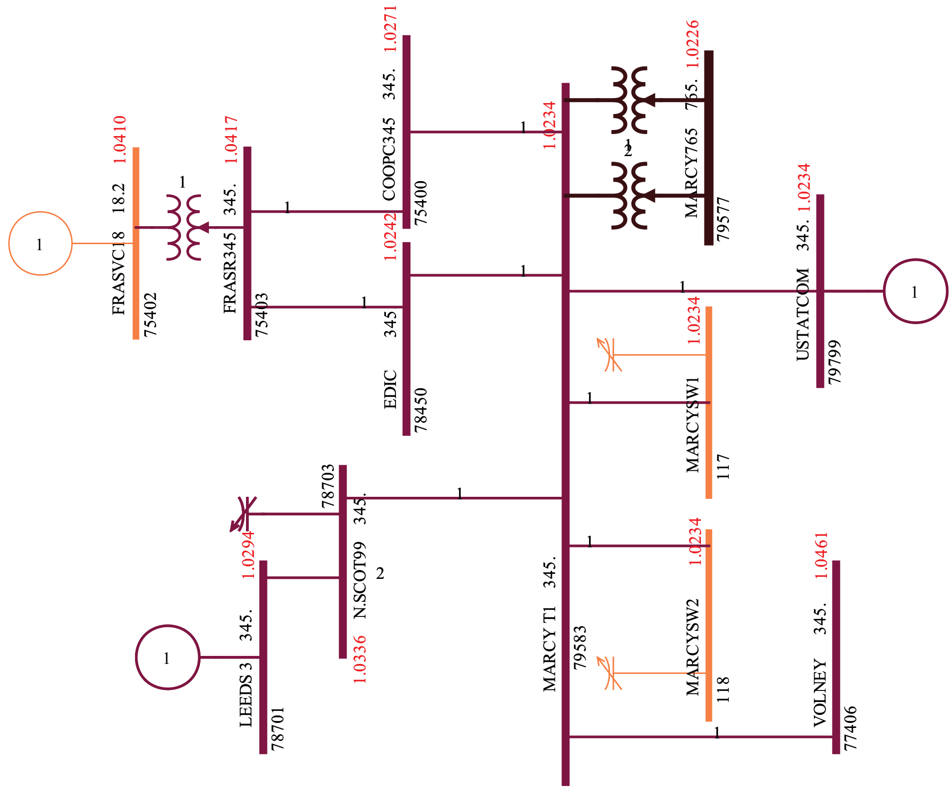


Figure A - 2.9: Modification # 11 (SUM)

Table A - 2.18: Modification # 12 (SUM)

12	***June 16 [3 35 pm]***	***Cut load, freeze ULTC, correct impedance, remove small load/generators***
IESO, NI areas showing up in modal analysis due to inconsistency in transformer impedance, line impedance, ULTC + switchable shunt control action mismatch		
IESO [82838] – Load cut (~5 MW/2MVAr) IESO [82875] – Load cut (~ 60 MW/ 30 MVAr) + ULTC frozen NI [37231] – Negative impedance changed to positive CAPITAL [79274] – Several small units (~1.5 MVA) and loads cut (~ 5 MW/1.5MVAr) MOHAWK [76446] – More lines taken out to eliminate possible mixed mode		

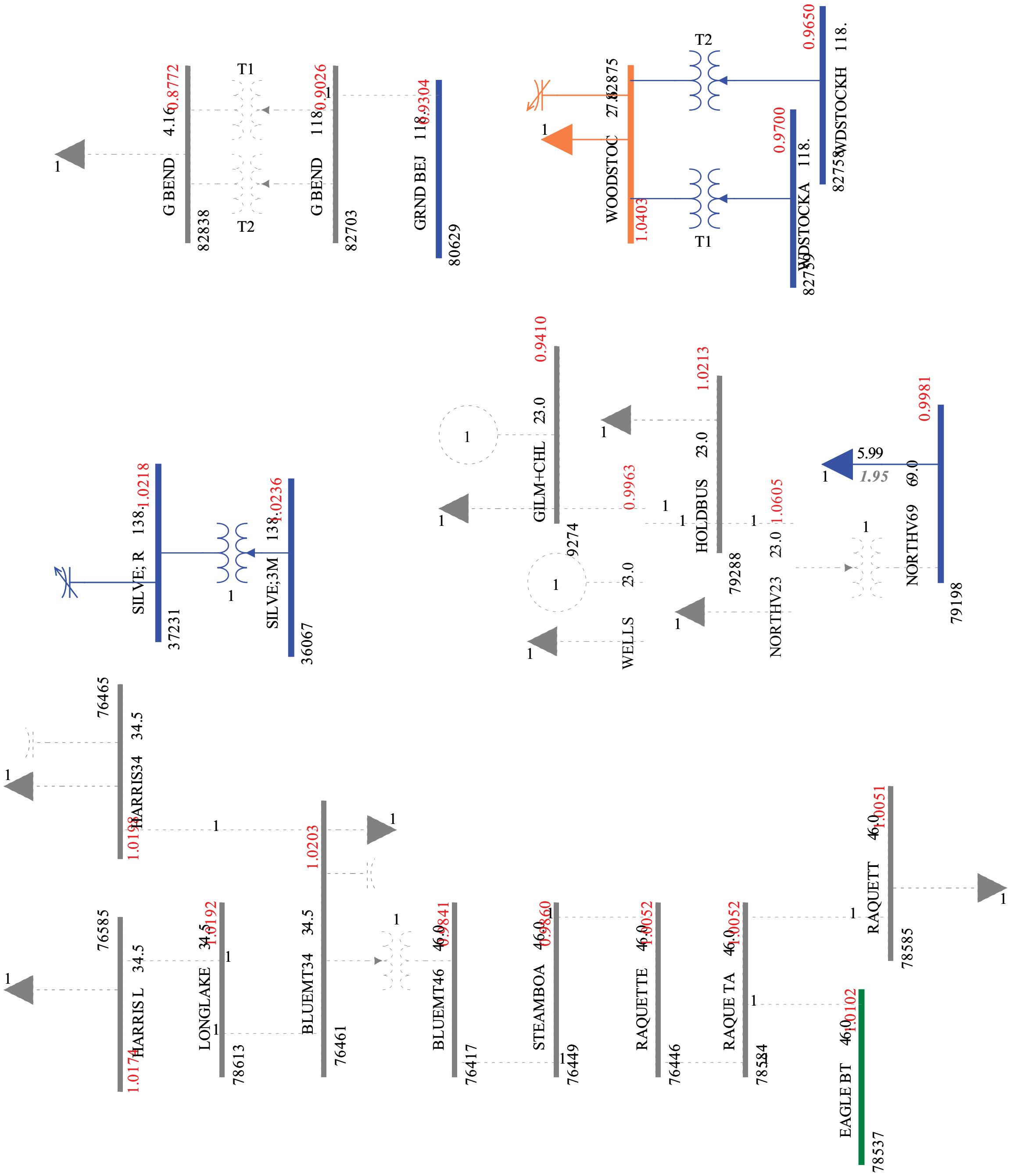


Figure A - 2.10: Modification # 12 (SUM)

Table A - 2.19: Modification # 13 (SUM)

13	*June 17 [3 11 pm]*	*Cut load, Increase MVAr limit*
Load cut to eliminate possible local mixed/erroneous mode (CENTRAL mixed with GENESSE) TVA units' MVAr limit further increased		
CENTRAL [79648] – Load cut (44 MW/ 21 MVAr to 38 MW/18 MVAr , ie, ~6 MW/3MVAr) TVA [18135] – MVAr limit further increased to 500 MVAr		

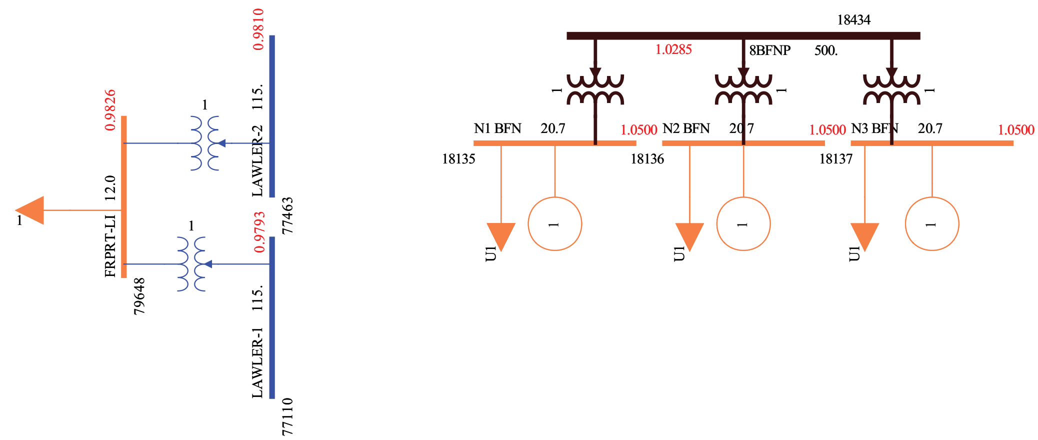


Figure A - 2.11: Modification # 13 (SUM)

Table A - 2.20: Modification # 14 (SUM)

14	*June 18 [2.53 pm]*	*Cut load, change shunt settings*
IESO and other remote areas showing up in the modal analysis		
IESO [83604, 82864, 82868] – Switchable shunt lower voltage limit increased from 0.9 to 1.025 IESO [82860,80161,80645] – Load cut (~12/6 MW/MVAr, ~3 MW/1.5 MVAr, ~3 MW/1.5 MVAr) PENELEC [416] – Load cut (~6 MW/2MVAr) XEL [61231] – High impedance line (> 1 p.u.) with small load (<1MW/1MVAr) cut WEC [39022] – Small unit (~1 MVA) with high impedance transformer (>2 p.u.) taken out JCPL [2846] – Load cut (~6 MW/3MVAr)		

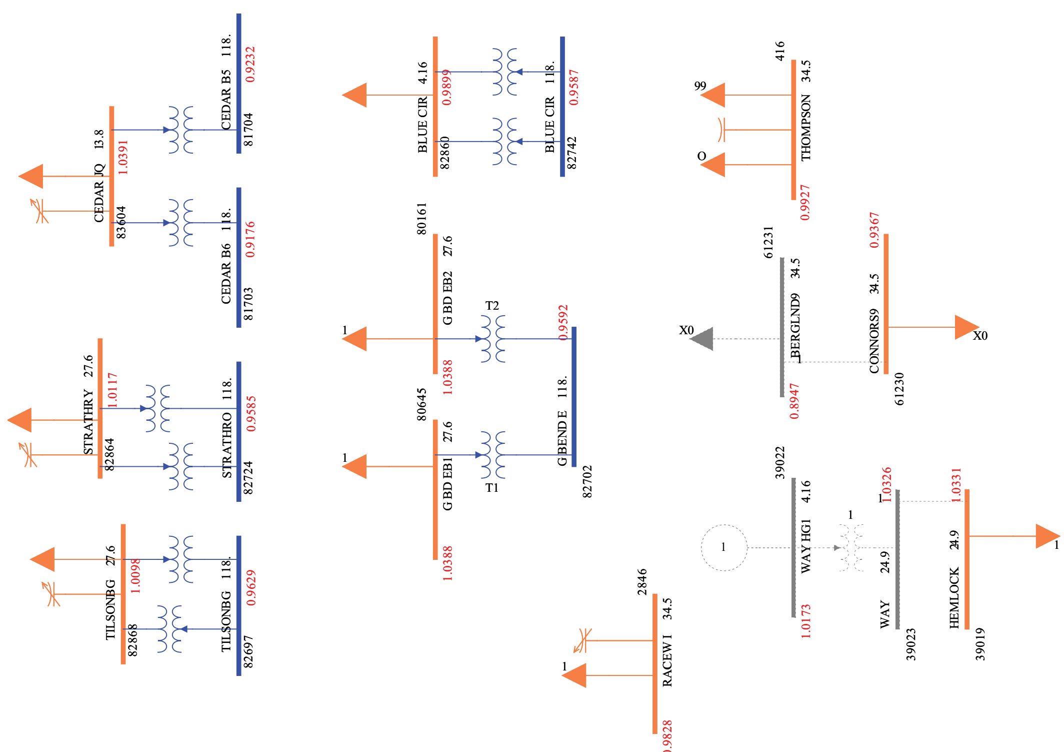


Figure A - 2.12: Modification # 14 (SUM)

Table A - 2.21: Modification # 15 (SUM)

15	*June 24 [11 07 am]*	*Cut load*
Localized voltage instability showing up in other modes.		

GENESEE [77273 to 77166] – Cut small loads (~ 4 MW & 0.5 MVAr)

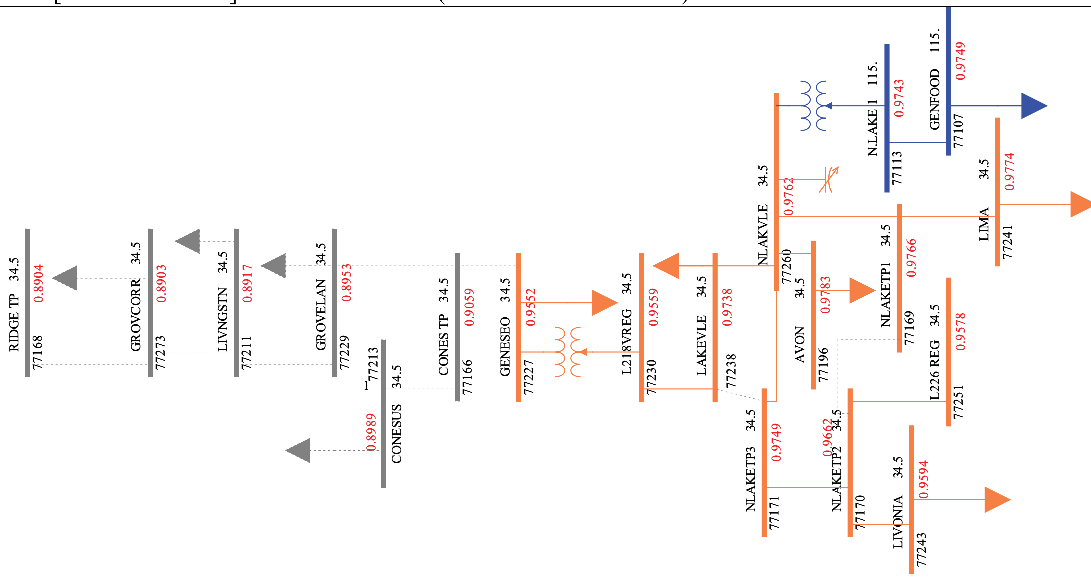


Figure A - 2.13: Modification # 15 (SUM)

Table A - 2.22: Modification # 16 (SUM)

16	***June 30 (a) [3 11 pm]***	***Cut load, Increase MVAr limit***
TVA units' MVAr limit further increased		
TVA [18135] – MVAr limit further increased to 600 MVAr		

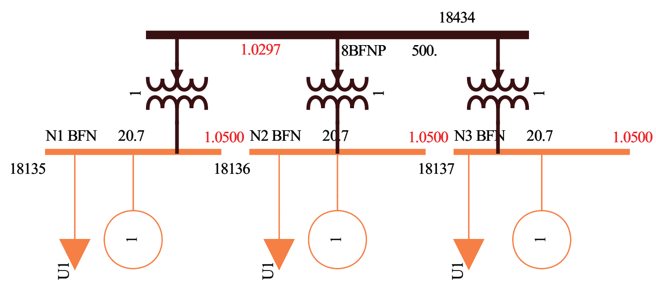


Figure A - 2.14: Modification # 16 (SUM)

Table A - 2.23: Modification # 17 (SUM)

8	***June 30 (b) [5 22 pm]***	***Load model change***
Load model issue apparently is resolved and previous load reduction is undone.		
DUNWOODI [74743, 74744]		

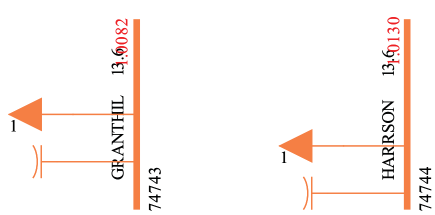


Figure A - 2.15: Modification # 17 (SUM)

Chronological changes in the WINTER powerflow base case:

Table A - 2.24: Modification # 0 (WIN)

0	*April 23 [9 44pm]*	*HVDC & 3W transformer data*
Convergence problems noticed due to small HVDC line resistance and three winding transformer impedance		
HVDC: WAPA, WECC; 3W transformer: OKGE		

Table A - 2.25: HVDC line resistance changes

From	To	ID	Original value	New Value
REC09	INV09	1	0	0.1
REC41	INV41	1	0	0.1
REC42	INV42	1	0	0.1
REC43	INV43	1	0	0.1
REC46	INV46	1	0	0.1
REC47	INV47	1	0	0.1

Table A - 2.26: Three winding transformer impedance changes

Buses	Winding	ID	Original value	New Value
55233;55234;55750	Secondary	1	6.0007e-005	0.0060007
13073;13151;13692	Tertiary	1	-5.00027e-006	-0.005

Note: Additional changes similar to Modification # 4 (SUM) are also made.

Chronological changes in the LIGHT-LOAD powerflow base case:

Table A - 2.27: Modification # 0 (LL)

0	*April 23 [8 55pm]*	*HVDC & 3W transformer data*
Convergence problems noticed due to small HVDC line resistance and three winding transformer impedance		
HVDC: WAPA, WECC; 3W transformer: OKGE		

Table A - 2.28: HVDC line resistance changes

From	To	ID	Original value	New Value
REC09	INV09	1	0	0.1
REC41	INV41	1	0	0.1
REC42	INV42	1	0	0.1
REC43	INV43	1	0	0.1
REC46	INV46	1	0	0.1
REC47	INV47	1	0	0.1

Table A - 2.29: Three winding transformer impedance changes

Buses	Winding	ID	Original value	New Value
55233;55234;55750	Secondary	1	6.0007e-005	0.0060007
13073;13151;13692	Tertiary	1	-5.00027e-006	-0.005

Table A - 2.30: Modification # 1 (LL)

1	*July 2 [1 39pm]*	*Shunt control*
Convergence problems (powerflow solution is unstable, diverges at 3rd iteration). Multiple shunts in the IESO area are frozen (originally continuous control was used)		
IESO		

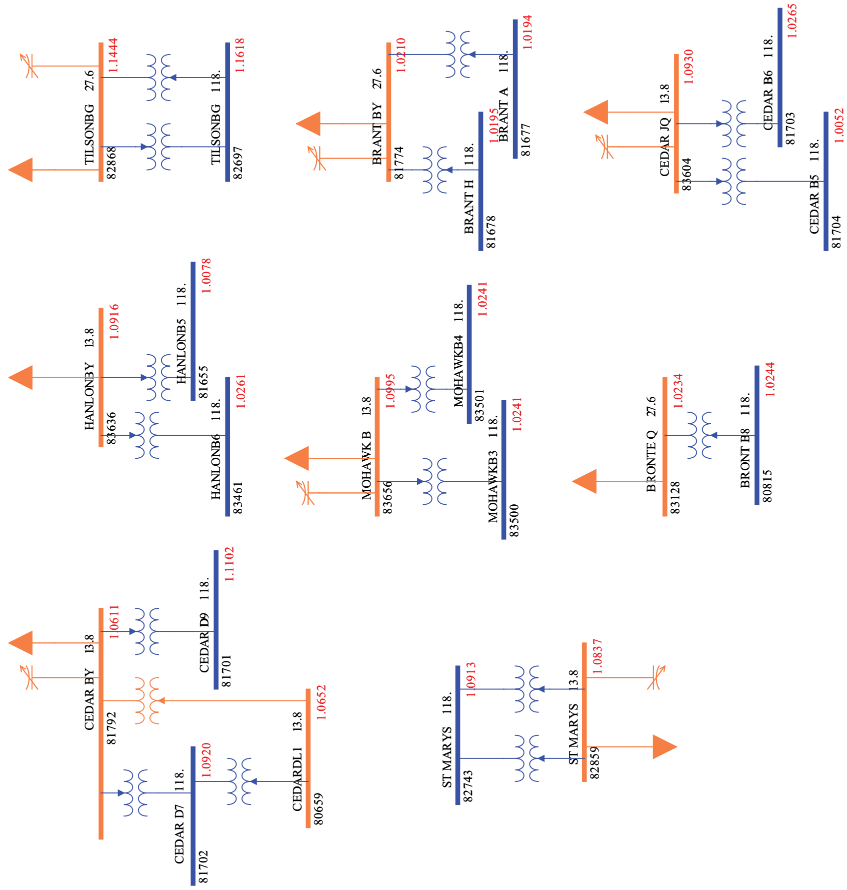


Figure A - 2.16: Modification # 1 (LL)

Table A - 2.31: Modification # 2 (LL)

1	***July 23***	***Line impedance***
Several line impedances were identified as causes for inconsistent modal report. Line impedance from 74099- 79336 increased to 0.005 (originally 0.001) and from 87980 to 87980 to 0.005 (originally 0.001)		
HUDSON, NB		

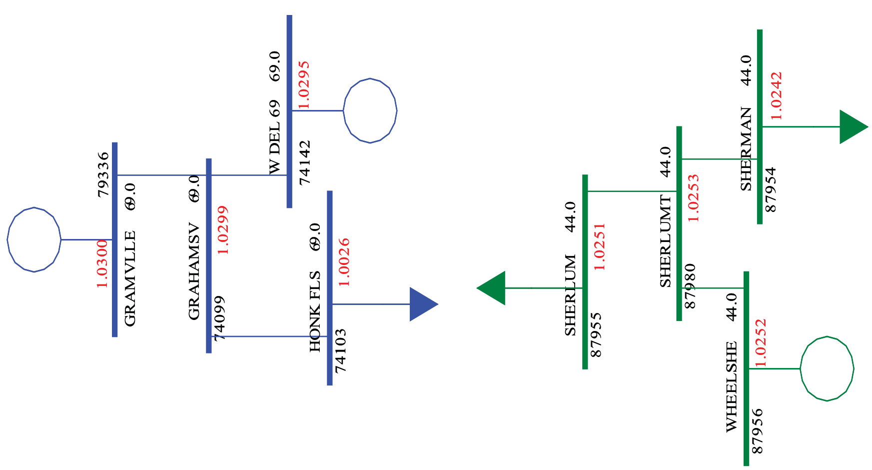


Figure A - 2.17: Modification # 2 (LL)

Note: Additional changes similar to Modification # 4 (SUM) are also made.

Section A-3: VCA Identification Program Description

Based on the process and VCA identification technique described in the previous chapters, a database in Microsoft Access 2007 was designed and an interface program was developed for VCA identification. The VCA identification is performed in a separate program developed in C++. The Access 2007 interface program can export, from database, the results of modal analysis for different scenarios and contingencies for the VCA identification program. The VCA identification interface uses the following modules:

- VSAT engine to perform modal analysis
- VCA identification program, clustering technique to identify VCA buses and controlling generators
- Linear Programming for reactive reserve allocation and requirement

The installation and operation of the interface program is described below.

VCA Identification Program Installation

The VCA program does not have an installation module. All of the necessary files and executables are archived in a zipped file named VCA.zip. To install the program following the steps below:

1) Make sure you have Access 2007 installed on your system
2) Create a folder for VCA program (i.e. C \VCA)
3) Copy the archived file VCA.zip into \VCA folder (this is just to have a backup of the program in the \VCA folder)
4) Unzip the VCA.zip into \VCA
5) The files listed in this folder should be as follows:

- DFORRT.DLL
- lp4vca.exe
- RunVCA.bat
- VBgetPsf.dll
- VCA.mdb
- VCA.mdw
- vca_identification.exe
- VSAT_batch.exe

Running VCA Identification Program

To use the VCA interface program, the users should have MS Access 2007 installed on their system. To start the VCA program run RunVCA.BAT and the main menu of the program will appear as shown in Figure A - 3.1.figure below:

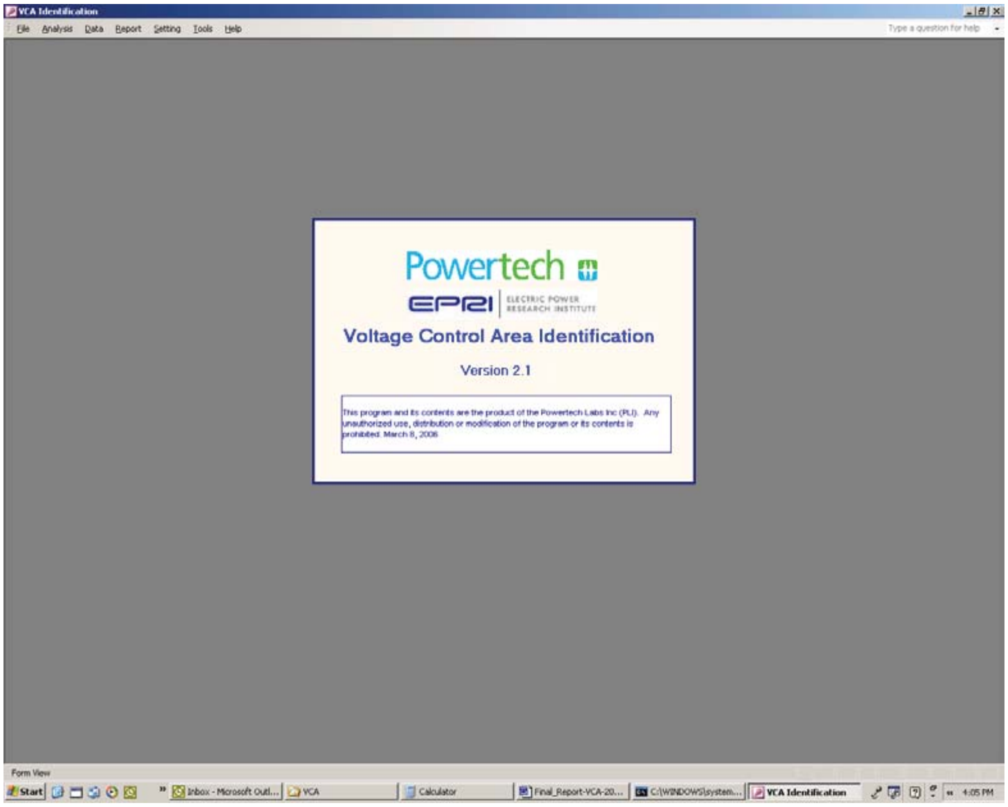


Figure A - 3.2: VCA Identification Program Main Menu

There are several menu items in the main menu of the program, namely, "File", "Analysis", "Data", "Report", "Setting", "Tools", and "Help". Each menu item may have several sub-menu items as described below.

FILE

The sub-menu items under the "File" option are shown in Figure A - 3.3. The only submenu item in this option allows the user to exit the program.

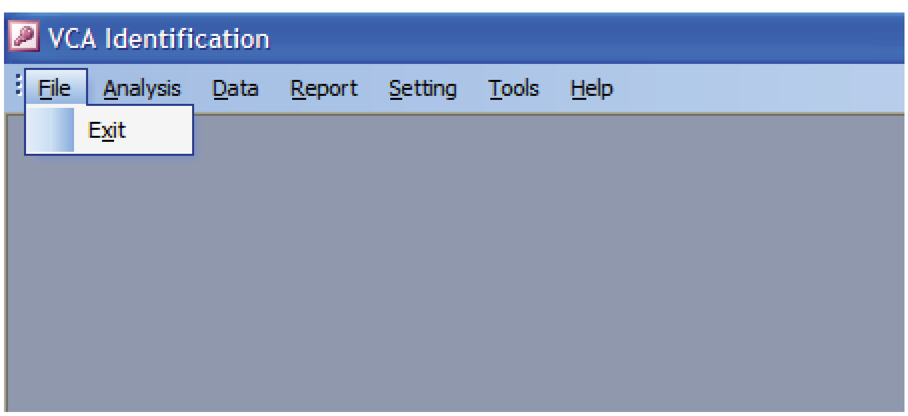


Figure A - 3.3: VCA Identification Program Interface "File" Menu Items

ANALYSIS

The sub-menu items under “Analysis” are shown in Figure A - 3.4. The following is a short description for each option:

VSAT Modal: Running modal analysis and importing (loading) results generated by VSAT program. It is possible to populate the database with the result of one simulation run and/or thousands of scenarios/contingencies.

VCA Identification: Identification of Voltage Control Areas for selected cases based on the procedure previously described and parameters defined in “Setting VCA Parameters”.

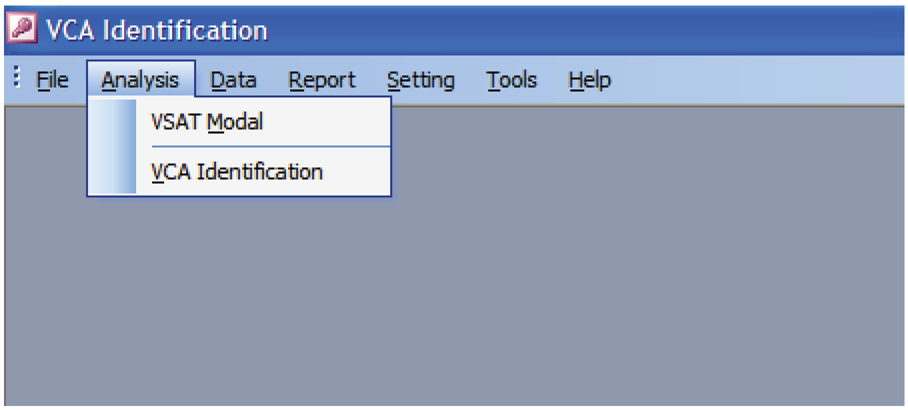


Figure A - 3.4: VCA Identification Program Interface “Analysis” Menu Items

DATA

The sub-menu items under “**Data**” are shown in Figure A - 3.5. The following is a short description for each option:

VSAT Output / Input: View a complete VSAT input and output set of data for considered scenarios.

Bus Participation Factors: View computed bus participation factors for all considered scenarios.

Eigen Values: View computed eigen values for all considered scenarios.

Delete Data: Database records can be selectively or entirely deleted.

Import Database: Import data from a previous database.

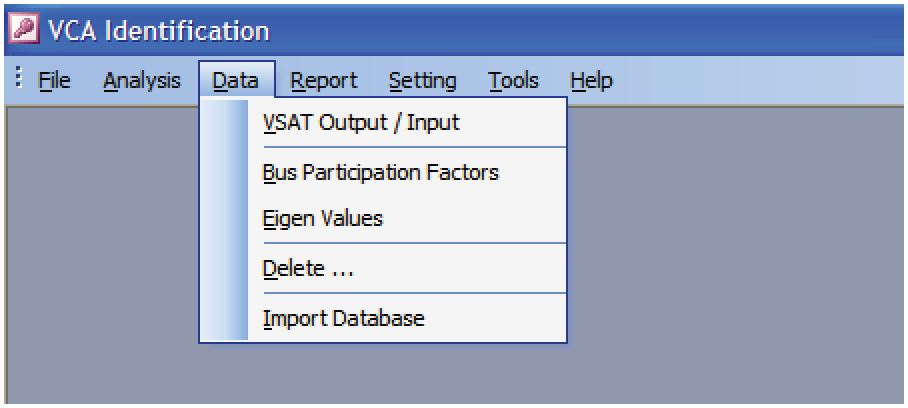


Figure A - 3.5: VCA Identification Program Interface "Data" Menu Items

REPORT

The sub-menu items under "**Report**" are shown in Figure A - 3.6. The following is a short description for each option:

VCA Results: Results of VCA identification can be viewed and examined.

Probable Local Modes: View and examine the list of probable local modes.

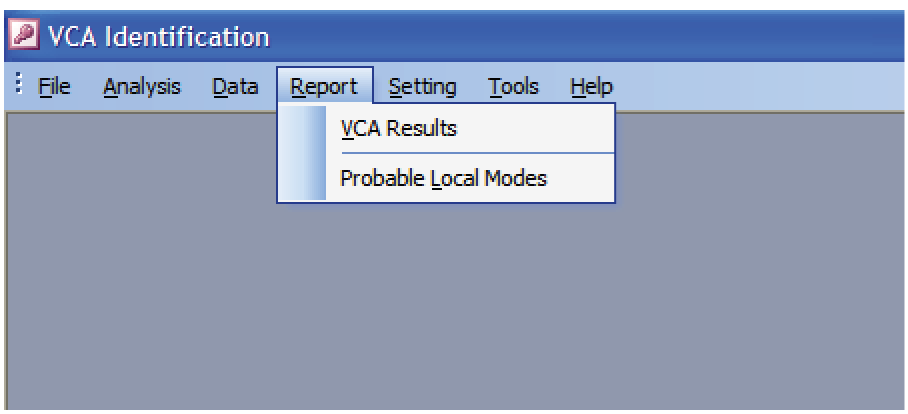


Figure A - 3.6: VCA Identification Program Interface "Report" Menu Items

SETTING

The program parameters can be set by selecting "Setting" sub-menu items as shown in Figure A - 3.7.

Version: Setting current version of the database.

Required Margin: Setting required margin for VCA reactive power requirement determination.

VCA Parameters: Setting parameters for VCA identification.

Excluded Generators: Excluding generators from the VCA analysis based on their ratings.

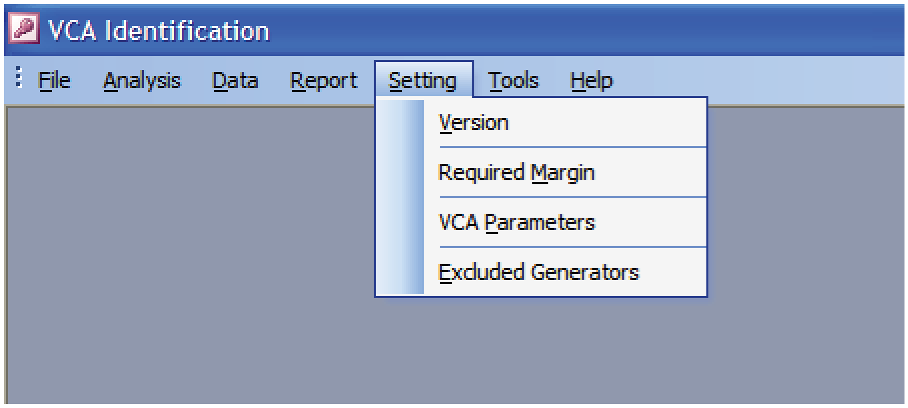


Figure A - 3.7: VCA Identification Program Interface "Setting" Menu Items

TOOLS

The sub-menu items under the "Tools" option are shown in Figure A - 3.8. The only submenu item in this option allows the user to compact and repair the database.

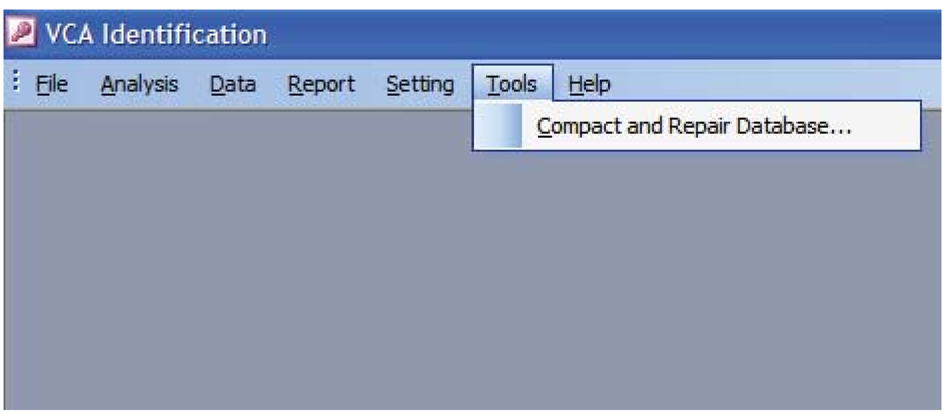


Figure A - 3.8: VCA Identification Program Interface "Tools" Menu Items

HELP

The sub-menu items under the "Help" option are shown in Figure A - 3.9. The only submenu item in this option allows the user to get help on Access.

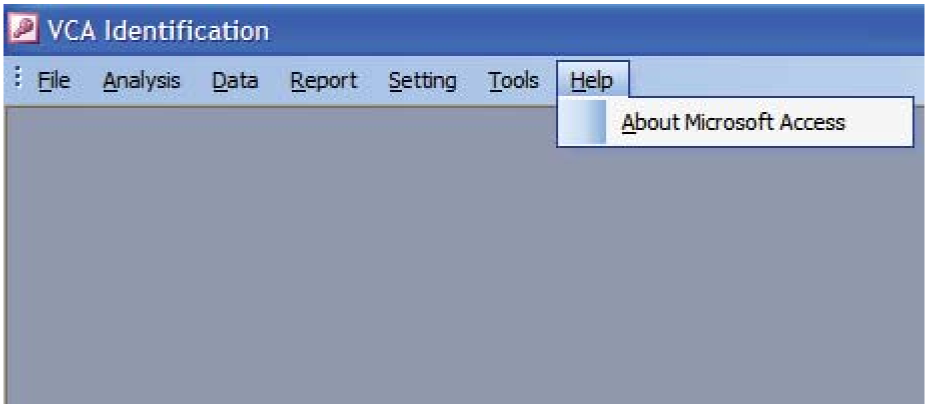


Figure A - 3.9: VCA Identification Program Interface "Help" Menu Items

VCA Identification Program Tutorial

The following steps are necessary in order to run VCA Identification Program:

a. Preparation of VSAT Scenarios
b. Deleting Record(s) from VCA Database if previously analyzed scenarios are not needed
c. Setting Parameters for VSAT Modal Analysis
d. Running VSAT Modal Analysis and Importing Results Into VCA Database
e. Examining Probable Local Modes
f. Setting Parameters for VCA Identification
g. Running VCA Identification
h. Examining VCA Identification Results

The following options are available for users' convenience:

i. Examining VSAT Output/Input Data
j. Examining Results of Modal Analysis
k. Importing Previous Database
l. Setting Program Version
m. Compacting and Repairing Database

a. Preparation of VSAT Scenarios

Some basic familiarity with VSAT is necessary to prepare the scenarios to be run with the VCA Identification Program. For more information on how to prepare the scenarios, user should consult VSAT User Manual.

b. Deleting Record(s) from VCA Database

If a new case is to be started, the database (vca.mdb) needs to be saved under a different name (e.g. vca_old.mdb), and all records deleted prior to starting the new VCA identification analysis. To delete record(s) from the VCA database, select "Data" -> "Delete" as shown in Figure A - 3.5. The delete data screen allows the user to selectively or entirely delete the database records as shown in Figure A - 3.10.

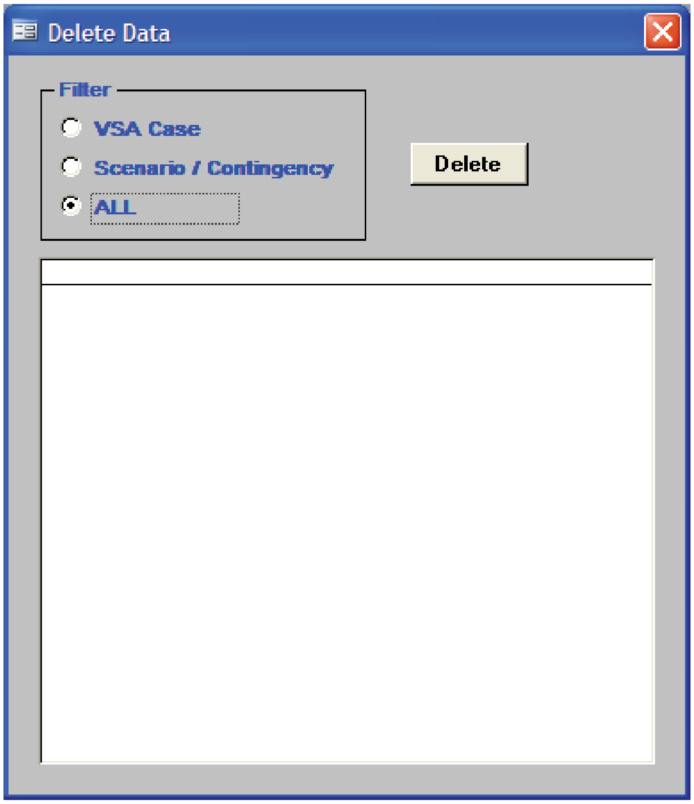


Figure A - 3.10: Deleting Data from VCA Database

c. Setting Parameters for VSAT Modal Analysis

The only parameter for VSAT modal analysis that is set from within the VCA Identification Program interface is the required margin. To set the margin select "Setting" -> "Required Margin" as shown in Figure A - 3.7. This parameter needs to be set prior to running VSAT modal analysis, otherwise a default value will be used. For detailed description on how this margin is used in the program users should consult the chapter on reactive power reserve calculation (Section 5:).

Figure A - 3.11: Setting Required Margin for VSAT Modal Analysis

d. Running VSAT Modal Analysis and Importing Results Into VCA Database

To run VSAT modal analysis and import (load) results into VCA database, “Analysis” -> “VSAT Modal” item should be selected (see Figure A - 3.4). The modal analysis dialog appears in the figure shown below:

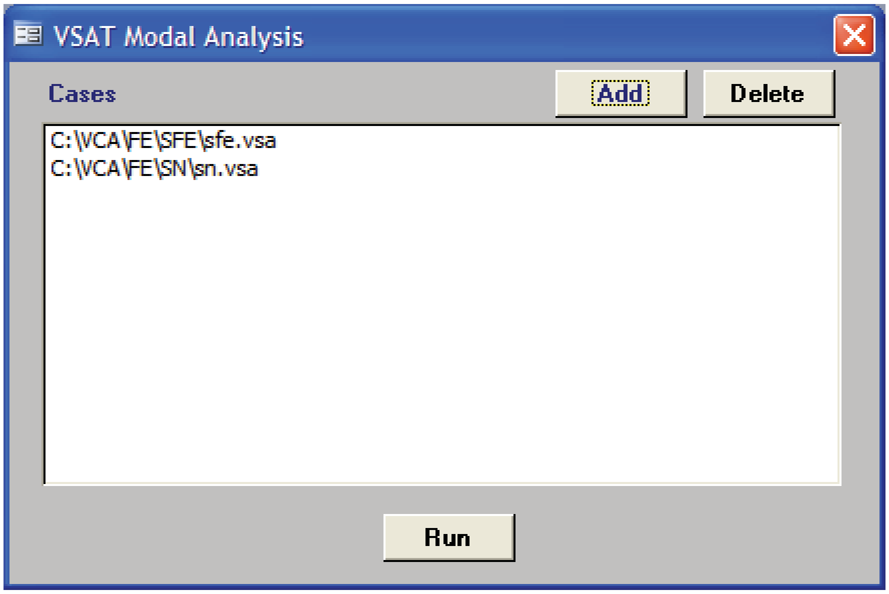
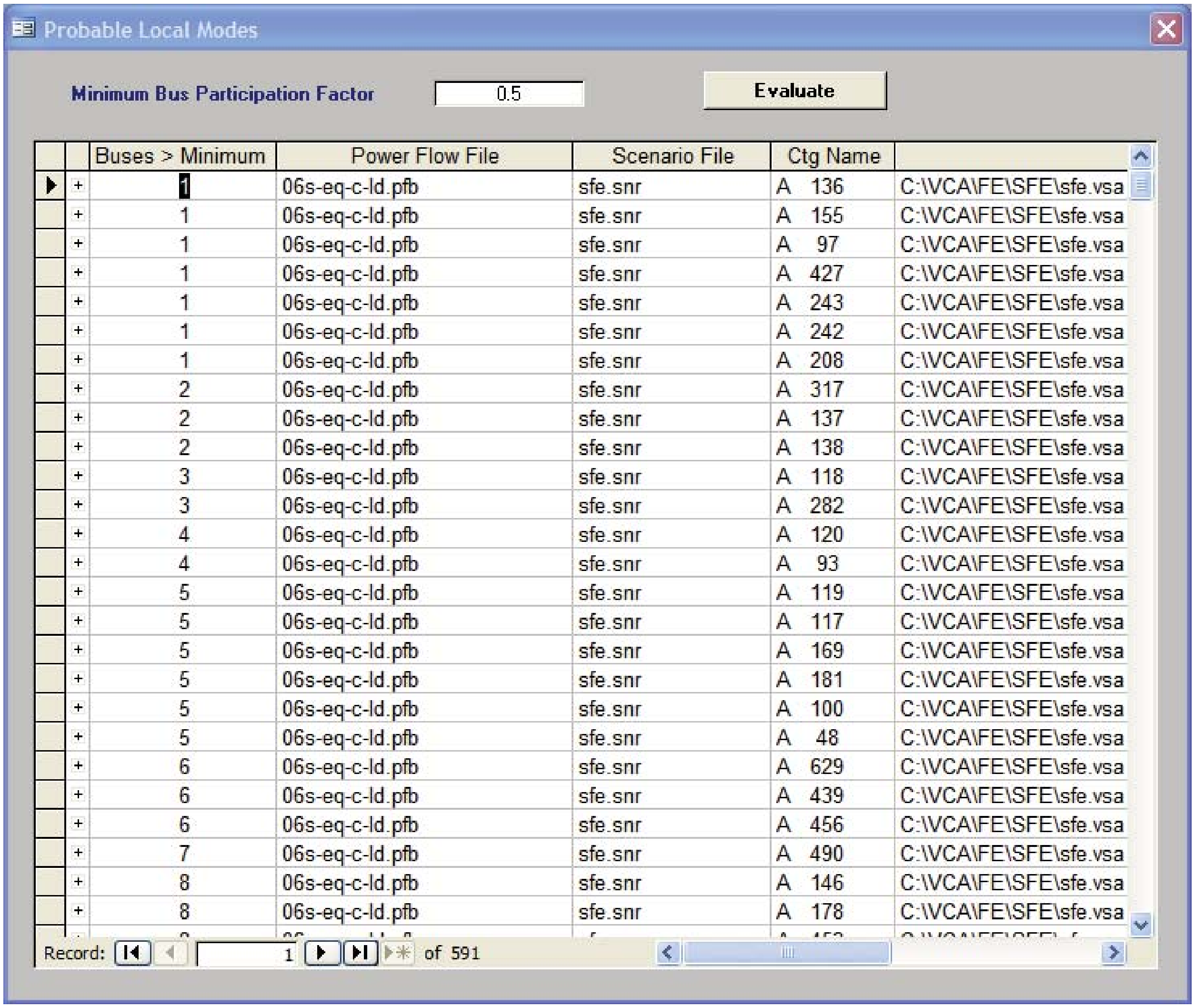


Figure A - 3.12: Running VSAT Modal Analysis and Importing of Results into VCA Database

As seen above, “Add” button can be used to locate and select VSAT scenario files. Parameters used for modal analysis are set in a VSAT parameter file associated with a chosen scenario. By pressing “Run” button VSAT modal analysis is initiated and results are automatically loaded into the VCA database. Depending on the size of the system to be analyzed and a number of considered contingencies associated with the case (as well as computer capabilities), this part of the program execution **could take several hours**.

e. Examining Probable Local Modes

To view and examine probable local modes select “Report” -> “Probable Local Modes”, as shown in Figure A - 3.6. Local modes indicate small, localized areas prone to voltage instability that are not normally of interest in the VCA identification process. A sample of a probable local modes listing is shown in Figure A - 3.13. User may choose to eliminate local modes by applying remedial actions (e.g. load shedding) and repeating the procedure from step d (re-running VSAT modal analysis). Note the program will display a count of buses having PF greater than the specified threshold (in the below example 0.5 is selected).



Buses > Minimum	Power Flow File	Scenario File	Ctg Name	
1	06s-eq-c-ld.pfb	sfe.snr	A 136	C:\VCA\FE\SFE\sfe.vsa
1	06s-eq-c-ld.pfb	sfe.snr	A 155	C:\VCA\FE\SFE\sfe.vsa
1	06s-eq-c-ld.pfb	sfe.snr	A 97	C:\VCA\FE\SFE\sfe.vsa
1	06s-eq-c-ld.pfb	sfe.snr	A 427	C:\VCA\FE\SFE\sfe.vsa
1	06s-eq-c-ld.pfb	sfe.snr	A 243	C:\VCA\FE\SFE\sfe.vsa
1	06s-eq-c-ld.pfb	sfe.snr	A 242	C:\VCA\FE\SFE\sfe.vsa
1	06s-eq-c-ld.pfb	sfe.snr	A 208	C:\VCA\FE\SFE\sfe.vsa
2	06s-eq-c-ld.pfb	sfe.snr	A 317	C:\VCA\FE\SFE\sfe.vsa
2	06s-eq-c-ld.pfb	sfe.snr	A 137	C:\VCA\FE\SFE\sfe.vsa
2	06s-eq-c-ld.pfb	sfe.snr	A 138	C:\VCA\FE\SFE\sfe.vsa
3	06s-eq-c-ld.pfb	sfe.snr	A 118	C:\VCA\FE\SFE\sfe.vsa
3	06s-eq-c-ld.pfb	sfe.snr	A 282	C:\VCA\FE\SFE\sfe.vsa
4	06s-eq-c-ld.pfb	sfe.snr	A 120	C:\VCA\FE\SFE\sfe.vsa
4	06s-eq-c-ld.pfb	sfe.snr	A 93	C:\VCA\FE\SFE\sfe.vsa
5	06s-eq-c-ld.pfb	sfe.snr	A 119	C:\VCA\FE\SFE\sfe.vsa
5	06s-eq-c-ld.pfb	sfe.snr	A 117	C:\VCA\FE\SFE\sfe.vsa
5	06s-eq-c-ld.pfb	sfe.snr	A 169	C:\VCA\FE\SFE\sfe.vsa
5	06s-eq-c-ld.pfb	sfe.snr	A 181	C:\VCA\FE\SFE\sfe.vsa
5	06s-eq-c-ld.pfb	sfe.snr	A 100	C:\VCA\FE\SFE\sfe.vsa
5	06s-eq-c-ld.pfb	sfe.snr	A 48	C:\VCA\FE\SFE\sfe.vsa
6	06s-eq-c-ld.pfb	sfe.snr	A 629	C:\VCA\FE\SFE\sfe.vsa
6	06s-eq-c-ld.pfb	sfe.snr	A 439	C:\VCA\FE\SFE\sfe.vsa
6	06s-eq-c-ld.pfb	sfe.snr	A 456	C:\VCA\FE\SFE\sfe.vsa
7	06s-eq-c-ld.pfb	sfe.snr	A 490	C:\VCA\FE\SFE\sfe.vsa
8	06s-eq-c-ld.pfb	sfe.snr	A 146	C:\VCA\FE\SFE\sfe.vsa
8	06s-eq-c-ld.pfb	sfe.snr	A 178	C:\VCA\FE\SFE\sfe.vsa

Figure A - 3.13: Examining Probable Local Modes

f. Setting Parameters for VCA Identification

In order to set parameters for VCA identification process select "Settings" -> "VCA Parameters" from the main menu, as shown in Figure A - 3.7. The screen for setting VCA parameters is shown in Figure A - 3.14 below. These parameters are described in detail in the chapter on VCA identification process (Section 4:). The parameters need to be set before running VCA identification; otherwise default values will be used.

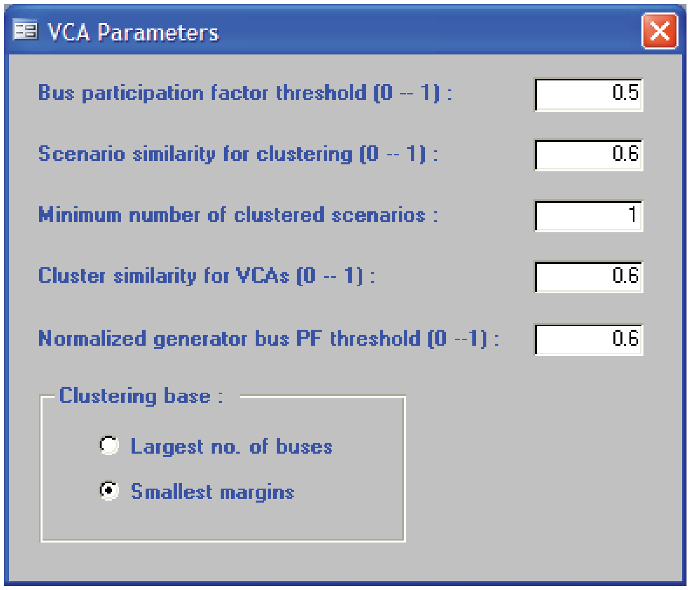


Figure A - 3.14: Setting VCA Identification Parameters

Another useful feature in the VCA identification process is to exclude generators from the list of controlling VCA generators if they do not satisfy minimum requirements set by the user. These minimum requirements are based on units' size (MVA rating) and reactive power capability. To set the minimum requirements for VCA generators select "Setting" -> "Excluded Generators", as shown in Figure A - 3.7, and set the values displayed in Figure A - 3.15.

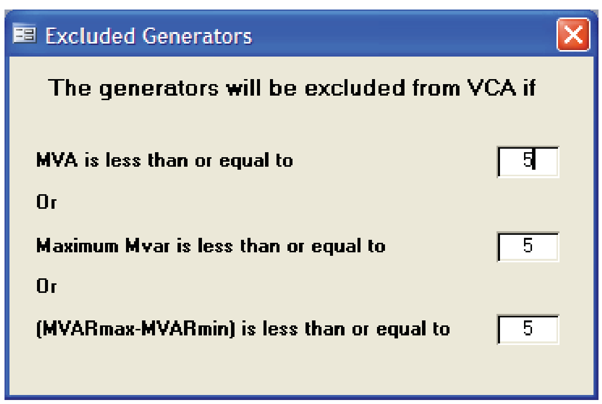


Figure A - 3.15: Setting Excluded Generators in VCA Identification

g. Running VCA Identification

The results of VSAT modal analysis stored in the VCA database are exported into an ASCII file to be used by VCA identification program. The database information is exported and VCA identification program is run by selecting "Analysis" -> "VCA Identification" as shown in Figure A - 3.4. The user may use selected or all records from VCA database for VCA identification, as shown in Figure A - 3.16.

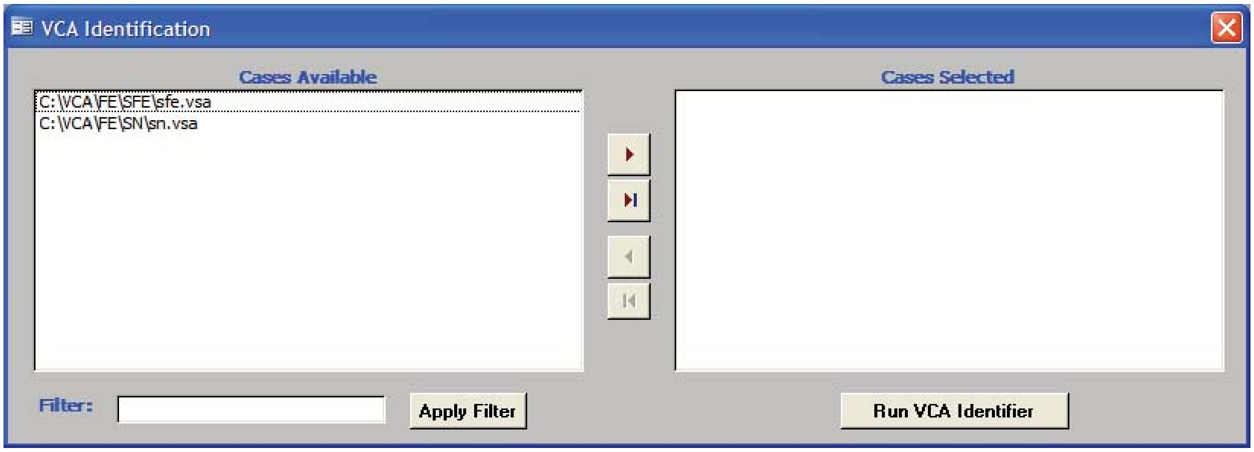


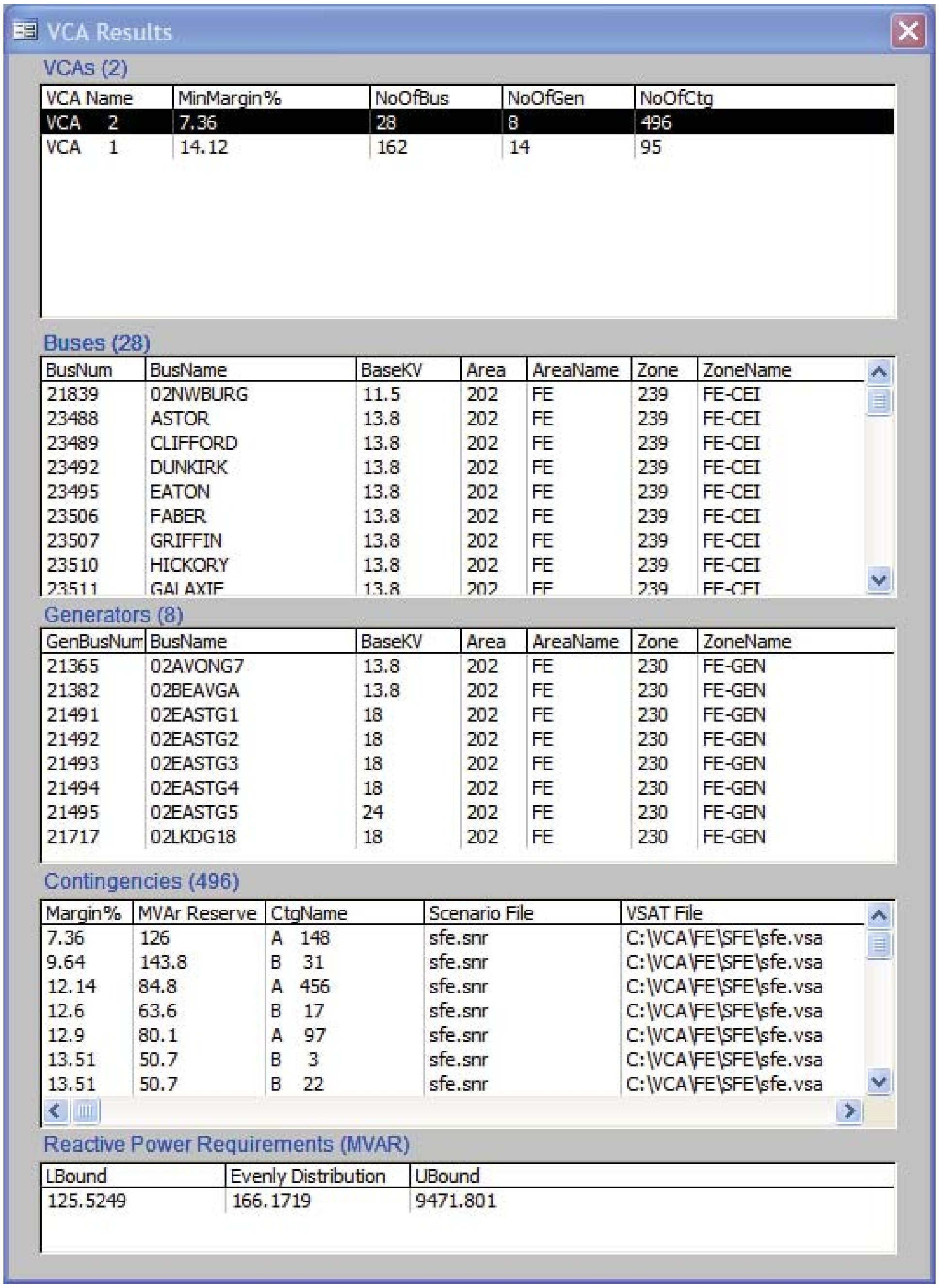
Figure A - 3.16: Exporting the VCA Database and Running VCA Identification Program

h. Examining VCA Identification Results

To obtain reports of VCA identification select "Report" -> "VCA Results" as shown in Figure A - 3.6. A sample VCA identification result is shown in Figure A - 3.17. Details of each VCA are displayed, namely associated VCA buses, controlling generators and critical contingencies with stability margin, as well as computed reactive power requirements.

The three values for VCA reactive power requirement ("Lbound", "Even Distribution", and "Ubound") represent:

- Lbound – reactive power requirement based on linear programming (LP) procedure described in Section 5:, where individual sensitivities of the corresponding VCA's generators are considered
- Even Distribution – reactive power requirement based on an average sensitivity among the corresponding VCA's generators
- Ubound – reactive power requirement based on a minimum sensitivity recorded among the corresponding VCA's generators (normally this results in an unreasonably high reactive power requirement)



VCA Results

VCAs (2)

VCA Name	MinMargin%	NoOfBus	NoOfGen	NoOfCtg
VCA 2	7.36	28	8	496
VCA 1	14.12	162	14	95

Buses (28)

BusNum	BusName	BaseKV	Area	AreaName	Zone	ZoneName
21839	02NWBURG	11.5	202	FE	239	FE-CEI
23488	ASTOR	13.8	202	FE	239	FE-CEI
23489	CLIFFORD	13.8	202	FE	239	FE-CEI
23492	DUNKIRK	13.8	202	FE	239	FE-CEI
23495	EATON	13.8	202	FE	239	FE-CEI
23506	FABER	13.8	202	FE	239	FE-CEI
23507	GRIFFIN	13.8	202	FE	239	FE-CEI
23510	HICKORY	13.8	202	FE	239	FE-CEI
23511	GALAXIE	13.8	202	FE	239	FE-CEI

Generators (8)

GenBusNum	BusName	BaseKV	Area	AreaName	Zone	ZoneName
21365	02AVONG7	13.8	202	FE	230	FE-GEN
21382	02BEAVGA	13.8	202	FE	230	FE-GEN
21491	02EASTG1	18	202	FE	230	FE-GEN
21492	02EASTG2	18	202	FE	230	FE-GEN
21493	02EASTG3	18	202	FE	230	FE-GEN
21494	02EASTG4	18	202	FE	230	FE-GEN
21495	02EASTG5	24	202	FE	230	FE-GEN
21717	02LKDG18	18	202	FE	230	FE-GEN

Contingencies (496)

Margin%	MVAr Reserve	CtgName	Scenario File	VSAT File
7.36	126	A 148	sfe.snr	C:\VCA\FE\SFE\sfe.vsa
9.64	143.8	B 31	sfe.snr	C:\VCA\FE\SFE\sfe.vsa
12.14	84.8	A 456	sfe.snr	C:\VCA\FE\SFE\sfe.vsa
12.6	63.6	B 17	sfe.snr	C:\VCA\FE\SFE\sfe.vsa
12.9	80.1	A 97	sfe.snr	C:\VCA\FE\SFE\sfe.vsa
13.51	50.7	B 3	sfe.snr	C:\VCA\FE\SFE\sfe.vsa
13.51	50.7	B 22	sfe.snr	C:\VCA\FE\SFE\sfe.vsa

Reactive Power Requirements (MVAR)

LBound	Evenly Distribution	UBound
125.5249	166.1719	9471.801

Figure A - 3.17: Examining VCA Buses, Associated Generators, and Stability Margin of each VCA

i. Examining VSAT Output/Input Data

For user convenience a set of VSAT input and output data can be examined in the database by selecting “Data” -> “VSAT Output / Input”, as shown in Figure A - 3.5. VSAT input data includes power flow, contingency list, transfer description etc. The output includes the reports of modal and sensitivity analysis. The screen for examining of VSAT data is shown in Figure A - 3.18.

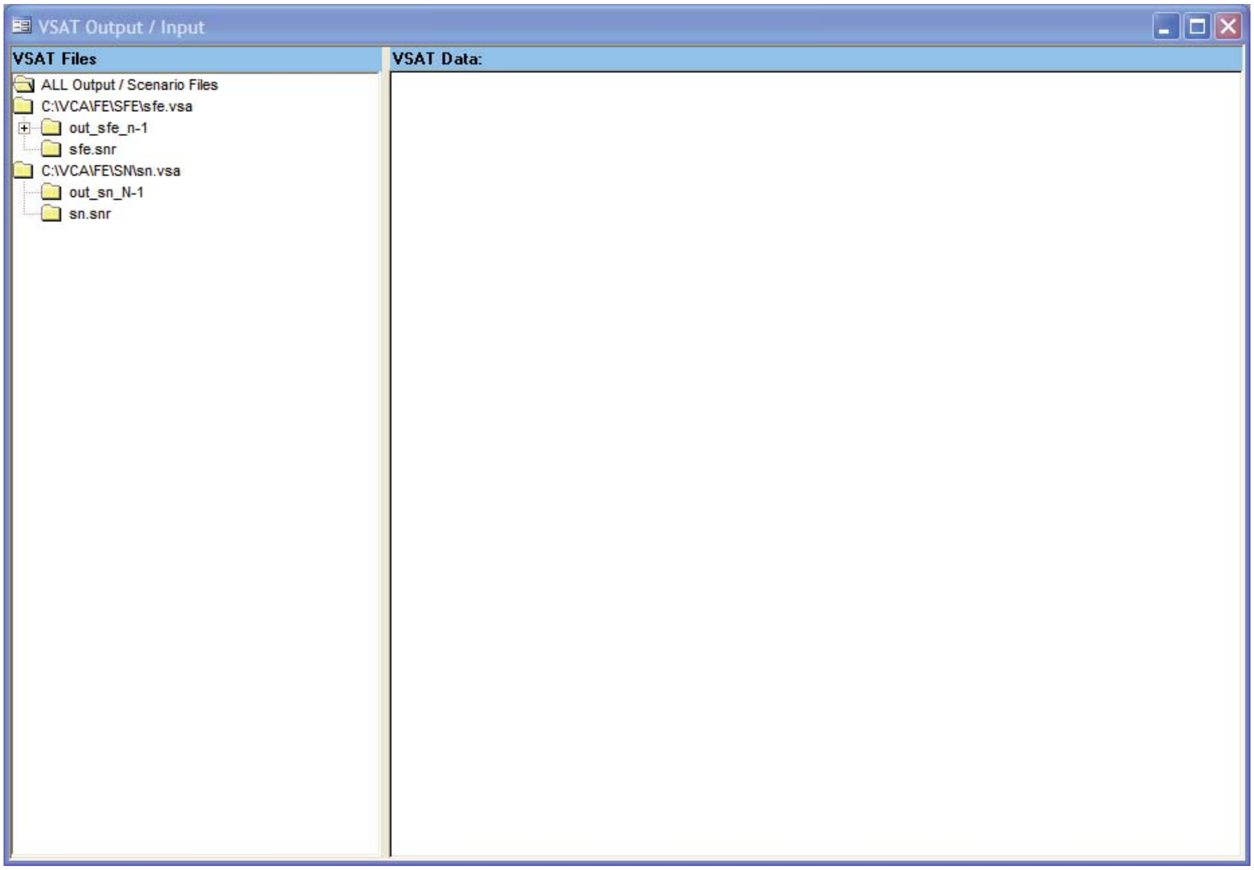
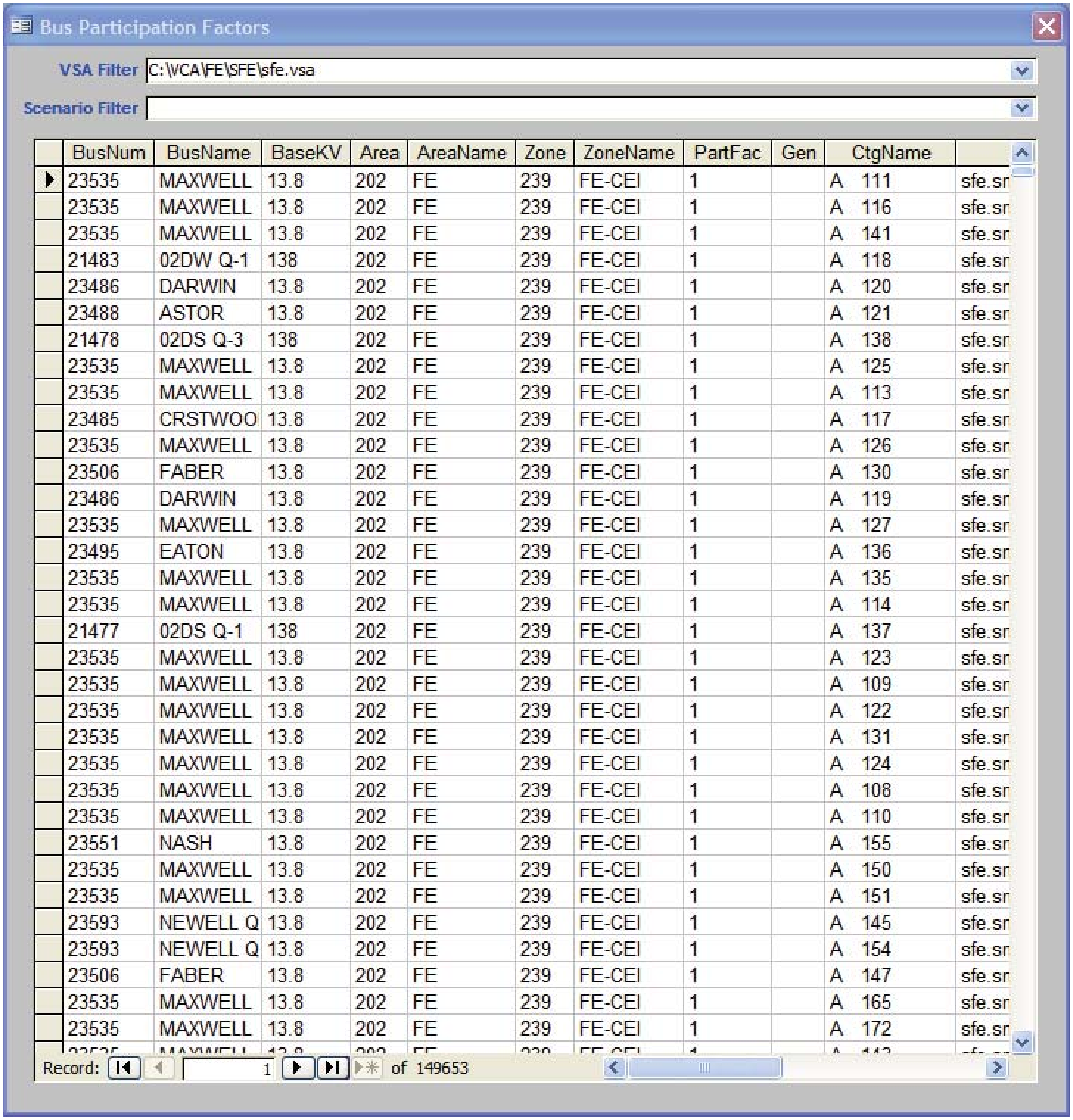


Figure A - 3.18: Examining VSAT Output/Input Files

j. Examining Results of Modal Analysis

To selectively examine the results of VSAT modal analysis in the VCA database select "Data" -> "Bus Participation Factors" option as shown in Figure A - 3.5. Figure A - 3.19 shows a view of the database records and scenarios/contingency filters that may be used to examine selected records.

The eigenvalues for the scenarios/contingencies stored in the VCA database can also be selectively examined by choosing "Data" -> "Eigen Values" as shown in Figure A - 3.5. A sample list of eigenvalues and filtering capabilities are shown in Figure A - 3.20.



Bus Participation Factors

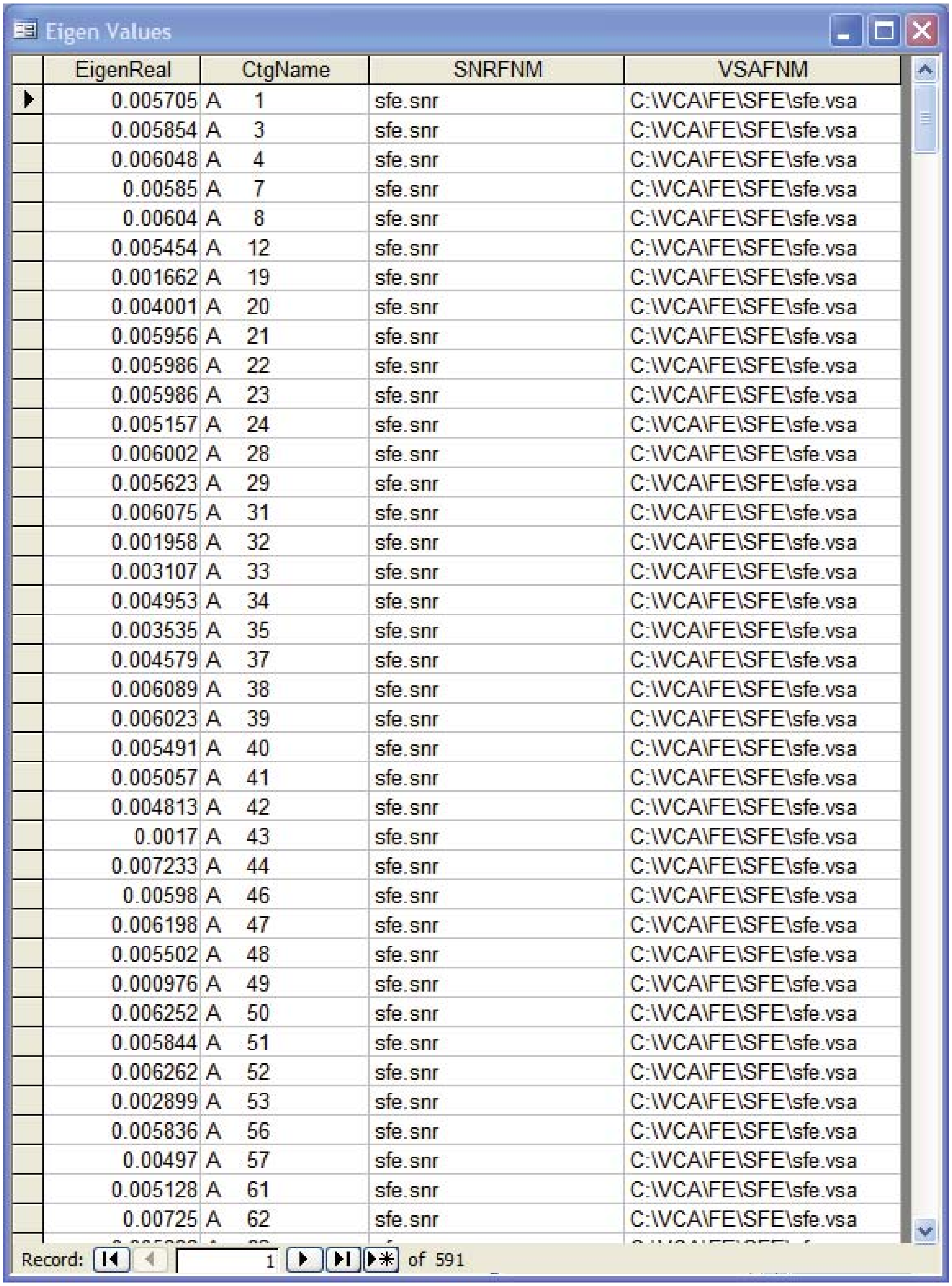
VSA Filter C:\VCA\FE\SFE\sfe.vsa

Scenario Filter

BusNum	BusName	BaseKV	Area	AreaName	Zone	ZoneName	PartFac	Gen	CtgName	
23535	MAXWELL	13.8	202	FE	239	FE-CEI	1		A 111	sfe.sr
23535	MAXWELL	13.8	202	FE	239	FE-CEI	1		A 116	sfe.sr
23535	MAXWELL	13.8	202	FE	239	FE-CEI	1		A 141	sfe.sr
21483	02DW Q-1	138	202	FE	239	FE-CEI	1		A 118	sfe.sr
23486	DARWIN	13.8	202	FE	239	FE-CEI	1		A 120	sfe.sr
23488	ASTOR	13.8	202	FE	239	FE-CEI	1		A 121	sfe.sr
21478	02DS Q-3	138	202	FE	239	FE-CEI	1		A 138	sfe.sr
23535	MAXWELL	13.8	202	FE	239	FE-CEI	1		A 125	sfe.sr
23535	MAXWELL	13.8	202	FE	239	FE-CEI	1		A 113	sfe.sr
23485	CRSTWOO	13.8	202	FE	239	FE-CEI	1		A 117	sfe.sr
23535	MAXWELL	13.8	202	FE	239	FE-CEI	1		A 126	sfe.sr
23506	FABER	13.8	202	FE	239	FE-CEI	1		A 130	sfe.sr
23486	DARWIN	13.8	202	FE	239	FE-CEI	1		A 119	sfe.sr
23535	MAXWELL	13.8	202	FE	239	FE-CEI	1		A 127	sfe.sr
23495	EATON	13.8	202	FE	239	FE-CEI	1		A 136	sfe.sr
23535	MAXWELL	13.8	202	FE	239	FE-CEI	1		A 135	sfe.sr
23535	MAXWELL	13.8	202	FE	239	FE-CEI	1		A 114	sfe.sr
21477	02DS Q-1	138	202	FE	239	FE-CEI	1		A 137	sfe.sr
23535	MAXWELL	13.8	202	FE	239	FE-CEI	1		A 123	sfe.sr
23535	MAXWELL	13.8	202	FE	239	FE-CEI	1		A 109	sfe.sr
23535	MAXWELL	13.8	202	FE	239	FE-CEI	1		A 122	sfe.sr
23535	MAXWELL	13.8	202	FE	239	FE-CEI	1		A 131	sfe.sr
23535	MAXWELL	13.8	202	FE	239	FE-CEI	1		A 124	sfe.sr
23535	MAXWELL	13.8	202	FE	239	FE-CEI	1		A 108	sfe.sr
23535	MAXWELL	13.8	202	FE	239	FE-CEI	1		A 110	sfe.sr
23551	NASH	13.8	202	FE	239	FE-CEI	1		A 155	sfe.sr
23535	MAXWELL	13.8	202	FE	239	FE-CEI	1		A 150	sfe.sr
23535	MAXWELL	13.8	202	FE	239	FE-CEI	1		A 151	sfe.sr
23593	NEWELL Q	13.8	202	FE	239	FE-CEI	1		A 145	sfe.sr
23593	NEWELL Q	13.8	202	FE	239	FE-CEI	1		A 154	sfe.sr
23506	FABER	13.8	202	FE	239	FE-CEI	1		A 147	sfe.sr
23535	MAXWELL	13.8	202	FE	239	FE-CEI	1		A 165	sfe.sr
23535	MAXWELL	13.8	202	FE	239	FE-CEI	1		A 172	sfe.sr

Record: 1 of 149653

Figure A - 3.19: Examining Details of Bus Participation Factors in the VCA Database



Eigen Values

EigenReal	CtgName	SNRFNM	VSAFNM
0.005705	A 1	sfe.snr	C:\VCA\FE\SFE\sfe.vsa
0.005854	A 3	sfe.snr	C:\VCA\FE\SFE\sfe.vsa
0.006048	A 4	sfe.snr	C:\VCA\FE\SFE\sfe.vsa
0.00585	A 7	sfe.snr	C:\VCA\FE\SFE\sfe.vsa
0.00604	A 8	sfe.snr	C:\VCA\FE\SFE\sfe.vsa
0.005454	A 12	sfe.snr	C:\VCA\FE\SFE\sfe.vsa
0.001662	A 19	sfe.snr	C:\VCA\FE\SFE\sfe.vsa
0.004001	A 20	sfe.snr	C:\VCA\FE\SFE\sfe.vsa
0.005956	A 21	sfe.snr	C:\VCA\FE\SFE\sfe.vsa
0.005986	A 22	sfe.snr	C:\VCA\FE\SFE\sfe.vsa
0.005986	A 23	sfe.snr	C:\VCA\FE\SFE\sfe.vsa
0.005157	A 24	sfe.snr	C:\VCA\FE\SFE\sfe.vsa
0.006002	A 28	sfe.snr	C:\VCA\FE\SFE\sfe.vsa
0.005623	A 29	sfe.snr	C:\VCA\FE\SFE\sfe.vsa
0.006075	A 31	sfe.snr	C:\VCA\FE\SFE\sfe.vsa
0.001958	A 32	sfe.snr	C:\VCA\FE\SFE\sfe.vsa
0.003107	A 33	sfe.snr	C:\VCA\FE\SFE\sfe.vsa
0.004953	A 34	sfe.snr	C:\VCA\FE\SFE\sfe.vsa
0.003535	A 35	sfe.snr	C:\VCA\FE\SFE\sfe.vsa
0.004579	A 37	sfe.snr	C:\VCA\FE\SFE\sfe.vsa
0.006089	A 38	sfe.snr	C:\VCA\FE\SFE\sfe.vsa
0.006023	A 39	sfe.snr	C:\VCA\FE\SFE\sfe.vsa
0.005491	A 40	sfe.snr	C:\VCA\FE\SFE\sfe.vsa
0.005057	A 41	sfe.snr	C:\VCA\FE\SFE\sfe.vsa
0.004813	A 42	sfe.snr	C:\VCA\FE\SFE\sfe.vsa
0.0017	A 43	sfe.snr	C:\VCA\FE\SFE\sfe.vsa
0.007233	A 44	sfe.snr	C:\VCA\FE\SFE\sfe.vsa
0.00598	A 46	sfe.snr	C:\VCA\FE\SFE\sfe.vsa
0.006198	A 47	sfe.snr	C:\VCA\FE\SFE\sfe.vsa
0.005502	A 48	sfe.snr	C:\VCA\FE\SFE\sfe.vsa
0.000976	A 49	sfe.snr	C:\VCA\FE\SFE\sfe.vsa
0.006252	A 50	sfe.snr	C:\VCA\FE\SFE\sfe.vsa
0.005844	A 51	sfe.snr	C:\VCA\FE\SFE\sfe.vsa
0.006262	A 52	sfe.snr	C:\VCA\FE\SFE\sfe.vsa
0.002899	A 53	sfe.snr	C:\VCA\FE\SFE\sfe.vsa
0.005836	A 56	sfe.snr	C:\VCA\FE\SFE\sfe.vsa
0.00497	A 57	sfe.snr	C:\VCA\FE\SFE\sfe.vsa
0.005128	A 61	sfe.snr	C:\VCA\FE\SFE\sfe.vsa
0.00725	A 62	sfe.snr	C:\VCA\FE\SFE\sfe.vsa

Record: 1 of 591

Figure A - 3.20: Examining Modes in the VCA Database

k. Importing Previous Database

To further analyze the records in previously saved databases select "Data" -> "Import Database" as shown in Figure A - 3.5. By clicking "Browse" button in the open dialog, as displayed in Figure A - 3.21, the user is able to search for other database files (*.mdb) and import (load) information into the current database. The current database records are deleted prior to importing (a warning is issued as in Figure A - 3.22); therefore the current database should be saved under a different name (e.g. vca_old.mdb) before using this function.

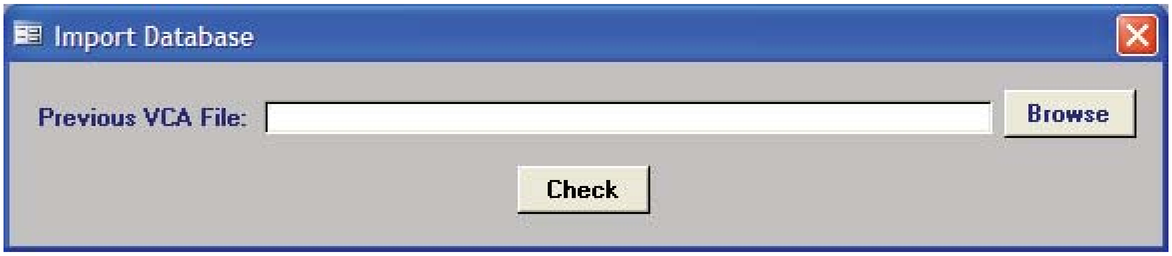


Figure A - 3.21: Importing Previous Database

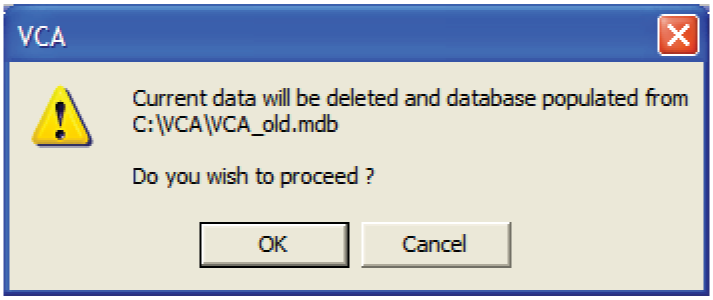


Figure A - 3.22: Import Database Warning

l. Setting Program Version

To set the user version of the VCA database select "Setting" -> "Version" from the main menu, as shown in Figure A - 3.7. Major and minor version numbers in Figure A - 3.23 are set by the software developer (PLI) and cannot be changed by the user as they indicate the change in functionality of VCA Identification Program. The user has an option of changing the user version indicating, for example, the change of input data to the program.

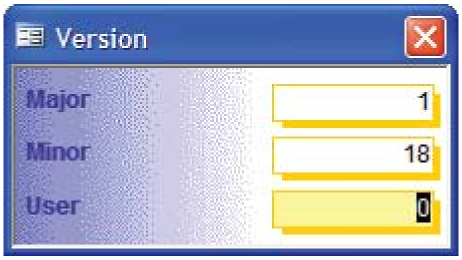


Figure A - 3.23: Setting VCA Identification Program Version

m. Compacting and Repairing Database

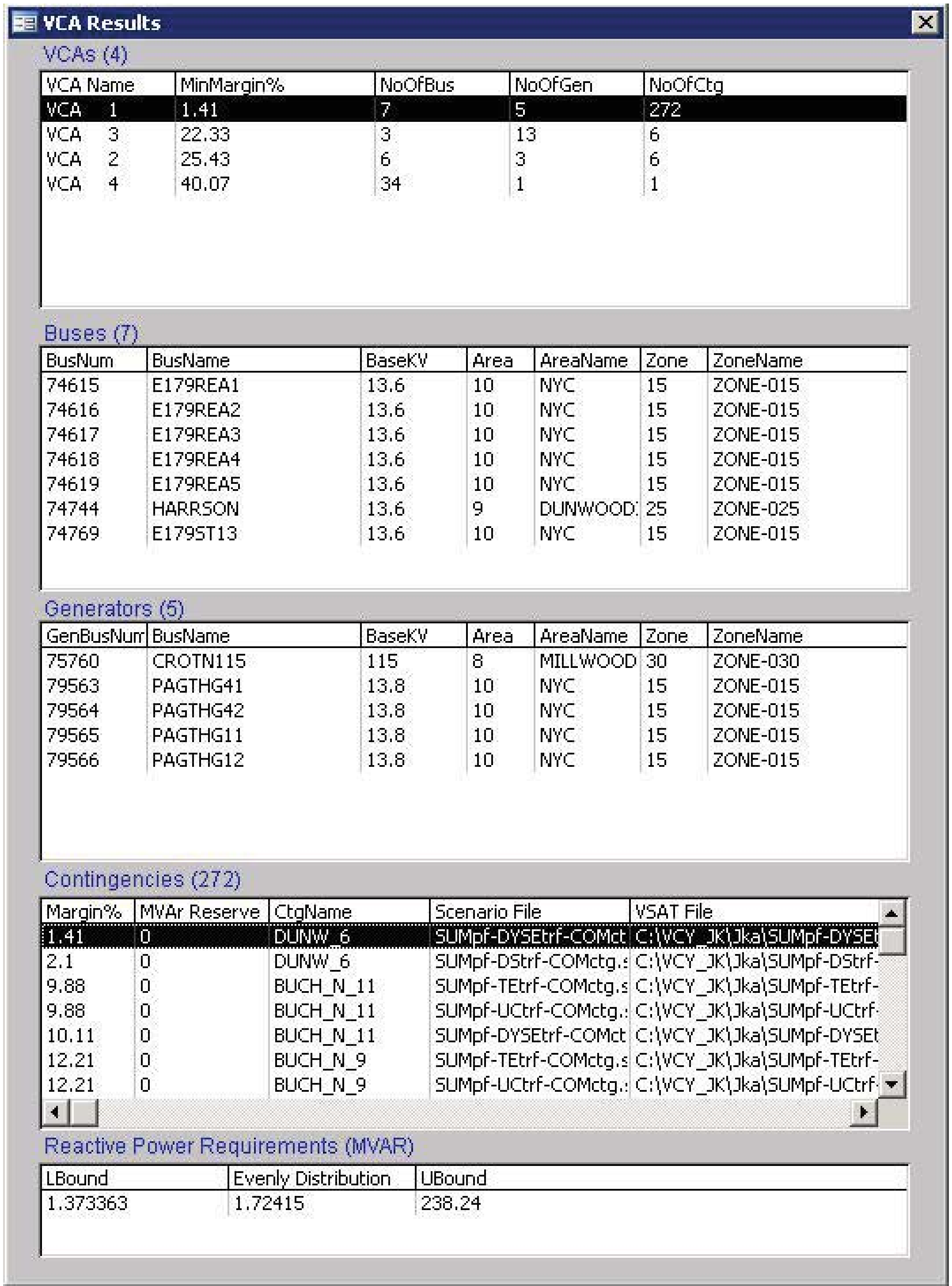
Successive deleting and adding of new scenarios to the VCA database increases its size on the disk regardless of the amount of data stored in the database. To release the empty s in the database and compact its size select "Tools" -> "Compact and Repair Database…" as shown in Figure A - 3.8.

Section A-4: Proprietary/Masked Information

- Name changes relevant to Identified VCAs:

Table A - 4.1: Name changes and proprietary information

Stated as	To be read as
Station EST_XX	East 179th St.
Station FRG_XX	Farragut station
Station ERV_XX	E. River station
Station KNC_XX	Klinekill & Craryville stations
Area 1XX0	Area 10
Zone 1XX5	Zone 15
Owner CXXD	Owner ConED
Area 6XX	Area 6
Zone 2XX1	Zone 21
Owner NXXG	Owner NYSEG



VCA Results

VCAs (4)

VCA Name	MinMargin%	NoOfBus	NoOfGen	NoOfCtg
VCA 1	1.41	7	5	272
VCA 3	22.33	3	13	6
VCA 2	25.43	6	3	6
VCA 4	40.07	34	1	1

Buses (7)

BusNum	BusName	BaseKV	Area	AreaName	Zone	ZoneName
74615	E179REA1	13.6	10	NYC	15	ZONE-015
74616	E179REA2	13.6	10	NYC	15	ZONE-015
74617	E179REA3	13.6	10	NYC	15	ZONE-015
74618	E179REA4	13.6	10	NYC	15	ZONE-015
74619	E179REA5	13.6	10	NYC	15	ZONE-015
74744	HARRSON	13.6	9	DUNWOOD:	25	ZONE-025
74769	E179ST13	13.6	10	NYC	15	ZONE-015

Generators (5)

GenBusNum	BusName	BaseKV	Area	AreaName	Zone	ZoneName
75760	CROTN115	115	8	MILLWOOD	30	ZONE-030
79563	PAGTHG41	13.8	10	NYC	15	ZONE-015
79564	PAGTHG42	13.8	10	NYC	15	ZONE-015
79565	PAGTHG11	13.8	10	NYC	15	ZONE-015
79566	PAGTHG12	13.8	10	NYC	15	ZONE-015

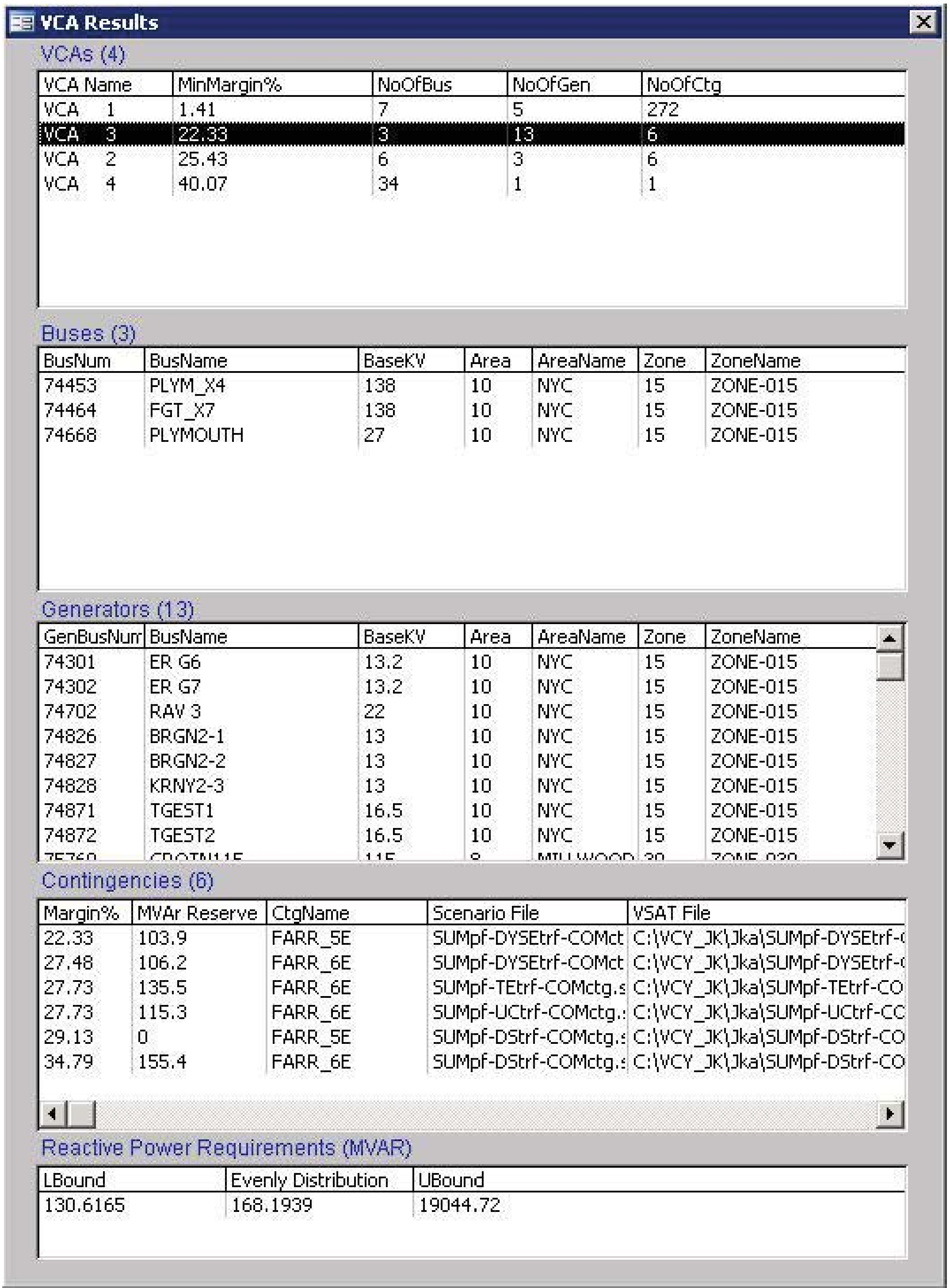
Contingencies (272)

Margin%	MVAr Reserve	CtgName	Scenario File	VSAT File
1.41	0	DUNW_6	SUMpf-DYSEtrf-COMct	C:\VCY_JK\Jka\SUMpf-DYSEt
2.1	0	DUNW_6	SUMpf-DStrf-COMctg.s	C:\VCY_JK\Jka\SUMpf-DStrf-
9.88	0	BUCH_N_11	SUMpf-TEtrf-COMctg.s	C:\VCY_JK\Jka\SUMpf-TEtrf-
9.88	0	BUCH_N_11	SUMpf-UCtrf-COMctg.:	C:\VCY_JK\Jka\SUMpf-UCtrf-
10.11	0	BUCH_N_11	SUMpf-DYSEtrf-COMct	C:\VCY_JK\Jka\SUMpf-DYSEt
12.21	0	BUCH_N_9	SUMpf-TEtrf-COMctg.s	C:\VCY_JK\Jka\SUMpf-TEtrf-
12.21	0	BUCH_N_9	SUMpf-UCtrf-COMctg.:	C:\VCY_JK\Jka\SUMpf-UCtrf-

Reactive Power Requirements (MVAR)

LBound	Evenly Distribution	UBound
1.373363	1.72415	238.24

Figure A - 4.1: Details of VCA#1



VCA Results

VCAs (4)

VCA Name	MinMargin%	NoOfBus	NoOfGen	NoOfCtg
VCA 1	1.41	7	5	272
VCA 3	22.33	3	13	6
VCA 2	25.43	6	3	6
VCA 4	40.07	34	1	1

Buses (3)

BusNum	BusName	BaseKV	Area	AreaName	Zone	ZoneName
74453	PLYM_X4	138	10	NYC	15	ZONE-015
74464	FGT_X7	138	10	NYC	15	ZONE-015
74668	PLYMOUTH	27	10	NYC	15	ZONE-015

Generators (13)

GenBusNum	BusName	BaseKV	Area	AreaName	Zone	ZoneName
74301	ER G6	13.2	10	NYC	15	ZONE-015
74302	ER G7	13.2	10	NYC	15	ZONE-015
74702	RAV 3	22	10	NYC	15	ZONE-015
74826	BRGN2-1	13	10	NYC	15	ZONE-015
74827	BRGN2-2	13	10	NYC	15	ZONE-015
74828	KRNY2-3	13	10	NYC	15	ZONE-015
74871	TGEST1	16.5	10	NYC	15	ZONE-015
74872	TGEST2	16.5	10	NYC	15	ZONE-015

Contingencies (6)

Margin%	MVAr Reserve	CtgName	Scenario File	VSAT File
22.33	103.9	FARR_5E	SUMpf-DYSEtrf-COMct	C:\VCY_JK\Jka\SUMpf-DYSEtrf-
27.48	106.2	FARR_6E	SUMpf-DYSEtrf-COMct	C:\VCY_JK\Jka\SUMpf-DYSEtrf-
27.73	135.5	FARR_6E	SUMpf-TEtrf-COMctg.s	C:\VCY_JK\Jka\SUMpf-TEtrf-CO
27.73	115.3	FARR_6E	SUMpf-UCtrf-COMctg.	C:\VCY_JK\Jka\SUMpf-UCtrf-CC
29.13	0	FARR_5E	SUMpf-DStrf-COMctg.s	C:\VCY_JK\Jka\SUMpf-DStrf-CO
34.79	155.4	FARR_6E	SUMpf-DStrf-COMctg.s	C:\VCY_JK\Jka\SUMpf-DStrf-CO

Reactive Power Requirements (MVAR)

LBound	Evenly Distribution	UBound
130.6165	168.1939	19044.72

Figure A - 4.2: Details of VCA#2

VCA Results

VCAs (4)

VCA Name	MinMargin%	NoOfBus	NoOfGen	NoOfCtg
VCA 1	1.41	7	5	272
VCA 3	22.33	3	13	6
VCA 2	25.43	6	3	6
VCA 4	40.07	34	1	1

Buses (6)

BusNum	BusName	BaseKV	Area	AreaName	Zone	ZoneName
74765	AVENUEA	13.6	10	NYC	15	ZONE-015
74769	E179ST13	13.6	10	NYC	15	ZONE-015
74770	E29ST	13.6	10	NYC	15	ZONE-015
74781	LENRDST1	13.6	10	NYC	15	ZONE-015
74782	LENRDST2	13.6	10	NYC	15	ZONE-015
74802	W19TH ST	13.6	10	NYC	15	ZONE-015

Generators (3)

GenBusNum	BusName	BaseKV	Area	AreaName	Zone	ZoneName
74301	ER G6	13.2	10	NYC	15	ZONE-015
74302	ER G7	13.2	10	NYC	15	ZONE-015
75760	CROTN115	115	8	MILLWOOD	30	ZONE-030

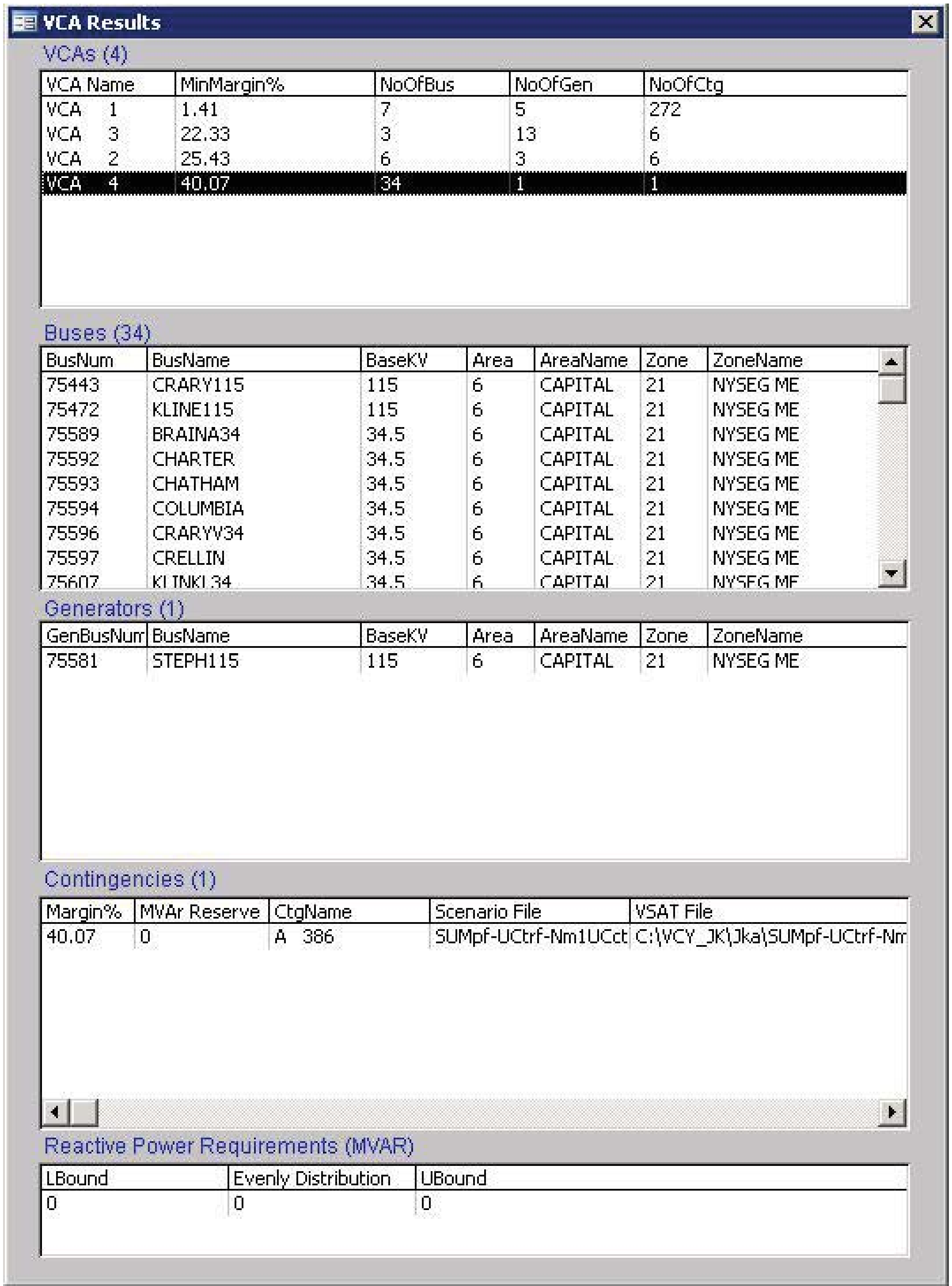
Contingencies (6)

Margin%	MVAr Reserve	CtgName	Scenario File	VSAT File
25.43	0	SPRA_RNS5	SUMpf-TEtrf-COMctg.s	C:\VCY_JK\Jka\SUMpf-TEtrf-CO
25.43	0	SPRA_RNS5	SUMpf-UCtrf-COMctg.:	C:\VCY_JK\Jka\SUMpf-UCtrf-CC
31.21	0	FARR_8E	SUMpf-DYSEtrf-COMct	C:\VCY_JK\Jka\SUMpf-DYSEtrf-(
31.98	0	FARR_7E	SUMpf-DYSEtrf-COMct	C:\VCY_JK\Jka\SUMpf-DYSEtrf-(
32.36	0	FARR_7E	SUMpf-UCtrf-COMctg.:	C:\VCY_JK\Jka\SUMpf-UCtrf-CC
35.54	0	BUS-GOETHALS_N	SUMpf-DYSEtrf-COMct	C:\VCY_JK\Jka\SUMpf-DYSEtrf-(

Reactive Power Requirements (MVAR)

LBound	Evenly Distribution	UBound
0	0	0

Figure A - 4.3: Details of VCA#3



VCA Results

VCAs (4)

VCA Name	MinMargin%	NoOfBus	NoOfGen	NoOfCtg
VCA 1	1.41	7	5	272
VCA 3	22.33	3	13	6
VCA 2	25.43	6	3	6
VCA 4	40.07	34	1	1

Buses (34)

BusNum	BusName	BaseKV	Area	AreaName	Zone	ZoneName
75443	CRARY115	115	6	CAPITAL	21	NYSEG ME
75472	KLINE115	115	6	CAPITAL	21	NYSEG ME
75589	BRAINA34	34.5	6	CAPITAL	21	NYSEG ME
75592	CHARTER	34.5	6	CAPITAL	21	NYSEG ME
75593	CHATHAM	34.5	6	CAPITAL	21	NYSEG ME
75594	COLUMBIA	34.5	6	CAPITAL	21	NYSEG ME
75596	CRARYV34	34.5	6	CAPITAL	21	NYSEG ME
75597	CRELLIN	34.5	6	CAPITAL	21	NYSEG ME
75607	KLINKL34	34.5	6	CAPITAL	21	NYSEG ME

Generators (1)

GenBusNum	BusName	BaseKV	Area	AreaName	Zone	ZoneName
75581	STEPH115	115	6	CAPITAL	21	NYSEG ME

Contingencies (1)

Margin%	MVAr Reserve	CtgName	Scenario File	VSAT File
40.07	0	A 386	SUMpf-UCtrf-Nm1UCct	C:\VCY_JK\Jka\SUMpf-UCtrf-Nm

Reactive Power Requirements (MVAR)

LBound	Evenly Distribution	UBound
0	0	0

Figure A - 4.4: Details of VCA # 4

- Name changes relevant to contingency names:

An excel file titled "NameChange_COM_ctg.xls" has been supplied as part of this project's deliverable datasets.

APPENDIX C

MEASUREMENT BASED VOLTAGE STABILITY MONITORING FOR NEW YORK TRANSMISSION SYSTEM

NYSERDA AGREEMENT WITH ELECTRIC POWER RESEARCH INSTITUTE (EPRI) NO. 10470

FINAL TASK REPORT

Prepared for:

New York State Energy Research and Development Authority
Albany, NY

Project Manager
Michael P. Razanousky

Prepared by:
Electric Power Research Institute (EPRI)
3420 Hillview Avenue, Palo Alto, CA 94304

Project Managers
Dr. Stephen Lee and Dr. Liang Min

Task Manager
Dr. Liang Min

SEPTEMBER, 2010

Acknowledgements

The project was sponsored by the New York State Energy Research and Development Authority (NYSERDA). The author acknowledges the valuable help and support from CHG&E, ConEd, DPS, LIPA, National Grid, NYISO, NYPA and NYSEG. The author also extends special thanks to the NYISO technical staff (De Tran, Tao He, Zachary Smith and John Adams) and LIPA technical staff (Anie Philip, Stephen Marron, and Janos Hajagos) for their support in providing study data.

Table of Contents

List of Tables

List of Figures

Figure Title Page No.

Executive Summary

Purpose of the Study

The objectives of this project are to demonstrate the new approach developed by EPRI called the Voltage Instability Load Shedding to prevent voltage collapse with an automatic safety net or system protection scheme that will automatically shed the right amount of load to arrest an impending voltage collapse by using high-sampling rate digital measurement devices such as Digital Fault Recorder (DFR), PMU or intelligent electronic devices (IED) installed at the substation level. Demonstrate also its ability to provide real-time voltage stability margins which are computed from the real-time data of the DFR, PMU or IED. Such information will be provided to Task 2 for monitoring and visualization.

Approach, Methodology and Tools

EPRI has invented a new measurement-based wide-area voltage stability monitoring method using PMUs, which is able to continuously calculate real-time contingency-independent voltage stability margin for an interface or a load center using measurements taken at its boundary buses (Ref.4).

To validate the invention, it is necessary to determine critical substations associated with voltage stability problems. Past experiences of New York transmission planners on the potential interfaces associated with voltage instability problem are used to the maximum degree so as to select the most promising substations. We perform steady-state P-V analysis for voltage stability constrained interfaces to determine critical substations. A more intelligent way is developed to rely on visualization tools to display dynamic voltage performance for each scenario to identify voltage control areas that consistently displaying lower voltages across all scenarios.

Measurement-based voltage stability monitoring method typically contains the following steps:

- Obtain synchronized voltage and current measurements at all boundary buses using PMUs
- Determine a fictitious boundary bus representing all boundary buses, and calculate the equivalent voltage phasor, real power and reactive power at this bus
- Estimate the external system's Thevenin equivalent parameters
- Calculate power transfer limits at the interface of the load center using the Thevenin equivalent
- Calculate voltage stability margin in terms of real power and reactive power

Since PMUs are not currently available at the determined critical substations, we perform time-domain simulations using PSS/E to obtain the voltage and current waveforms as pseudo PMU data. We examine the feasibility of the proposed measurement-based voltage stability monitoring method on the Central East interface of the New York system using pseudo PMU data generated by time-domain simulation.

Results

The Measurement-base Voltage Stability Monitoring method has been validated on the Central East interface. The results show that the Measurement-base Voltage Stability Monitoring method:

- can detect voltage instability problems in real-time
- can help operators monitor system voltage stability condition by providing the power transfer limits in terms of real or reactive power.

This monitoring function does not require modeling transmission system components and does not rely on the SCADA/EMS. The margin information provides system operators not only the power transfer limit to a load center (or on the transmission corridor), in terms of active power, but also the reactive power support needed. This information can be used as decision support for operator to take actions to improve voltage stability. The set of control actions include but are not limited to:

- increasing reactive power output from generators
- switching on shunt capacitors
- increasing reactive power output from SVC
- configuration of transmission network
- load shedding

Future Work

Preliminary analytical studies in this report have demonstrated the advantages and benefits of using this technology to monitor voltage instability on the Central East interface. With all this knowledge in hand, we are collaborating with NYISO and Transmission Owners to move this invention into the pilot studies and then into full-scale demonstration.

Section 1: Background

Voltage Instability

Voltage stability is the ability of a power system to maintain adequate voltage magnitudes at buses, which is a major concern in daily power system operations and a leading factor to limit power transfers in a prevailing open access environment. The transfer of power through a transmission network is accompanied by voltage drops between the generation and consumption points. In normal operating conditions, these drops are in the order of a few percentages of the nominal voltage. One of the tasks of power system planners and operators is to check that under heavy stress conditions and/or following credible events, all bus voltages remain within acceptable bounds.

In some circumstances, however, in the seconds or minutes following a disturbance, voltages may experience large, progressive falls, which are so pronounced that the system integrity is endangered and power cannot be delivered to customers. This catastrophe is referred to as voltage instability. This instability stems from the attempt of load dynamics to restore power consumption beyond the amount that can be provided by the combined transmission and generation system.

Voltage instability is recognized as one of major threats to system operation. Voltage instability is often triggered by tripping transmission or generation equipments, whose probability of occurrence is relatively large (compared for instance to the three-phase short-circuit considered in angle stability studies). Voltage instability usually starts from a local bus or area, and then may evolve into a wide-area instability problem if it cannot be controlled locally. An extreme type of voltage instability is voltage collapse, in which voltage instability leads to loss of voltage in a significant part of the system. Voltage collapse of a region or even the total system is a possibility. When a power system experiences voltage collapse, system voltages decay to a level from which they are unable to recover. As a consequence of voltage collapse, an area (generally, a load center) of a power system may experience a blackout. Restoration procedures would then be required to restore the blackout area.

Presently, the transmission open access environment has created an economic incentive to operate power systems closer to their security limits. Transmission systems are pushed to transfer more power. Load increases and/or generation rescheduling stress the system by increasing power transfer over long distances and/or by drawing on reactive power reserves. Nevertheless, the construction of new transmission and generation facilities is often delayed and sometimes infeasible due to geographic factors. As a result, transmission networks operate closer to their loadability limits and hence the likelihood of voltage collapse occurring becomes greater. For example, in the past, a power system may have had its power transfer limited due to angle stability considerations. Complex protection schemes and new types of equipment may now be used to extend power transfers beyond these angle stability imposed limits. The resulting increase in power transfer limits can make the system more susceptible to voltage collapse. Accordingly, monitoring and maintaining voltage stability becomes not only more important but also more challenging than ever.

Simulation-based Voltage Stability Assessment

One of the main tasks of voltage stability monitoring is to track how close a transmission system is to its loadability limit. If the loading is too high to keep sufficient margin, voltage control actions have to be taken to relieve the pressure on the transmission system. Still, a problem associated with voltage stability monitoring is that such a limit is not a fixed quantity, but rather depends on the network topology, generation and load patterns, and the availability of reactive power resources. Any of these factors can vary with time due to scheduled maintenance, unexpected disturbances, etc. Therefore, system operators need reliable tools to monitor voltage levels of power systems in real time and assess voltage stability online. Especially during the condition of high transmission loading or a power system disturbance, system operators should be able to predict or detect potentially dangerous voltage drops that can jeopardize system integrity, and take timely corrective control actions to prevent voltage instability and a wide-area blackout caused by voltage collapse.

- Currently, simulation-based Voltage Stability Assessment (VSA) tools are applied to predict and monitor system voltage stability. Those VSA tools can help operators analyze *what-if* scenarios, i.e. foreseeing the next critical contingencies that may cause voltage instability under a specific operating condition. Nevertheless, several factors limit the accuracy of their assessment results:
- Incorrect assessment results may be caused by inaccurate system models. Since those VSA tools are based on simulations, the accuracy of their assessment results also depends on the accuracy of modeling the generation, load, and transmission facilities. Inaccurate models may influence the creditability of simulation results.
- A traditional VSA tool relies on the state estimator to provide a steady-state solution of the current operating condition. Then, it can perform simulations and calculations on selected contingencies. When a power system is under an extreme operating condition, the state estimator may fail to converge and provide such a steady-state solution to the VSA tool.

Even if the operating condition and system models are credibly obtained, accurate voltage stability assessments for a wide variety range of disturbance come with computational burdens. Online implementation poses a high requirement on the time performance of VSA tools. As a result, the number of simulated contingencies has to be limited. Still, there are increasing difficulties in selecting a limited number of critical contingencies to cover possible disturbances. Under the previous regulated environment, operators knew the critical contingencies well based on past experience because system power flow patterns were well known and well studied over time. After deregulation, power systems have experienced increasingly diverse transactions. New power flow patterns and magnitudes have introduced a significant and unpredictable complexity to the power delivery system in ways that the system was not designed to handle. That makes a power system susceptible to more uncertain disturbances.

The above factors pose challenges of obtaining reliable and timely voltage stability assessment results using traditional VSA tools. Inaccurate or delayed assessment results may lead system operators to make incorrect decisions and hence increase the risk of voltage collapse.

Under Voltage Load Shedding

Control actions to mitigate voltage instability and prevent voltage collapse include reactive power compensation, regulation of generator reactive outputs, Control of transformer tap changers, load shedding, etc.

Load shedding is an effective measure to prevent voltage collapse, which is generally taken at the local substation level and incorporated into the protective relays that only use local measurements. Those relays will only be operated when other controls can not mitigate the aggravating situation.

The most common form is to shed load based on the voltage level –Under Voltage Load shedding (UVLS). UVLS schemes are receiving attentions as a means of avoiding voltage collapse. A UVLS scheme is only used when all other means of avoiding voltage collapse are exhausted since load shedding results in high costs to electricity suppliers and consumers. Thus, the timing and effectiveness of UVLS actions against voltage collapse become critically important. Generally, UVLS schemes shed load in pre-defined blocks that are triggered in stages when local voltage drops to various pre-defined degradation levels. In most UVLS schemes, voltage magnitude is the only triggering criteria. Past research has demonstrated that voltage magnitude alone is not a satisfactory indicator of the proximity to voltage instability under all circumstances.

Currently, settings of UVLS are determined by system engineers through extensive network analyses using offline computer simulation tools. Nevertheless, simulated system behaviors do not always coincide with actual measured system responses due to unavoidable data incorrectness and modeling inaccuracy. Developing appropriate settings for the under voltage levels and time delays are challenging problems faced by power system engineers. Inappropriate settings can result in either excessive shedding or failure to detect the need for load shedding.

Voltage Stability Margin

In fact, voltage stability can be assessed by monitoring the system' voltage stability margin, which indicates the ability to supply and deliver active or reactive power without causing voltage collapse. Depending on what is concerned in voltage stability monitoring, voltage stability margin can be defined and estimated for a specific bus, a system interface or an entire area.

Two types of voltage stability margin indices can be estimated:

- ***Contingency-dependent***: this type of margin indices provide the information about how much the current operating condition can be stressed in a concerned direction without causing voltage instability under any of a list of elected contingencies. Traditional VSA tools can be used to provide such margin information.
- ***Contingency-independent***: this type of margin indices do not rely on any assumed contingency and simply estimate system operators regarding how far the current operating condition is away from voltage collapse, which is more effective in online system monitoring.

In actual power systems, the estimation or computation of voltage stability margin may be complicated due to the large number of generators, the widespread applications of capacitor banks, the uncertainty about the dynamic characteristics of system loads, and the variability of the power flow pattern. In addition, voltage control actions, e.g. operations of transformer tap changers, reactive reserves, and generator reactive outputs are all factors influencing voltage stability margin.

Having recognized the importance of real-time voltage stability margin information and limitations of traditional VSA tools, we may ask such a question: can we use only measurement data at the substation level to direct estimate contingency-independent voltage stability margin in real time? That will be quite valuable for system operators in the following aspects:

- Real-time and reliably monitoring system voltage stability since no computational burden or influence from model inaccuracy

- Determining voltage stability control strategies since the margin information in terms of power-flow or load levels may directly suggest the amount of load shedding or reserve to be switched in
- Verifying the effectiveness of voltage control actions since real-time voltage stability margin will reflect any control on the system.

Measurement-based Voltage Stability Monitoring

EPRI aims to develop new methods using only measurement data at the substation level to calculate contingency-independent voltage stability margins in real time, and send the margins information to the control center for operators to monitor the system voltage stability, determine voltage stability control strategies, and verify control effectiveness.

In 2006, EPRI proposed an innovative measurement-based method for voltage stability monitoring and control at a bus, which is either a load bus or the single interface bus to a load area. The method was named "Voltage Instability Load Shedding" (VILS) (Ref.1 and Ref.2). The calculated voltage stability margin is contingency-independent, and can be expressed in terms of the real or reactive power transferred via that load or interface bus. It can help system operators monitor voltage stability and understand how much load needs to be shed in order to prevent voltage collapse at the monitored bus.

EPRI has validated this control scheme using the measured data (DFR) collected during the 2003 voltage collapse event at TVA's Philadelphia, Mississippi substation, as shown in Figure 1 (Ref.3). EPRI has also collaborated with New York Power Authority to validate this method at the substation level using the PMU data collected at East Garden City (EGC) substation, as shown in Figure 2. The previous studies' results showed the advantages on 1) correctly tracking the distance from current operation condition to the voltage instability edge; 2) providing important information regarding the amount of load to be shed; 3) estimating the critical voltage and tracking its change, which is the threshold value for voltage instability.

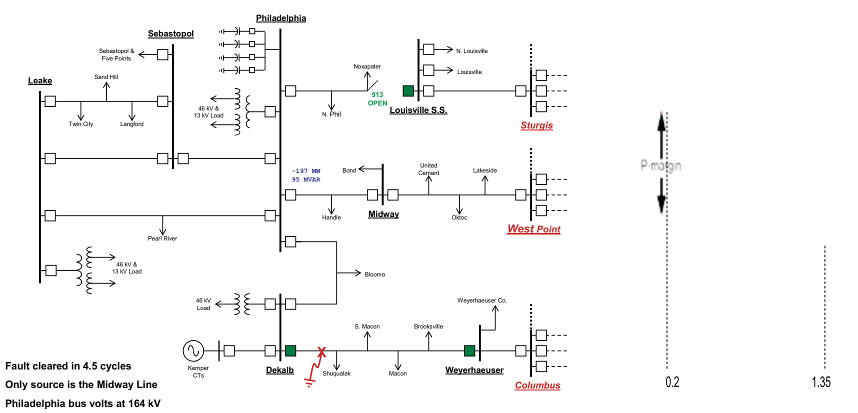


Figure 1-1 Voltage Stability Margin in terms of Active Power

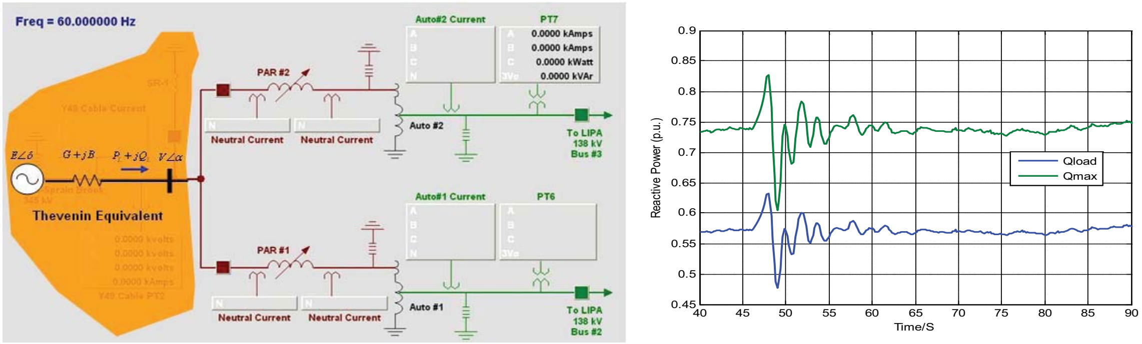


Figure 1-2 Voltage Stability Margin in terms of Reactive Power

Because voltage instability may evolve into a wide-area instability problem, it is important to develop a wide-area voltage stability monitoring method to assess real-time overall voltage stability margin for an entire area. The areas that need to be monitored are generally load centers, whose electricity is supplied by external sources through multiple interface lines. Increasingly, installed PMUs are ideal for monitoring and controlling the dynamic performance of a power system, especially during high-stress operating conditions, and they ensure both the acquirement of accurately synchronized real-time measurement data about voltages, currents, powerflows, etc. The synchronizing capability of PMUs enables the development of wide-area voltage stability monitoring and control schemes.

Based on the VILS method, EPRI has invented a new measurement-based wide-area voltage stability monitoring method using PMUs, which is able to continuously calculate real-time contingency-independent voltage stability margin for an entire load center using PMU measurements taken at its boundary buses (Ref.4). EPRI collaborated with Entergy in 2007 to move this technology toward voltage stability assessment for load centers and examined the feasibility of applying the technology to Entergy's West Region system (Ref.5). An article titled "Entergy and EPRI Validate Measurement-Based Voltage Stability Monitoring Method" has been published in the January 2009 T&D Newsletter (Ref.6). In the article, Sujit Mandal, Senior Staff Engineer at Entergy indicated, "The results of the validation study have shown us here at Entergy that this is promising for enhancing the security of our transmission system."

EPRI works with NYSERDA on this project of Real-Time Applications of Phasor Measurement Units (PMU) to further validate the feasibility of applying this technology to New York system.

Section 2: Project Objectives

The objectives of this project are to demonstrate the new approach developed by EPRI, called the Voltage Instability Load Shedding, to prevent voltage collapse with an automatic safety net or system protection scheme that will automatically shed the right amount of load to arrest an impending voltage collapse by using high-sampling rate digital measurement devices such as Digital Fault Recorder (DFR), PMU or intelligent electronic devices (IED) installed at the substation level. This also demonstrates its ability to provide real-time voltage stability margins that are computed from the real-time data of the DFR, PMU or IED. Such information will be provided to Task 2 for monitoring and visualization.

Section 3: Measurement-Based Voltage Stability Monitoring

Measurement-Based Voltage Stability Monitoring Method Flowchart

A load center (as shown in Figure 3-1) is generally defined as a particular geographical area with a high load demand, which has following characteristics:

- Local generations are inadequate to meet local load demands such that the load center is supplied with electricity by sources from the external system through boundary buses
- Interface lines from the external sources are critical to the load center's stability.

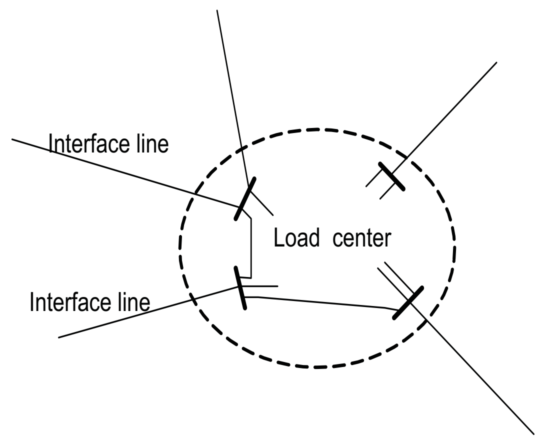


Figure 3-1 Characteristics of a Load Center

Because of those characteristics, load centers are the areas more susceptible to voltage instability.

Figure 3-2 shows the flow chart of the measurement-based voltage stability monitoring method, which has the following steps:

- Obtain synchronized voltage and current measurements at all boundary buses using PMUs
- Determine a fictitious boundary bus representing all boundary buses, and calculate the equivalent voltage phasor, real power and reactive power at this bus
- Estimate the external system's Thevenin equivalent parameters
- Calculate power transfer limits at the interface of the load center using the Thevenin equivalent
- Calculate voltage stability margin in terms of real power and reactive power

In the rest of this chapter, the method will be introduced in detail.

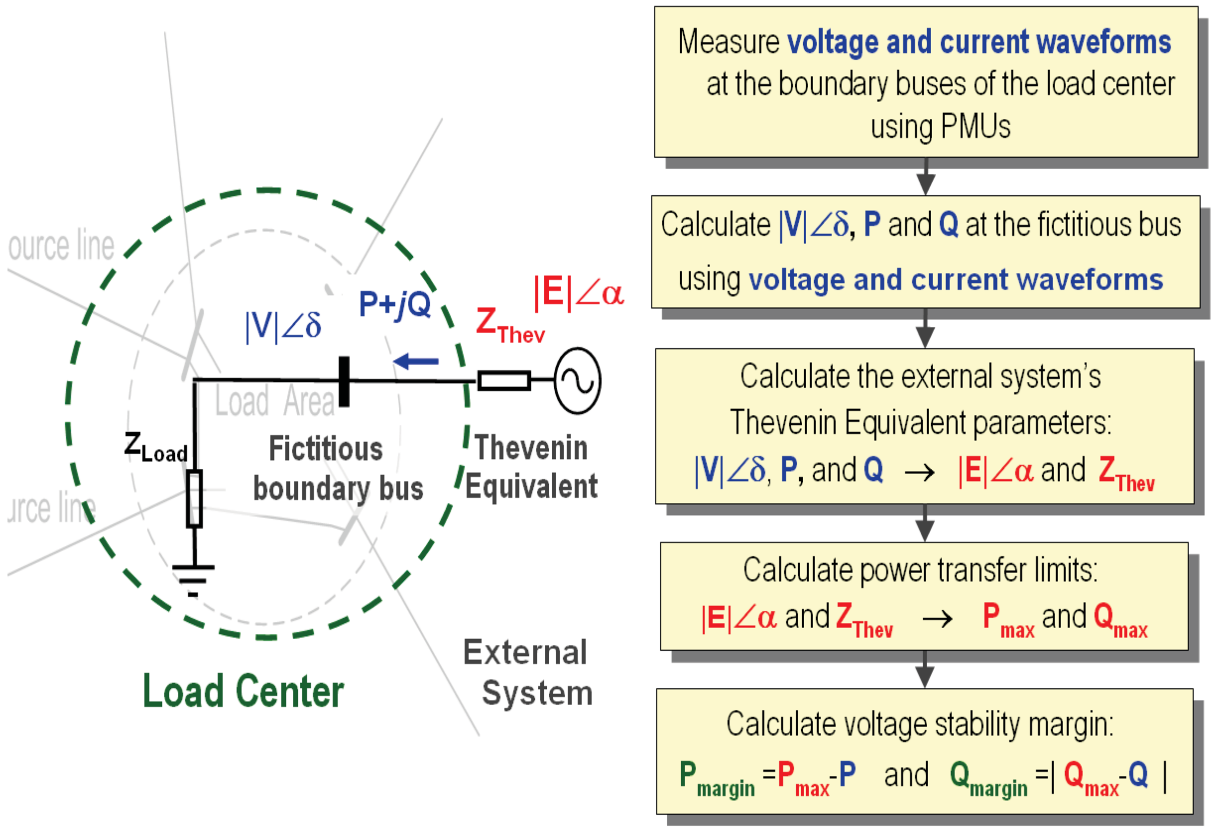


Figure 3-2 Flowchart of the Measurement-Based Voltage Stability Monitoring Method

Measurement-Based Voltage Stability Monitoring Method

Step 1 Equivalent Network for a Load Center

Figure 3-3 represents a power system that is composed of two parts: the load center and the external system. The powers transferred from the external system to the load center can be calculated using the measured current and voltage phasors at these boundary buses.

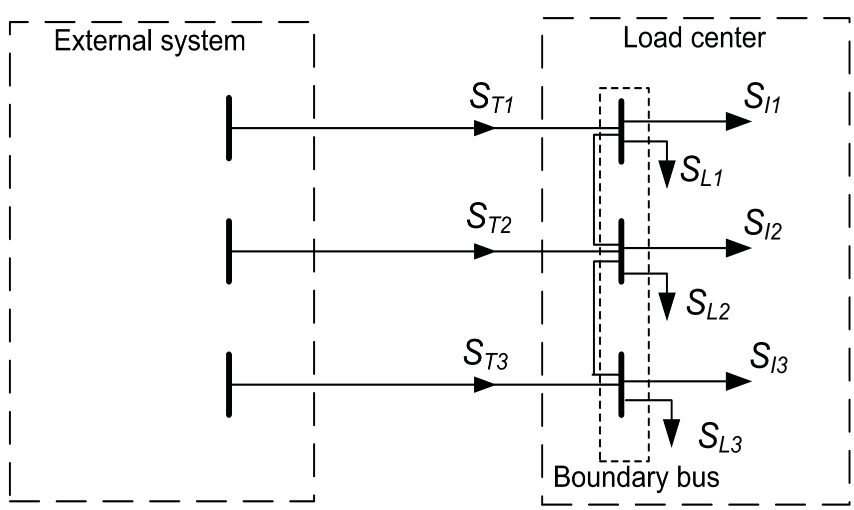


Figure 3-3 Representing a Power System by a Load Center and the External System

S_{Ti} denotes the power transferred from the external system to boundary bus *i*. S_{Li} denotes the local load at boundary bus *i*. S_{Ii} denotes and the power transfer from the boundary bus *i* to the internal part of the load center (not including the boundary buses).

Then, the power transferred to the load center through boundary bus *i* can be calculated by Equation 3-1, where S_i is the sum of the local load at boundary bus *i* and the power transfer from boundary bus *i* to internal part of the load center.

$$S_i = S_{Li} + S_{Ii} \tag{3-1}$$

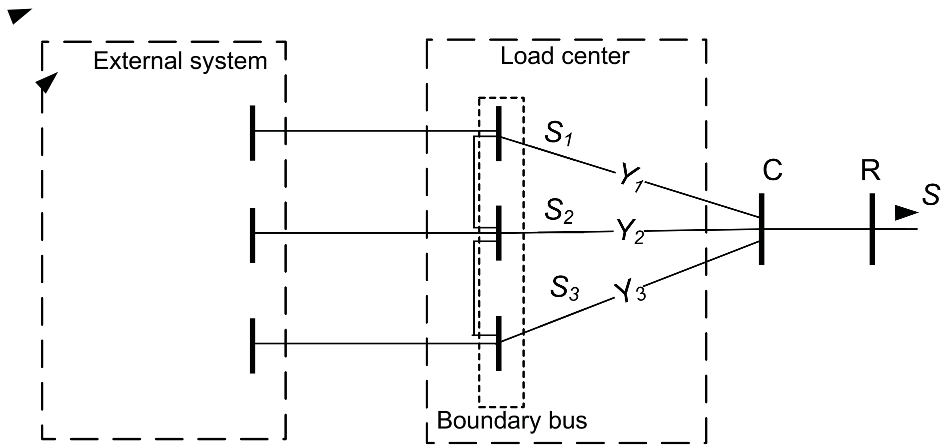


Figure 3-4 Equivalent Network for a Load Center

To simplify the system, the internal part of the load center can be replaced by two fictitious buses, C and R, as shown in Figure 3-4. That equivalent system has the same states seen from the external system. In Figure 3-4, C is a fictitious connection bus and R is a fictitious load bus to represent the load center in Figure 3-3.

Step 2 Theven Equivalent for the External System

Further, the external system can be simplified as a Thevenin Equivalent circuit shown in Figure 3-5. $|E|\angle\alpha$ is the equivalent source voltage and Z_{thev} is the equivalent admittance. V_R is the voltage phasor of the fictitious bus R, which magnitude $|V_R|$ can be used as an index to present the overall voltage level of the control center. P and Q are respectively the total real and reactive powers transferred to the load center.

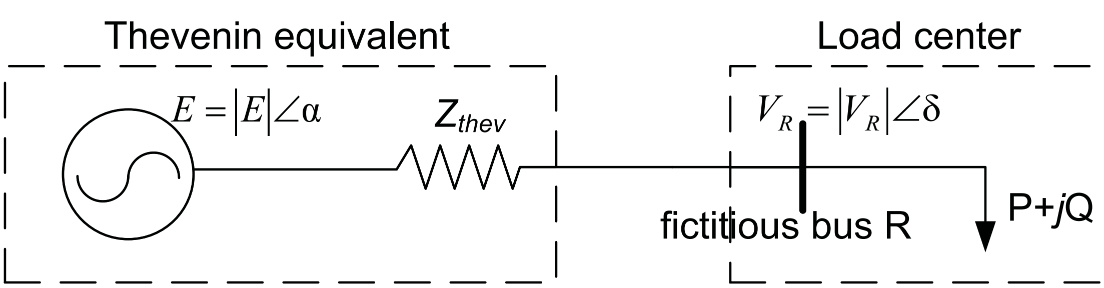


Figure 3-5 Thevenin Equivalent of a System

V_R can be calculated by Equation 3-2, where $S = \sum_{i=1}^{n} S_i$ =P+*j*Q, i.e. the total power transferred to the load center, and V_i is the voltage phasor of boundary bus *i*.

$$V_R = \frac{S}{\sum_{i=1}^{n}(S_i / V_i)} \qquad 3\text{-}2$$

From Figure 3-5, there are

$$E \quad Z_{thev} I_R = V_R \qquad 3\text{-}3$$

where $I_R=(S/V_R)^*$. V_R and I_R can be obtained from measurement data. The equivalent load impedance at fictitious bus R can be calculated by $Z_{load}=V_R/I_R$.

In order to solve E and Z_{thev}, let $E = E_r + jE_i$, $V_R = m + jn$, $I_R = \frac{S^*}{V_R^*} = p + jq$, and $Z_{thev} = R + jX$. Then, Equation 3-3 can be written as:

$$\begin{vmatrix} 1 & 0 & p & q \\ 0 & 1 & q & p \end{vmatrix} \begin{vmatrix} E_r \\ E_i \\ R \\ X \end{vmatrix} = \begin{vmatrix} m \\ n \end{vmatrix} \qquad 3\text{-}4$$

Assume that during any short time window, e.g. 4~10 cycles, Thevenin parameters E_r, E_i, R and X do not significantly change. At least two measurement data points are needed to solve the four variables. Since noise usually exists in measurement data and Thevenin parameters may float, more data points in the time window will help more accurately estimate the Thevenin parameters. The least square approach and Kalman Filter are two optional technologies to estimate Thevenin parameters. Section 2.3 will use Kalman Filter as an example to introduce how to estimate Thevenin parameters. Study results on using the least square approach to estimate Thevenin parameters can be found in Ref. 1.

Step 3 Calculation of Voltage Stability Margin

After Thevenin parameters are estimated, the maximum power (denoted by $S_{max}=P_{max}+jQ_{max}$) transferred to the load center can be calculated accordingly. The real and reactive powers transferred from the external system to the load center can be expressed by Equations 3-5 and (3-6), where $Y=1/Z_{thev}=G+jB$ is the Thevenin admittance, and β is the impedance angle of Z_{thev}.

$$P=|E\ V_R\ Y| \cos(\alpha-\delta-\beta) \quad |V_R|^2 G \qquad 3\text{-}5$$

$$Q=|E\ V_R\ Y| \sin(\alpha-\delta-\beta) \quad |V_R|^2 B \qquad 3\text{-}6$$

According to the characteristics of a P-V curve, when P increases, $|V_R|$ will drop. Voltage instability may happen after a nose point is past. There is a stability limit of $|V_R|$, which can be denoted by $V_{critical}$. Take the derivative of real power P with respect to $|V_R|$ and let it equal 0. Equation 3-7 gives the equation to calculate $V_{critical}$ using measured power factor and estimated Thevenin parameters (E and β). When $|V_R|$ equals $V_{critical}$, P and Q reach their maximum values P_{max} and Q_{max}, which are respectively real and reactive power transfer limits and can be calculated by Equations 3-8 and 3-9. (Please see Ref. 1 for a detailed calculation procedure.)

$$V_{critical} = \frac{|E|}{\sqrt{2\,[1+\cos(\beta)\,]}} \qquad 3\text{-}7$$

$$P_{max} = \frac{|E|^2 |Y| \cos}{2[1+\cos(\beta)]} \qquad 3\text{-}8$$

$$Q_{max} = \frac{|E|^2 |Y| \sin}{2[1+\cos(\beta\,)\quad]} \qquad 3\text{-}9$$

Voltage stability margins in terms of real and reactive power transfers are denoted by P_{margin}, and Q_{margin}, which indicate available power transfer capabilities without causing voltage instability. They can be calculated by Equations 3-10 and 3-11, respectively.

$$P_{margin} = P_{max} - P \qquad 3\text{-}10$$

$$Q_{margin} = |Q_{max} - Q| \qquad 3\text{-}11$$

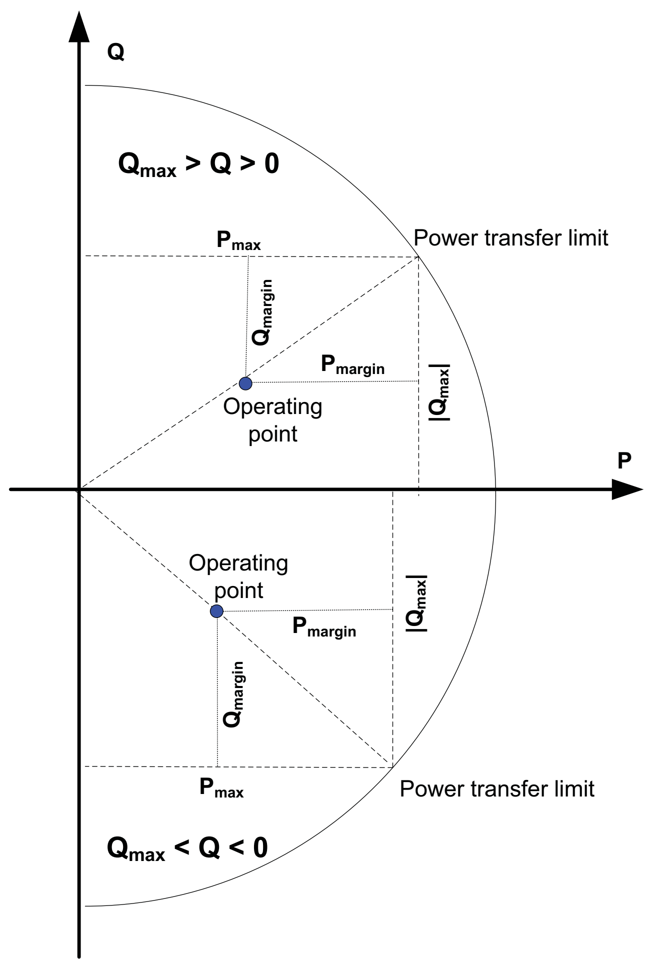


Figure 3-6 Voltage Stability Margins Expressed in the P-Q plane

Figure 3-6 shows the relationships between the power transfer limits and stability margins. The circle drawn in the P-Q plane represents the voltage stability boundary of the operating condition. Its radius is equal to

$$|P_{max}+jQ_{max}|=\frac{|E|^2|Y|}{2[1+\cos(\quad+\beta)]} \tag{3-12}$$

P is the net power transferred to the load center, so it is always positive. Q could be either positive (if the load center also needs reactive power supply from the external system) or negative (otherwise). For the former, the operating condition is in quadrant I; for the latter, the operating point is in quadrant IV. Stability margins P_{margin} and Q_{margin} are respectively the projections of the distance between the current operating point and the corresponding power transfer limit point (at the circle) with respect to the P and Q axes. While the system approaches the voltage stability boundary, the operating point moves toward the voltage stability limit leading to decreasing P_{margin} and Q_{margin}.

It should be noticed that the voltage stability boundary, i.e. the circle, is not fixed because, from (3-12), it is related to the Thevenin Equivalent that represents the rest of the system. Both P_{max} and Q_{max} may dynamically change. For most cases, when the system approaches the voltage stability boundary, P_{max} and Q_{max} will decrease, which means that the size of the circle may shrink.

Estimation of Thevenin Equivalent Parameters

Kalman Filter contains a set of mathematical equations that provides an efficient computational (recursive) means to estimate the state of a process, in a way that minimizes the mean of the squared error.

Assume the estimation equation is:

$$\hat{z} = H\hat{x} + \hat{v} \tag{3-13}$$

where $\hat{z}$ is the measurement vector, $\hat{x}$ is the state vector to be estimated, H is the observation model, and $\hat{v}$ is the observation noise. For the estimation of Thevenin Equivalent parameters, the state vector is

$$\hat{x} = \begin{vmatrix} E_r \\ E_i \\ R \\ X \end{vmatrix} \tag{3-14}$$

From Equation 3-4, use the real and imaginary parts of V_R, i.e. m and n, to form the measurement vector

$$\hat{z} = \begin{vmatrix} m \\ n \end{vmatrix} \tag{3-15}$$

and the observation model is

$$H = \begin{vmatrix} 1 & 0 & p & q \\ 0 & 1 & q & p \end{vmatrix} \tag{3-16}$$

whose elements p and q are real and imaginary parks of I_R and can be real-time updated using the measurement data of I_R.

During a short time window, e.g. 4-10 cycles, assume Thevenin equivalent parameters keep constant, which can be estimated by a recursive calculation process. At time instant k (i.e. the k-th time step), the estimation of state vector $\hat{x}$ can be recursively calculated by the following recursive equation according to the theory of Kalman Filter.

$$\hat{x}_k = \hat{x}_{k \quad 1} + K_k[z_k \quad H_k\hat{x}_{k \quad 1}] \qquad 3\text{-}17$$

where

$$K_k = P_{k \quad 1}H_k^T(H_kP_{k \quad 1}H_k^T + R)^{\quad 1} \qquad 3\text{-}18$$

$$P_k = (I \quad K_kH_k)P_{k \quad 1} \qquad 3\text{-}19$$

P_k is the state vector's estimation error covariance matrix at the time instant k, whose initial value P_0 can be selected according to the probable changes of Thevenin parameters during the time window. R is the measurement error covariance matrix, which can be estimated according to the accuracies of the measurement devices.

New York Transmission System

The New York Independent System Operator (NYISO) manages New York's electricity transmission grid and facilitates the wholesale electric markets in order to ensure overall system reliability. The New York bulk electric transmission system is neighbored by four control areas juxtaposing US and Canadian territories. These areas include ISO-NE (Independent System Operator – New England), PJM (Pennsylvania – Jersey - Maryland), HQ (Hydro-Québec), and IESO (Independent System Operator of Ontario). In addition to using 115 kV and 138 kV transmission systems, the NYISO network includes 230 kV, 345 kV and 765 kV lines.

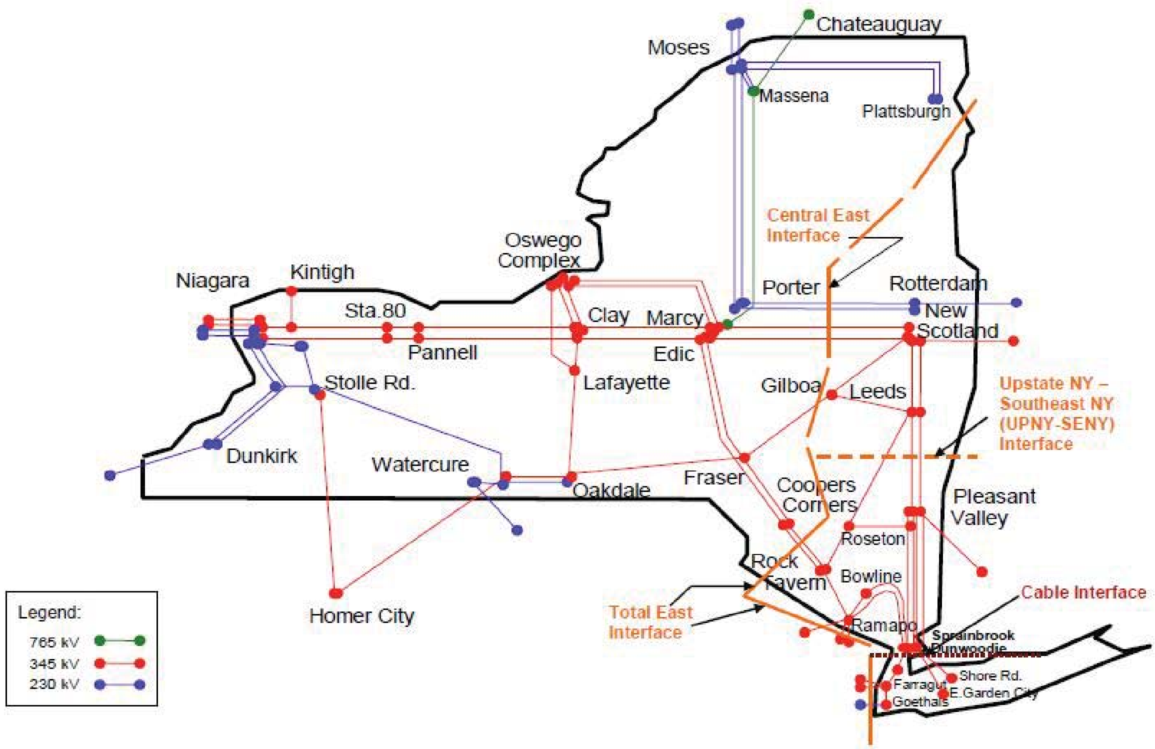


Figure 4-1 NYISO transmission map (230 kV and above) (Ref.7)

The NYISO system exhibits summer peaking characteristics and the 2009 summer coincident peak load is forecast at 33.5 GW (Ref. 8). The New York City metropolitan area (NYC) and Long Island (LI) are areas of concentrated demand. Both localities have requirements for installed generating capacity that are more stringent than the rest of the region, to ensure reliability of service. Among the 11 zones typically used in analyzing this system, these load pockets are located in Zone J (New York City) and Zone K (Long Island). These 'Zones' (Figure 4-2), however, are expressed as 'Areas' in the base case powerflows.

Figure 4-2 New York (NYISO) Electric Regions (Ref. 9)

For the purposes of transfer limit analysis, the NYISO system is typically studied under a number of cross-state interfaces. Similar transfer capabilities are also established between inter-state balancing areas (Ref. 10, Figure 4-3).

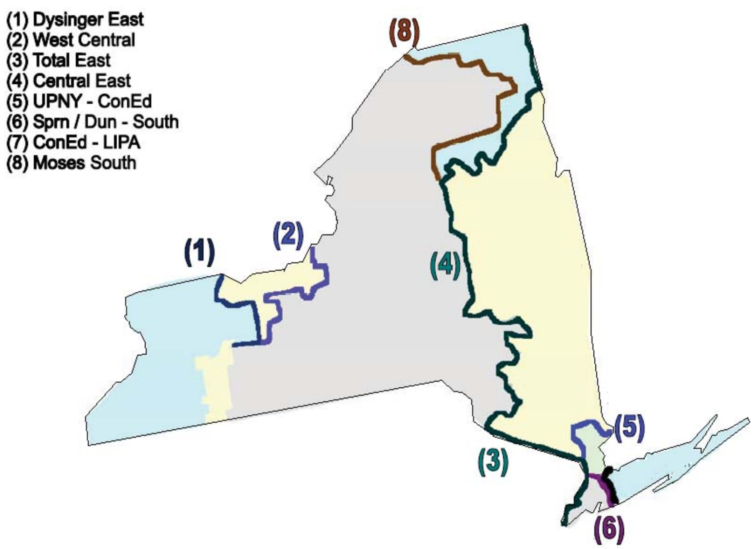


Figure 4-3 Cross-state transfer for thermal capability assessment

For this VCA study, a set of data including powerflow base case, dynamic data, transfer scenarios, and contingency list has been provided by the NYISO.

Powerflow Base Case

The powerflow base case provided for this study are from 2007 series Annual Transmission Baseline Assessment (ATBA) data set and correspond to 2012 summer peak. The file name is CY07-ATBA-SUM12_rev4.raw. Additional information on settings for series/shunt reactors, switchable capacitors and SVC/StatCom was also provided.

There are three shunt compensators in the NYISO system. These are located at the Marcy (79799), Fraser (75402), and Leeds 345kV (78701) stations. The Leeds and Fraser installations are Static VAr Compensators (SVC). The Marcy CSC is modeled in the shunt (STATCOM) mode. These SVCs/FACTS devices are set to zero reactive output pre-contingency and have their full dynamic range of the reactive compensation available post-contingency.

Table 4-1: Powerflow data summary

```
2007 NYISO CLASS YEAR ATBA - REV 4                                SYSTEM SUMMARY
 2012 SUMMER PEAK LOAD W/ PJM 2012 RTEP

 ---------------------BUSES----------------------        -----GENERATION----- ----SHUNTS----- AREAS ZONES OWNERS AREA
  TOTAL  PQ<>0.  PQ=0.  PE/E   PE/Q  SWING  OTHER  LOADS PLANTS MACHNS   WIND  FIXED SWITCHED  USED  USED  USED TRANS
  53196  25005  21372   3111   3032      9    667  31171   6267   7772      0   3096   4883     146   446    22    99
 ------------------AC BRANCHES------------------- 3WIND MULTI-SECTION ---DC LINES--FACTS    X----- SWING BUSES -----X
  TOTAL    RXB     RX    RXT   RX=0.    IN    OUT XFORM  LINES SECTNS 2TRM MTRM VSC DEVS     18137 N3 BFN      20.700
  69730  39426   8252  20389   1663  67028   2702   655     38     80   37    0   0    1     50412 OKLAUN1G    24.000
                                                                                           50422 MOSES3 G    24.000
 TOTAL GENERATION PQLOAD   I LOAD   Y LOAD   SHUNTS  CHARGING  LOSSES    SWING             59994 PNM-DC7     345.00
 MW    716506.2 693558.6   3124.0   1265.2    357.3      0.0  18201.5   3893.0             66450 MT WEST4    230.00
 MVAR  153076.6 195276.4   1395.7   4282.5-143078.8 171539.6 266733.4    973.5             66585 NB WEST4    230.00
                                                                                           67270 WEST  SW    230.00
 TOTAL MISMATCH =    9.68 MVA X------- AT BUS --------X   THRSHZ  PQBRAK BLOWUP  SBASE     67683 KET1-12G    13.800
  MAX. MISMATCH =    0.10 MVA  79591 NIAGAR2E    230.00  0.000100  0.700******  100.0     84033 BERS-1      13.800
   HIGH VOLTAGE = 1.44426 PU   22711 05CORRBR    242.00   ADJTHR  ACCTAP TAPLIM SWVBND
   LOW  VOLTAGE = 0.68289 PU   83802 KD CK MI    13.800   0.0050  1.0000 0.0500  100.0
```

Transfer Scenarios

A total of four cross-state transfer scenarios have been provided by NYISO. These transfers correspond to the following interfaces (i) Dysinger – East (ii) Total –East (iii) Upstate New York – ConEd, and (iv) Dunwoodie – South. The source and sink subsystems are characterized by increase and decrease of generation, respectively (no load increase is considered in the sink subsystem). The detailed participation information is tabulated in Table 4-2.

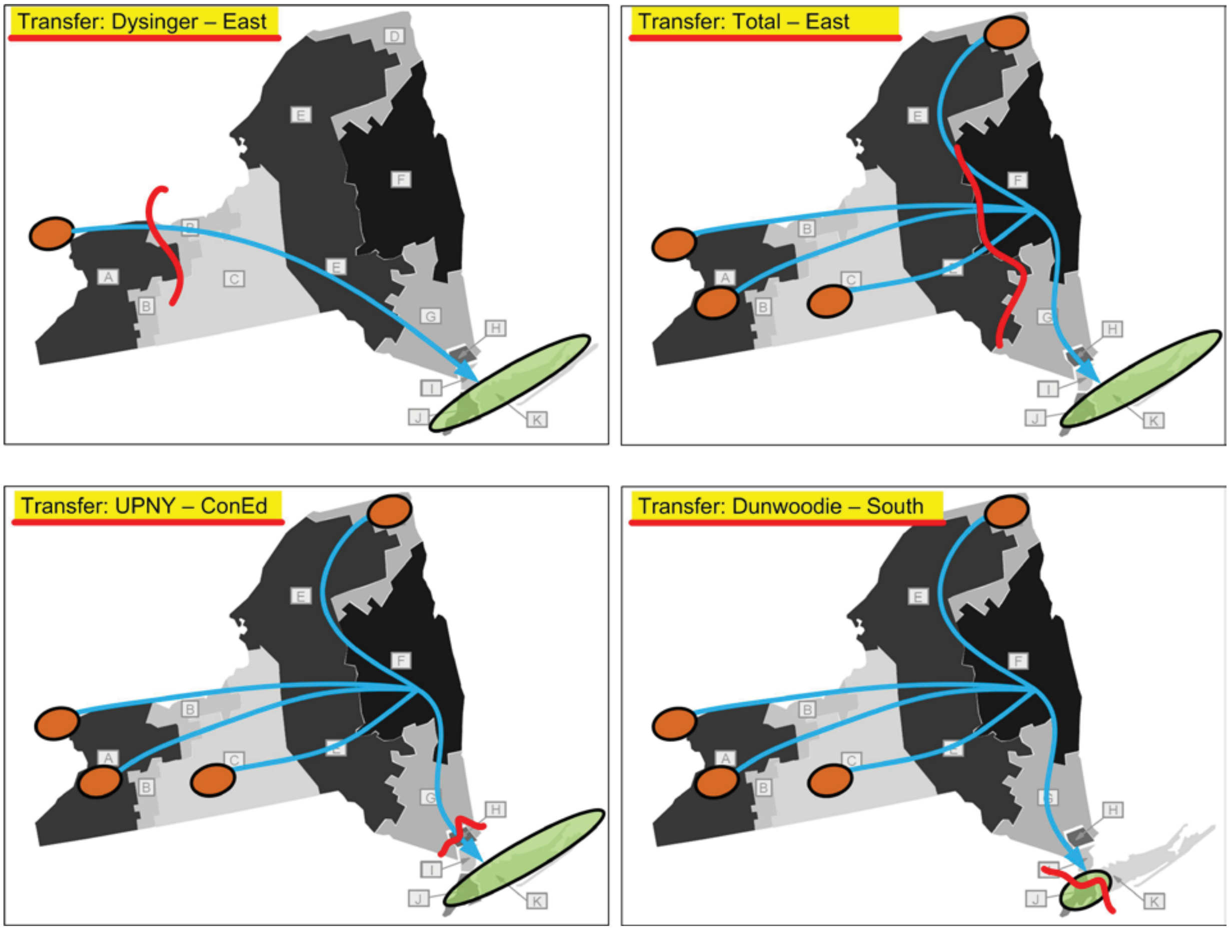


Figure 4-4: Transfers being used in the NYISO VCA study

Table 4-2: Transfer scenarios and status of generating units within the source subsystems

No	Transfer file name (Transfer name)	Source Bus #	Source %	Sink Bus #	Sink %
1	DB2007_dyse.sub (Dysinger – East)	BUS 82765	50	BUS 74906	13
		BUS 81765	50	BUS 74301	3.5
				BUS 74302	3.5
				BUS 74707	20
				BUS 74706	20
				BUS 74705	20
				BUS 74703	20
2	DB2007_te.sub (Total –East)	BUS 76640	5	BUS 74906	13
		BUS 77051	5	BUS 74301	3.5
		BUS 77951	50	BUS 74302	3.5
		BUS 79515	10	BUS 74707	20
		BUS 81765	15	BUS 74706	20
		BUS 81422	15	BUS 74705	20
				BUS 74703	20
3	DB2007_uc.sub (Upstate New York – ConEd)	BUS 76640	5	BUS 74906	13
		BUS 77051	5	BUS 74301	3.5
		BUS 77951	50	BUS 74302	3.5
		BUS 79515	10	BUS 74707	20
		BUS 81765	15	BUS 74706	20
		BUS 82765	15	BUS 74705	20
				BUS 74703	20

4	DB2007_ds.sub (Dunwoodie – South)	BUS 76640 BUS 77051 BUS 77951 BUS 79515 BUS 81765 BUS 82765	5 5 50 10 15 15	BUS 74702 BUS 74707 BUS 74705	40 30 30

Contingencies

The contingencies that are examined in this study correspond to two separate sets (a) steady-state contingencies, and (b) contingencies for dynamic simulation.

For the steady-state contingencies, the predefined contingency set is provided by NYISO and LIPA. The NYISO contingencies are in-line with NERC's planning standard for contingency categories A, B, C, and D. This set includes tower contingencies, generation contingencies, series element contingencies, bus contingencies, stuck breaker contingencies, substation/branch contingencies, HVDC contingencies, inter-area contingencies (PJM) as well as a set of single contingencies and contingencies for new projects (a total of 525 contingencies). The Long-Island (Area 11) contingencies comprise a set of 149 contingencies. This set includes single line outage, multiple line outage, branch outage, and generator tripping.

For the contingency for dynamic simulation, the Table 4-3, below, outlines the most critical/limiting contingencies provided by NYISO for dynamic simulation.

Table 4-3: Contingencies for dynamic simulation

CENTRAL EAST CONTINGENCIES	
CE01	3PH@EDIC 345KV EDIC-N.SCOT#14
CE02	3PH@MARCY345KV MARCY-N.SCOT18
CE03	SLG/STK@EDIC345/EDIC-N.SCOT#14 BKUP CLR@FITZ345
CE04	SLG/NC@EDIC/EDIC-NEW SCOTLAND #14 W/HS&AUTO RCL
CE05	3PH@EDIC 345KV/EDIC-MARCY UE1-7 NORM.CLR
CE06	3PH@MARCY345KV/EDIC-MARCY UE1-7 NORM.CLR
CE07AR	LLG@MARCY/EDIC:MARCY-COOPERS/EDIC-FRASER W/O RCL@EDIC
CE08	LLG @COOPERS ON MARCY-COOPER/FRASER-COOPERS
CE09	SLG/STK@EDIC345KV FITZ-EDIC #FE-1/BKUP CLR@N.SCOT345
CE10	SLG/STK@MARCY345/MARCY-N.SCOT UNS18/STK@MARCY 345
CE11	SLG/STK@FRASER / FRASER-GILBOA & CLEAR SVS
CE14	3PH@ MARCY 345KV VOLNEY-MARCY VU-19 NORM.CLR.
CE15	SLG/STK@MARCY345/VOLNEY-MARCY VU-19/STK@MARCY 345
CE16	SLG/STK@EDIC 345/EDIC-FRASER EF24-40 BACKUP CLEARING CLAY-EDIC #2-15
CE17	SLG/STK @MARCY ON MARCY-COOPERS CORNERS/ CLEAR AT#1
CE20	SLG/STK@EDIC345/EDIC-MARCY UE1-7/CLR PORTER 230&115#4
CE22AR	3PH@EDIC 345/EDIC-FRASER EF24-40 WITH AUTOMATIC RECLOSING
CE24	3PH-NC@FRASER ON FRASER - COOPERS CONRNERS FCC-33
CE99	SLG/STK@SCRIBA 345/SCRIBA-VOLNEY #21 BACKUP CLEARING FITZPATRICKSCRIBA #10
TOTAL EAST CONTINGENCIES	
TE32	3PH@NEW SCOTLAND - 77 BUS
TE33	3PH@NEW SCOTLAND - 99 BUS
UPNY - CONED CONTINGENCIES	
UC04	SLG-STK@BUCH N 345/BUCHANAN N.-INDIAN POINT #2 W95 BACKUP CLEARING BUCHANAN-EAST VIEW-SPRAIN BROOK W93/W79

UC18	3PH@LADENTOWN 345/TWR: LADENTOWN-BUCHANAN S. Y88 AND RAMAPO-BUCHANAN N. Y94
UC25	3PH@RAVENSWOOD #3
UC26	LLG L/O TOWER LADENTOWN-W.HAVERSTRAW /REJ BOWLINE

Dynamic Load Model

The package provided by NYISO includes all the files needed for running dynamic simulations of the 2007 series ATBA Summer Peak Load case, as follows:

- CY07-ATBA-SUM12_rev4.SAV
- 2007_ATBA_29.5.DYR
- MASTER_1.IDV
- CRTCNV.IDV
- FIX-PJM-LI-HVDC.IDV
- NOMOD.IDV
- FIX-MBASE.IDV
- SVC.IRF
- FACTSGEN.IDV
- GNET-1.RSP
- SOLVELF.IDV
- CONL-1.RSP
- MASTER_2.IDV
- HQTE_DYNADC.IRF
- INTFLW.DAT
- INTFLW_CHAN.IRF
- SVCCHAN.IRF
- DCCHAN.IRF
- HVDCLCHN.IRF
- CHANNY.IDV
- MYCLOAD4.BAT
- USRMDL_ALL.OBJ
- SMK202_model.OBJ
- V82BB29_PC.LIB
- G87.LIB
- PSSEWIND.LIB
- CPMATRIX.DAT
- GECPA.DAT
- V82BB_MODEL_PARAMETERS.DAT
- V82BCPMX1.DAT
- V82BCPMX2.DAT

The lumped loads for all buses in New York Area 1-10 are represented by static load model ZIP model in which the real power is modeled as 100% constant current and the reactive power is modeled as 100% constant impedance. From Long Island Power Authority (LIPA) we obtained the dynamic load models for all buses in Area 11 (Long Island). Using the complex load model as defined in PSS/E (Ref. 11), all the lumped loads at every load bus in Area 11 were changed to the structure in Figure 4-4. The load component data at each load bus is the fraction of the MW, which are small-motor (%SM – assumed to be readily stall-able e.g. single-phase residential air-conditioner load), large-motor (%LM - e.g. fans, or 3-phase commercial/industrial etc.), constant current load (%DIS, e.g. discharge lighting etc.), constant power load (%MVA, e.g. typically electronics, plasma TV etc.), transformer saturation (%TEX) and remaining loads (%REM). For all load buses in area 11, we have 50% SM, 0% LM, 5% DIS, 1% TEX, 15% MVA, and 14% REM.

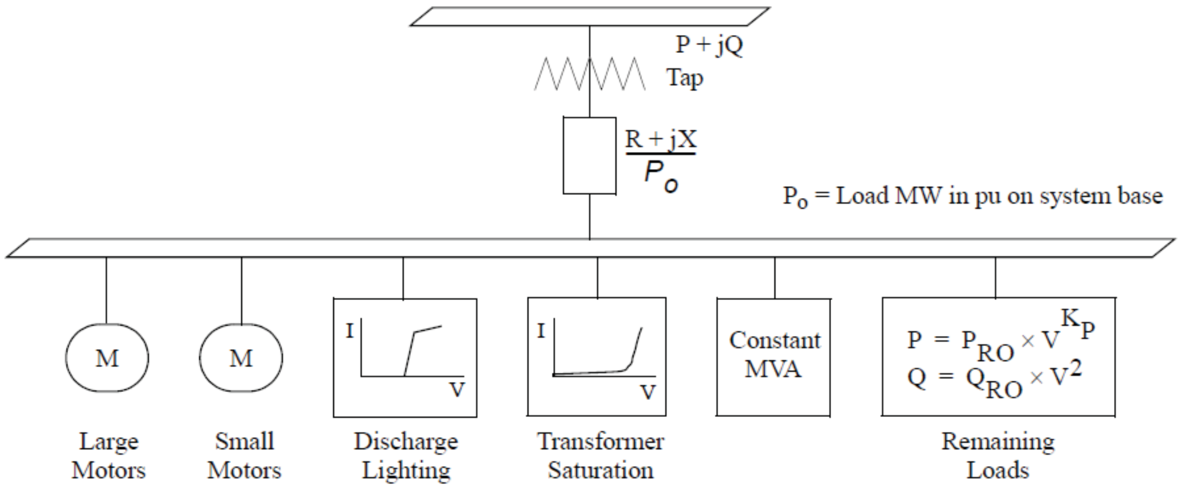


Figure 4-5 PSS/E Complex Load Model Structure

Section 5: Determination of Critical Substations

This section describes an alternative way of determining critical substations related to voltage stability problems. Past experiences of New York transmission planners about the potential interfaces of voltage instability are used to the maximum degree so as to select the most promising substations. We perform steady-state P-V analysis for voltage stability constrained interfaces to determine critical substations. A more intelligent way described in this section is to use visualization tools to display dynamic voltage performance for each scenario to identify voltage control areas that consistently display lower voltages across all scenarios.

By combining the results of the two efforts, we suggest the critical substations to implement the measurement based voltage stability monitoring method and focus on validation study of these substations.

Determining Critical Substations Based on P-V Analysis

Results and observations of recent NYISO voltage stability analysis indicated that the transfer capabilities on the Central East and UPNY-ConEd interfaces were constrained by not only internal New York's system contingencies but also loss-of-source contingencies outside New York's system. These constraints need to be coordinated and evaluated on an interregional basis, which falls well into the objective of this project – Wide Area Power System Analysis and Visualization using PMU. Therefore, we select the Central East and UPNY-ConEd interfaces as the primary interfaces to determine most promising substation where this research focus on for validation study. Appendix 1 of this report includes selected results of the stability analysis, copies of P-V curves, interface definitions and base case assumptions made in developing the various transfer cases.

For the Central East interface, the following critical buses were selected for voltage stability monitoring and analysis purpose:

- NEW SCOTLAND 345 KV
- LEEDS 345 KV
- EDIC 345 KV
- ROTRDM 230 KV
- INGHAM 115 KV
- GRAND IS 115KV

For the UPNY-ConEd interface, the following critical buses were selected for voltage stability monitoring and analysis purpose:

- FARRGUT 345KV
- GOETHALS 230KV
- SPRAINBROOK 345 KV
- DUNWOODIE 345
- MILLWOOD 345
- WEST 49th St 345 KV
- PLEASANT VALLEY 345 KV
- EAST FISHKILL 345 KV

- RAMPO 345 KV
- NEWBRIDGE 345KV
- JAMAICA 138 KV
- CORONA 138 KV
- GREENWOOD 138 KV
- EAST 179th St 138 KV
- ASTORIA EAST 138 KV
- ASTORIA WEST 138 KV
- SHOREHAM 192/138KV
- NRTHPT P 138KV

Determining Critical Substations Based on Visualization Tools

Dynamic analysis is employed in the further study of power system stability to reveal system trajectory after a disturbance. In contrast to static analysis in which equilibrium points of a P-V curve are not time-dependent, dynamic analysis results reveal the transient and the dynamic voltage recovery performance of a power system under study. Visualization tools are used here to help planners to digest the dynamic simulation results. We use color scaled contour map to:

- Visualize transmission voltage profiles for each scenario to identify voltage control areas that consistently displaying lower voltages across all scenarios
- Visualize dynamic voltage recovery performance (1 second after clearing the fault) for each contingency to identify voltage control areas that consistently display lower voltages across all contingencies

Figure 5-1 shows the voltage profiles for the 2012 summer peak at the normal condition. The color scale ranges from deep blue for 0.95 p.u. voltages to deep brown for 1.08 p.u. voltages. Figure 5-2 shows the dynamic voltage recovery performance at one second after tripping the 345 kV lines Marcy T1-Coopers Corner and Fraser-Coopers Corner. These figures indicate that Watercure Substation and Vicinity and the North of the Capital District areas consistently displaying lower voltages.

Recommendation for Critical Substations to Implement Measurement Based Voltage Stability Monitoring Method

By combining the results of the two efforts, we suggest to focus on the North of the Capital District area, which is at the receiving end of the Central East interface, to implement and validate the measurement based voltage stability monitoring method. The following critical buses are suggested:

- NEW SCOTLAND 345 KV #77
- NEW SCOTLAND 345 KV #99
- ROTRDM 230 KV
- INGHAM 115 KV
- GRAND IS 115KV

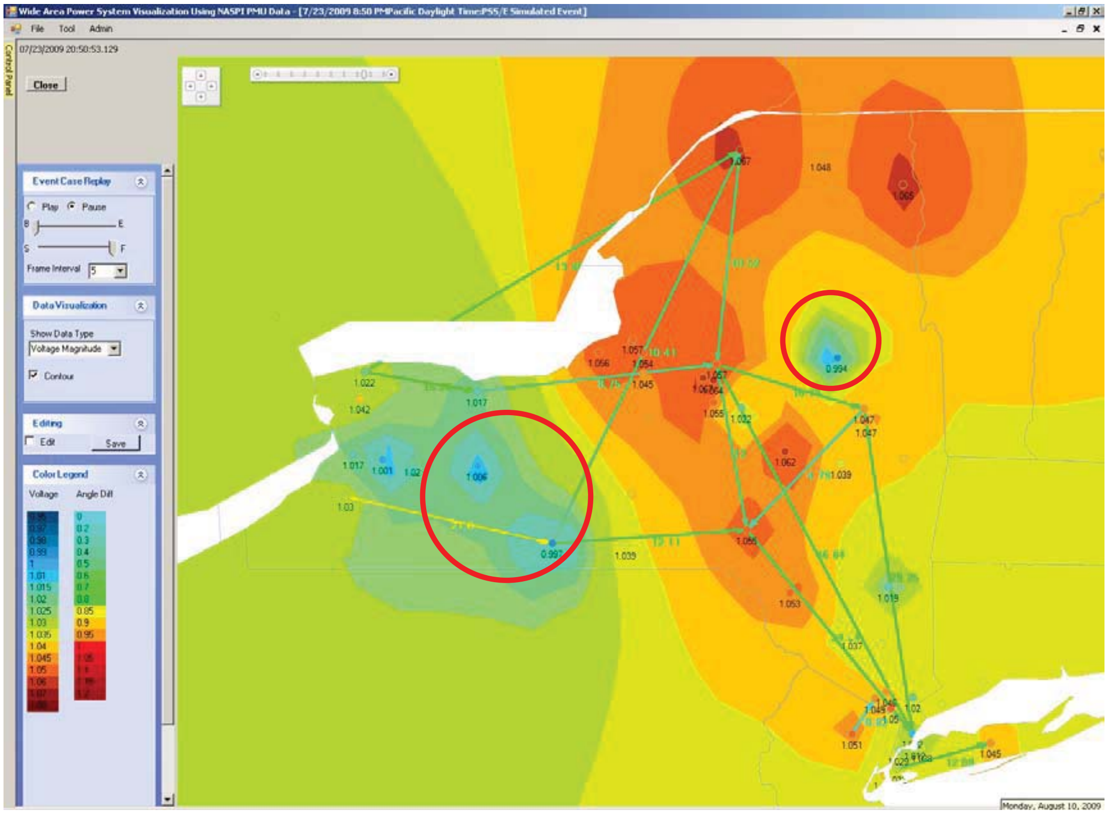


Figure 5-1 NYS Voltage Performance at Normal condition: 2012 Summer Peak Base Case

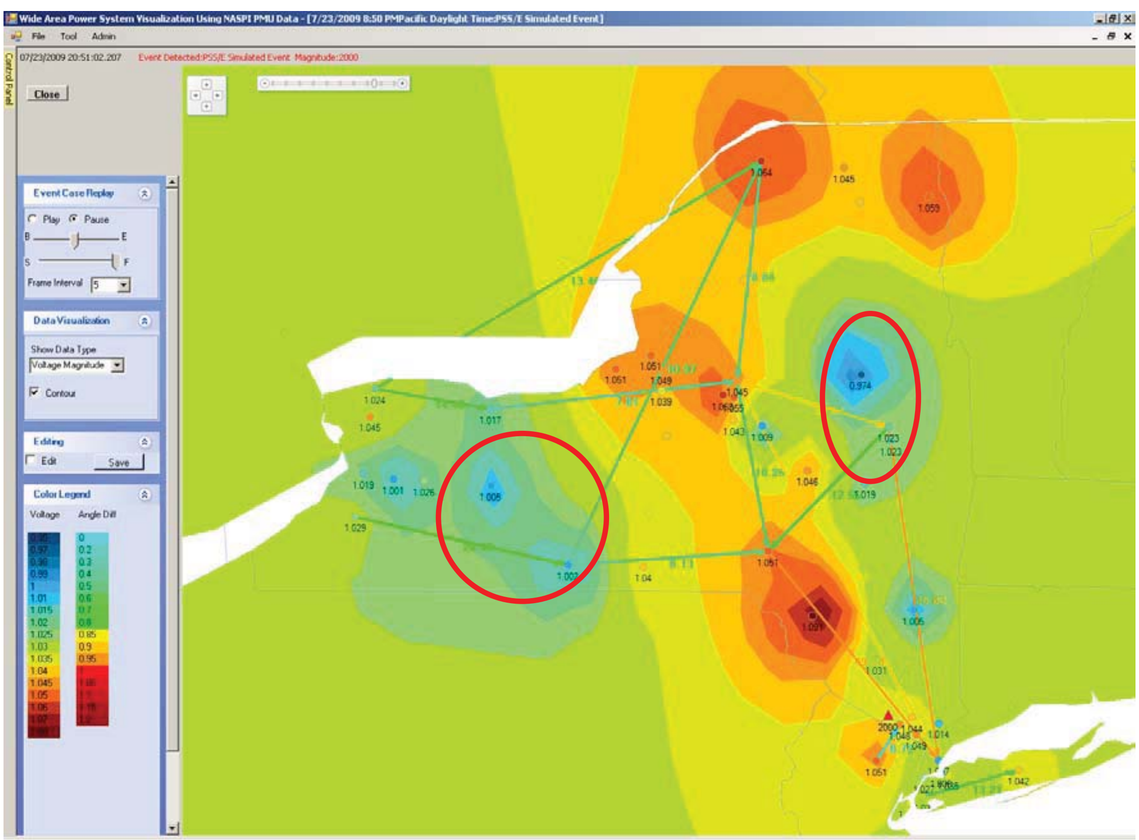


Figure 5-2 NYS Voltage Performance at one second after tripping the 345 kV lines Marcy T1-Coopers Corner and Fraser-Coopers Corner

Section 6: Validation Study of the Method

This section describes the validation study results through the collaboration research with New York ISO and Transmission Owners.

Critical Substations

Five critical substations that have been determined in the last section are shown in Figure 6-1, and seven interface lines are transferring power to the capital area through these five critical substations. It is assumed that PMUs are installed at these five substations to monitor their voltage phasors and the current phasors on the seven interface lines. We examine the feasibility of the proposed measurement-based voltage stability monitoring method on the Central East Interface of the New York system using pseudo PMU data generated by time-domain simulation.

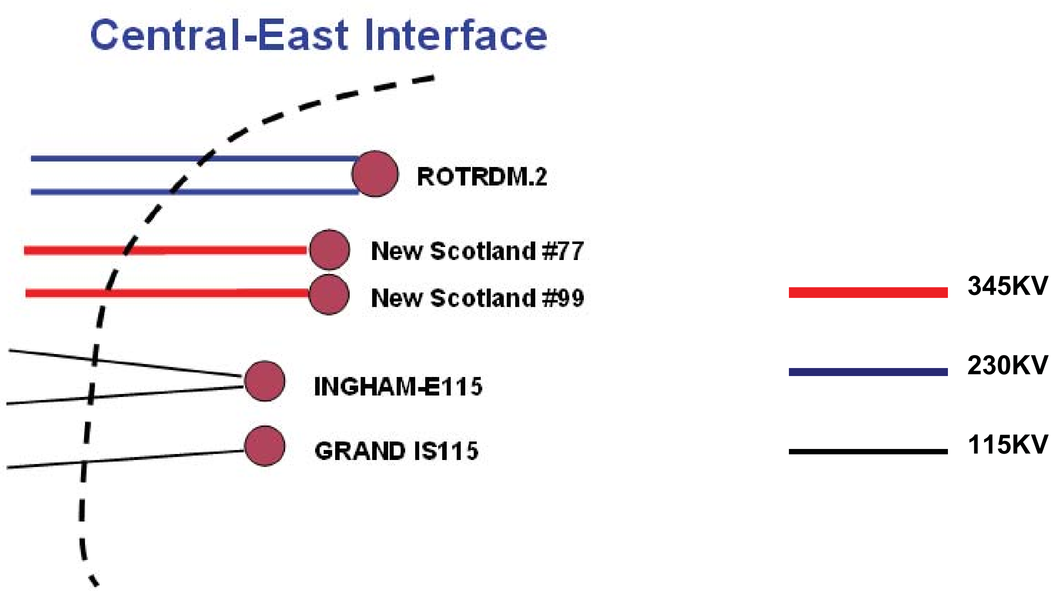


Figure 6-1 Central East interface and critical substations to be monitored

Dynamic Voltage Recovery Performance

In order to capture motor dynamics during the disturbance, the loads in the New York system were represented on the secondary side of the distribution transformer and modeled as 35% static and 65% induction motor. It should be emphasized that the results presented here in no way are indicative of the actual system behavior of all load buses in NYS. What has been done in the next is purely an academic exercise to illustrate the sensitivity of the system dynamic response to various variations percentage of induction load model. The message we want to deliver is that the detailed dynamic model and the regional transient voltage recovery criteria are very important to prevent a voltage instability problem.

We perform the study using the 2012 summer peak case and focus on the contingency - LLG @MARCY/EDIC ON MARCY-COOPER & FRASER-COOPER DBL CKT. The fault is introduced 6.5 cycles after the simulation start. After four cycles, the fault clears by tripping the 345 KV lines from Marcy to Cooper and from Fraser to Cooper. Sensitivity studies are performed to investigate the relationship between voltage recovery and the percentage of induction motor load. Three scenarios are created:

- Scenario 1 – ZIP Load Model for all loads in NYS;
- Scenario 2 – 65% induction motor load for all loads in NYS;
- Scenario 3 – 75% induction motor load for all loads in NYS.

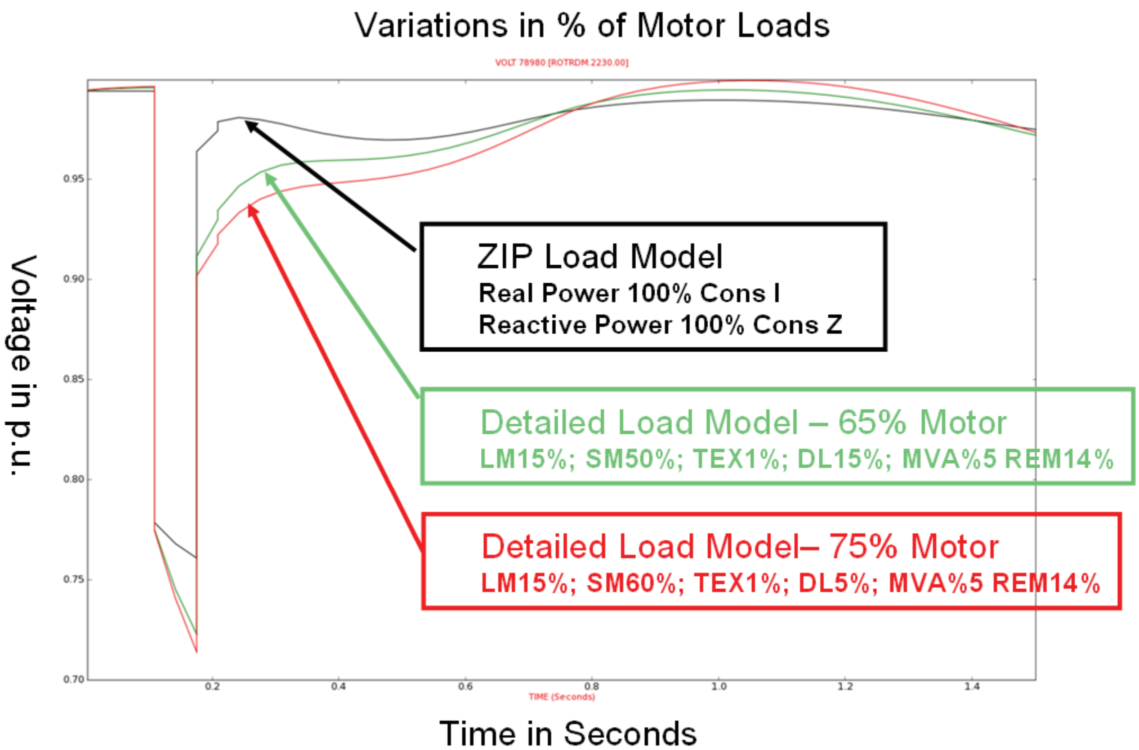


Figure 6-2 Rotterdam 230 KV bus voltage performance vs. different percentage of induction motor load

Figure 6-1 shows that the Rotterdam 230 KV bus voltage recovers simultaneously when the fault clears if all loads are modeled by ZIP load model. Voltage recovery is influenced by the percentage of induction motor load. The higher the percentage of induction motor load, the longer the bus voltage recovers after the fault clearing. The Rotterdam 230 KV bus voltage recovers to 0.95 p.u. in six cycles after the fault clearing if all loads are modeled with 65% induction motor load. The Rotterdam 230 KV bus voltage recovers to 0.95 p.u. in 30 cycles after the fault clearing if all loads are modeled with 75% induction motor load.

Even with a very high percentage of induction motor loads, the Rotterdam bus voltage still can recover quickly to 0.95 p.u.. It indicates that there are enough fast reacting reactive resources (dynamic VAR sources) in NYS. It should be noted that percentage of induction motor load is just one aspect that affects the dynamic voltage recovery. Percentages of distribution impedance, breaker clearing time, etc also influence the dynamic voltage recovery. NERC White Paper on Delayed Voltage Recovery (Ref. 12) has suggested the study methodology and solutions. The white paper states that fault induced delayed voltage recovery events become increasingly probable with continuing market penetration of low-inertia air conditioning loads without compressor under-voltage protection. A more detailed dynamic load model is needed to investigate dynamic voltage recovery behavior more accurately. This leads to another research topic – Dynamic Load Modeling. We refer to some EPRI materials for further reading (Ref. 13 and Ref. 14).

Case Studies

Power-Voltage (PV) analyses are performed for the base case and a list of contingencies. The maximum transfer capability is about 2850 MW for the base case. For the conditions and contingencies tested, The Central East Pre-Contingency Maximum Transfer appears to be approximately 2,600 MW. TWR 41&43 contingency (Tower contingency -Marcy-Coopers Corners #41 and Fraser-Coopers Corners #43 345 kV lines) is the most limiting voltage contingency.

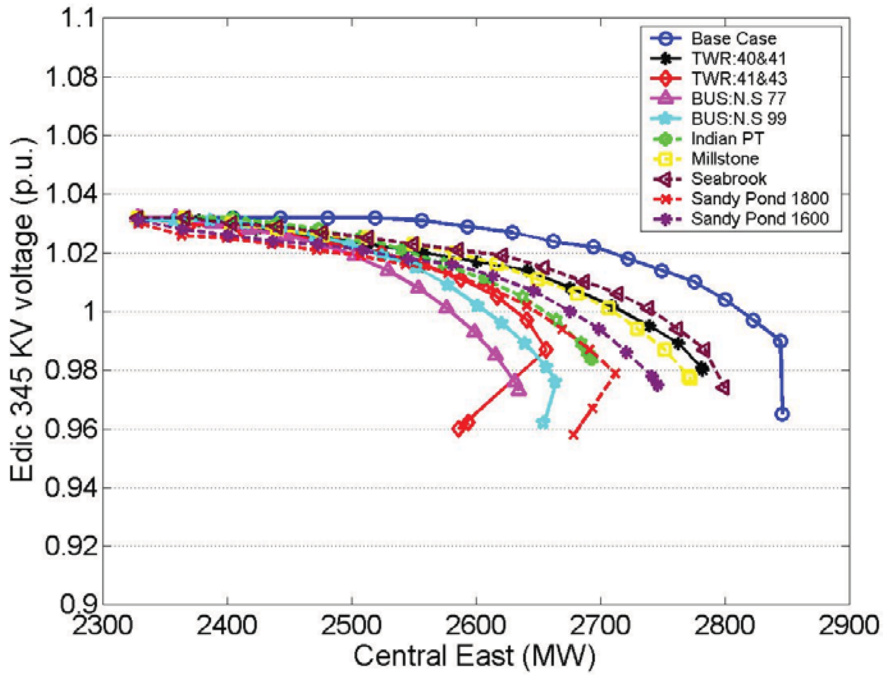


Figure 6-3 Edic Voltage Performance vs. Central East Pre-Contingency Power Flow

Since PMUs are not currently installed at these five substations, we work with NYISO planners to obtain a power-flow base case and dynamic data. We use PSS/E to perform time-domain simulations to obtain the voltage and current waveforms at those substations as pseudo PMU data.

The following two contingencies are used to validate the method:

- CE08: LLG@Coopers Corners, L/O Marcy-Coopers Corners (UCC2-41) & Fraser-Coopers Corners (#33)
- CE08 & UC04: LLG@Coopers Corners, L/O Marcy-Coopers Corners (UCC2-41) & Fraser-Coopers Corners (#33) & SLG/STK@BUCH N 345/BUCHANAN N.-INDIAN POINT #2 W95

Scenario 1 - CE08

The load in this model for the Central East interface is 2550 MW at the beginning of the simulation. The following events are modeled in the dynamic simulation:

1. Double phase to grand fault on the Coopers Corners 345 KV bus, Marcy - Cooper 345 KV Line tripping and Fraser – Cooper 345 KV Line tripping in four cycles.
2. Increase the Central East interface transfer by increasing loads in Capital area proportionally at t=6.3s and at t=11.3s.

The results of the dynamic simulation are shown in Figure 6-4. In this figure, the positive sequence voltages at five critical substations are plotted on the Y-axis and time is shown on the X-axis. From the results, it can be observed that the voltages at these five critical substations drop immediately after the Marcy – Cooper 345 KV line and the Fraser – Cooper 345 KV line opened. The voltages, however, still can maintain above 0.95 p.u. with dynamic Var supports from the fast reacting reactive resources in the Capital area and vicinity. At t=6.3s, we increase the Central East interface flow by increasing the loads in the capital area. The fast voltage collapse occurs immediately. The dynamic Var supports have been used up and there are not enough fast reacting reactive resources available to recover the voltages to normal value.

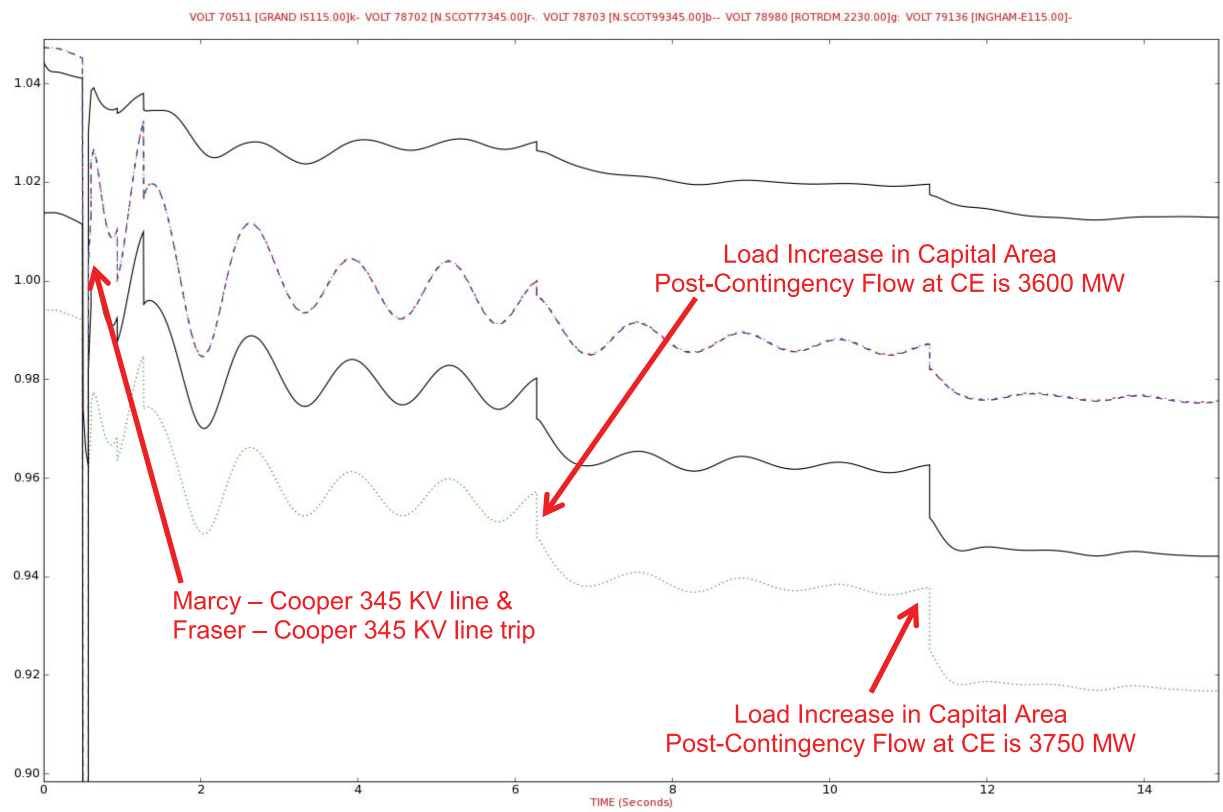


Figure 6-4 Positive sequence voltages at five critical substation as recorded in PSS/E simulation (CE08)

The first validation is to verify the theoretical condition as shown in Figure 3-4 and Figure 3-5. Maximum power transfer is reached when the apparent impedance of the fictitious bus reaches the Thevenin impedance. Figure 6-5 shows the change in the fictitious bus apparent impedance and the Thevenin impedance seen from the five critical substations to the system. The load increase at the time 6.3s is evident by a decreasing load impedance profile at the fictitious bus. It can be observed that two impedances come together at the point of voltage collapse.

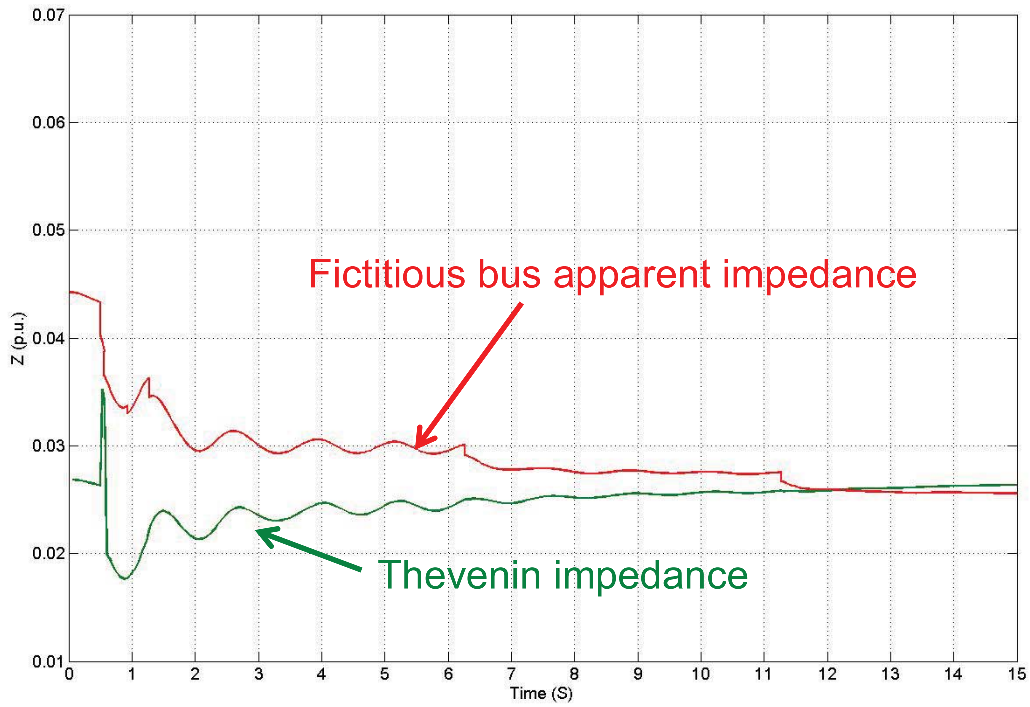


Figure 6-5 The estimated Thevenin impedance and the load impedance at the fictitious load bus (CE08)

The second validation is based on Equation (3-7), which implies that, at the point of voltage collapse, the fictitious bus voltage is equal to the voltage drop at the Thevenin equivalent bus. Figure 6-6 shows the results. The top red curve is the fictitious bus voltage and the bottom green curve is the calculated critical voltage that indicates the voltage magnitude at the collapse point.

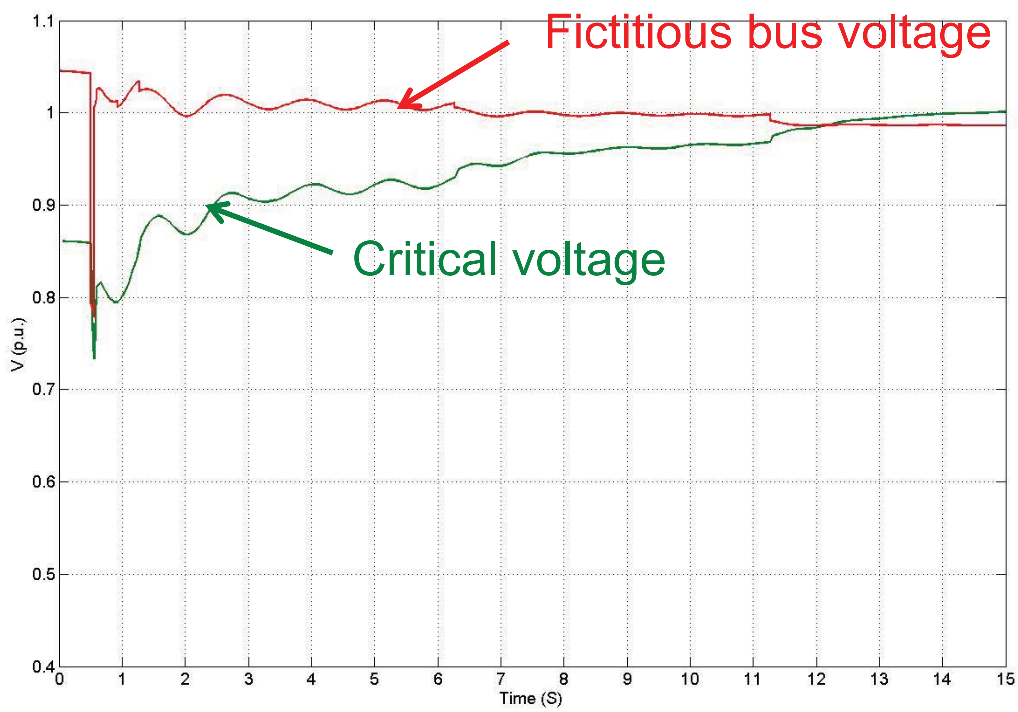


Figure 6-6 The Voltage at the fictitious load bus and the critical voltage (CE08)

Since that the first two validations are based on the fictitious bus that is the equivalent bus of five critical substations. The fictitious bus does reflect the voltage stability condition on the Central East interface but doesn't have physical meaning. Therefore, we have the third and the most important validation that is based on Equation (3-8) ~ (3-11). The maximum power transfer limit can be calculated based on the estimated Thevenin equivalents. Meanwhile, the actual Central East interface flow can be calculated directly from measured voltage and current phasors at five critical substations. The difference between the maximum power transfer limit and actual Central East interface flow is called the voltage instability margin that can be expressed in real and reactive power. The margin information are shown in the Figure 6-7 and Figure 6-8.

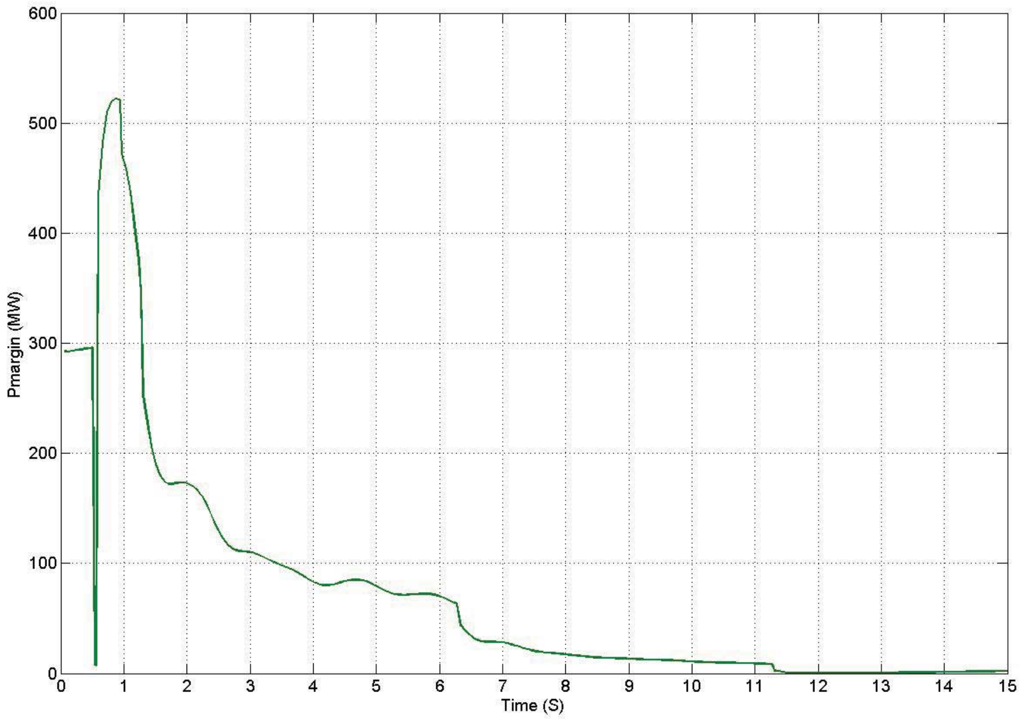


Figure 6-7 Voltage stability margin P_{margin} with respect to real power transfer (CE08)

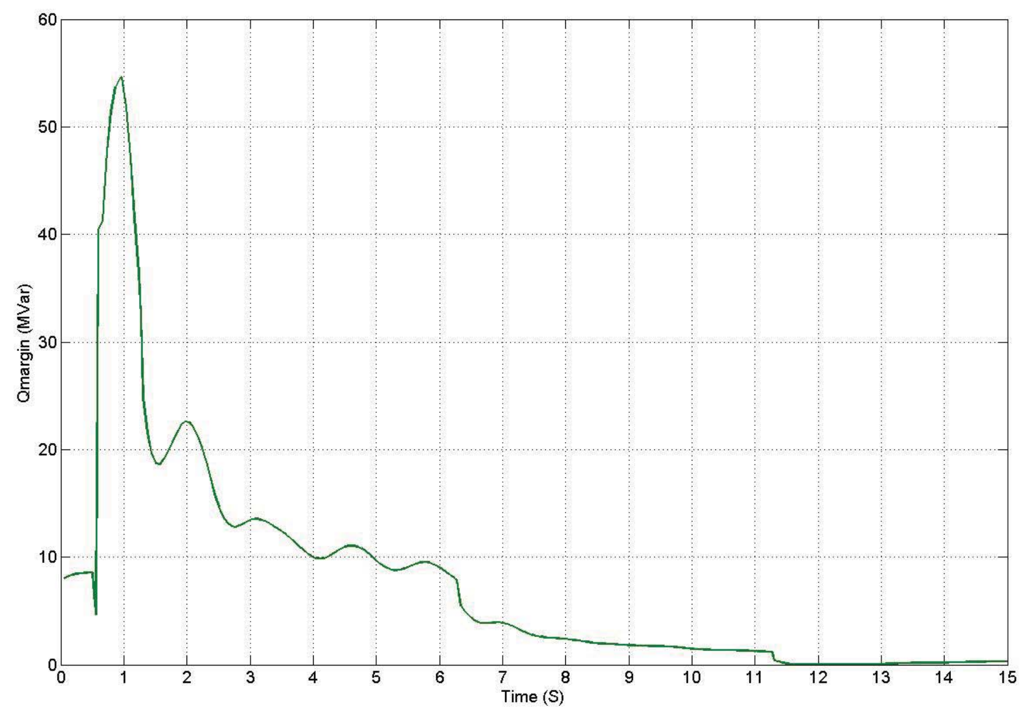


Figure 6-8 Voltage stability margin Q_{margin} with respect to reactive power transfer (CE08)

It can be observed that:

1. At the beginning of the simulation, the voltage stability margin in real power is close to 300MW as shown in Figure 6-7, which means that the maximum transfer capability is approximately 2850 MW. This can be verified by the P-V analysis.
2. From 0.5s to 6.3s, after the Marcy-Cooper 345 KV line and Fraser-Cooper 345 KV line tripping, the voltage stability margin in real power continues decreasing till 80 MW. The voltage stability condition continues deteriorating and the system is close to voltage instability. Similar phenomena can also be observed from the reactive power margin according to Figures 6-8 and the margin drops below 10 MVar at 6.3s.
3. From 6.3s to 11.3s, we further increase the Central East interface flow and push the system to voltage collapse point to see if our method can effectively detect the voltage collapse point. The voltage stability margin in real power drops below the voltage stability margins in real power drops below the pre-setting threshold (25 MW) at 7s. The voltage collapse occurs.

The threshold we are using here is 1% of the pre-contingency transfer on the Central East interface (2550MW). Please note that this is a very aggressive threshold setting and the purpose is to test if our method can effectively and accurately detect the voltage collapse point. For the future application in NYS, we would suggest to use the NYISO 10% margin as the threshold setting. The NYISO stability transfer limit, obtained from a stable simulation of the most severe contingencies, is obtained by reducing the test level of the interface in question by the larger of either 10% of the pre-contingency transfer on the interface, or 200 MW.

Scenario 2 - CE08 & UC04

The load in this model for the Central East interface is 2550 MW. The following events are modeled in the dynamic simulation.

1. Double phase to grand fault on the Coopers Corners 345 KV bus, Marcy - Cooper 345 KV Line tripping and Fraser – Cooper 345 KV Line tripping in four cycles.

2. Single phase to grand fault on Buch N 345 KV, IND PT2 Unit 2 dropping, IND PT2 22KV and 345 KV buses disconnecting, and Buch N – E View 345 KV line tripping in 10.5 cycles; E View 345 KV bus disconnecting in 12.5 cycles.

The results of the dynamic simulation are shown in Figure 6-9. It is similar to the first scenario. The voltages at these five critical substations drop immediately after the Marcy – Cooper 345 KV line and the Fraser – Cooper 345 KV line opened. The voltages still can maintain above 0.95 p.u. with dynamic Var supports from the fast reacting reactive resources in the Capital area and vicinity. At t=7s, we drop the IND PT2 Unit #2 1080MW. The fast voltage collapse occurs immediately.

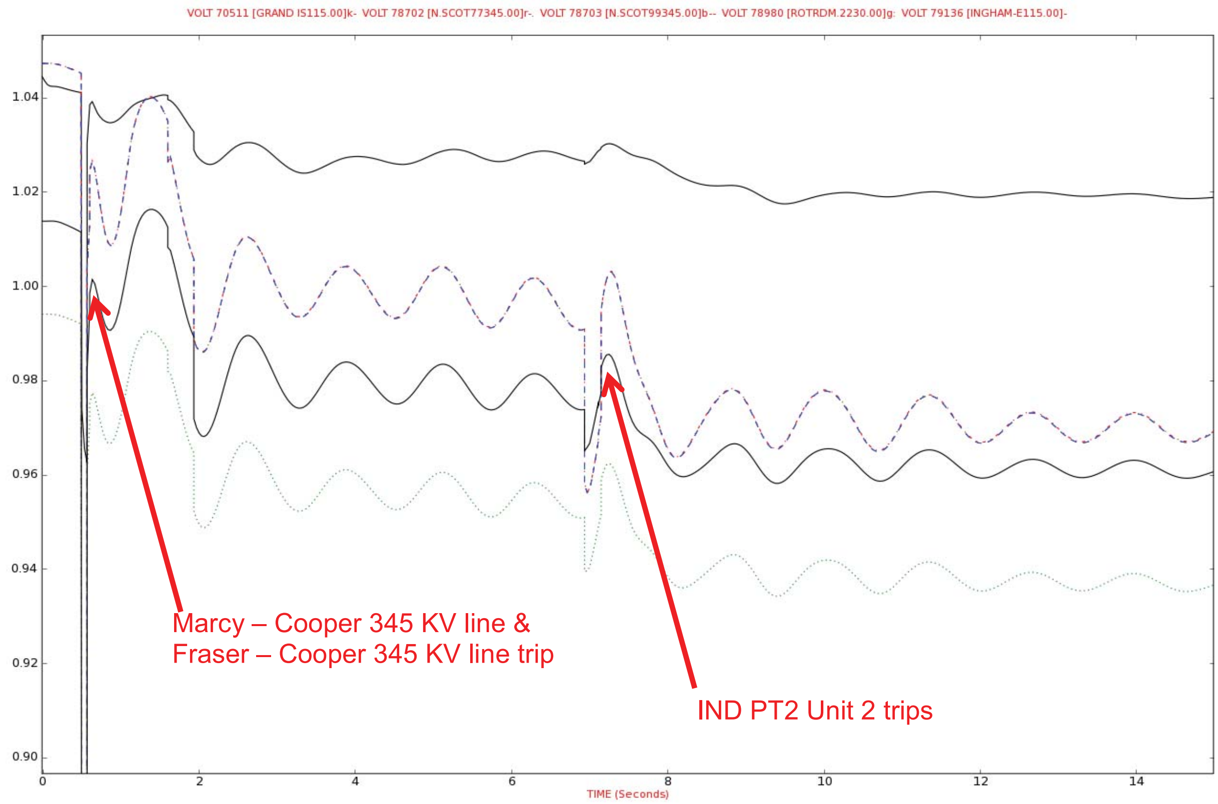


Figure 6-9 Positive sequence voltages at five critical substation as recorded in PSS/E simulation (CE08 & UC04)

We can verify the Equation (3-7), which implies that at the point of voltage collapse the fictitious bus voltage is equal to the voltage drop at the Thevenin equivalent bus. Figure 6-10 shows the results. The top red curve is the fictitious bus voltage and the bottom green curve is the calculated critical voltage that indicates the voltage magnitude at the collapse point.

Figure 6-10 shows the change in the fictitious bus voltage and the critical voltage calculated by our method. The line tripping at the time 0.5s and load increase at the time 6.3s are evident by a decreasing fictitious bus voltage that is the equivalent bus of five critical substations. It can be observed that the fictitious bus voltage hits the critical voltage at the point of voltage collapse.

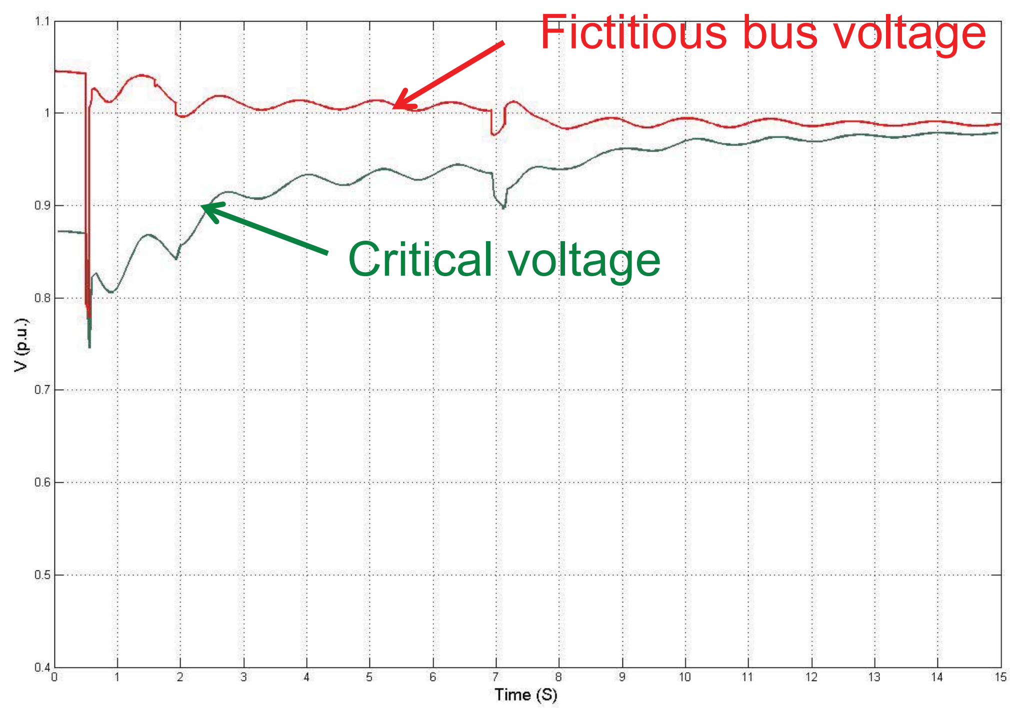


Figure 6-10 The Voltage at the fictitious load bus and the critical voltage (CE08 & UC04)

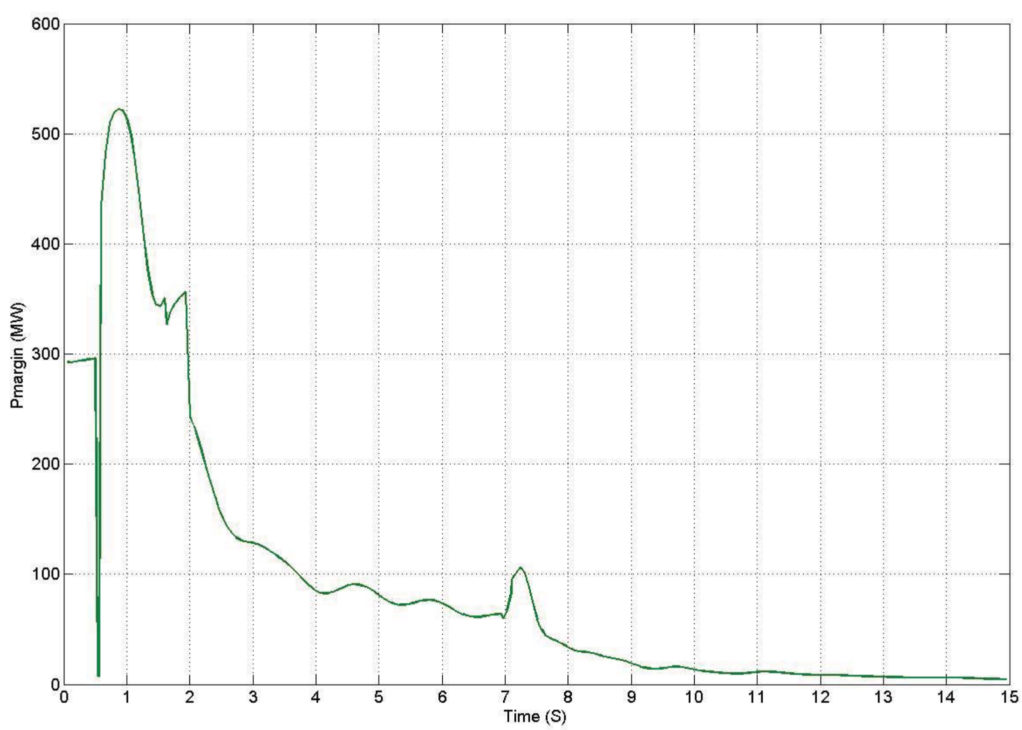


Figure 6-11 Voltage stability margin P_{margin} with respect to real power transfer (CE08 & UC04)

We then take a look at the voltage stability margin in real power, as shown in figure 6-11. It can be observed that:

1. At the beginning of the simulation, the voltage stability margin in real power is close to 300MW, which is the same as the first scenario. This also means that the maximum transfer capability is approximately 2850 MW. This can be verified by the P-V analysis.
2. From 0.5s to 7s, after the Marcy-Cooper 345 KV line and Fraser-Cooper 345 KV line tripping, the voltage stability margin in real power continues decreasing till 80 MW. The voltage stability condition continues deteriorating and the system is close to voltage instability but still stable with dynamic Var supports from the fast reacting reactive resources in the Capital area and vicinity.
3. At 7s, we drop the IND PT2 Unit #2 1080MW. The dynamic Var resources have been used up and there are not enough fast reacting reactive resources available to support the voltage. The voltage collapse occurs immediately.

Section 7: Conclusion and Future Work

Conclusion

The Measurement-base Voltage Stability Monitoring method has been validated on the Central East Interface. Since PMUs are not currently available at the five substations of the receiving end of the interface, we perform time-domain simulations to obtain the voltage and current waveforms at those substations and use them as pseudo PMU data. The results show that the Measurement-base Voltage Stability Monitoring method:

- can detect voltage instability problems in real-time
- can help operators monitor system voltage stability condition by providing the power transfer limits in terms of real or reactive power.

This monitoring function does not require modeling transmission system components and does not rely on the SCADA/EMS. The margin information provides system operators not only the power transfer limit to a load center (or on the transmission corridor), in terms of active power, but also the reactive power support needed. This information can be used as decision support for the operator to take actions to improve voltage stability. The set of control actions include but not limited to:

- increasing reactive power output from generators
- switching on shunt capacitors
- increasing reactive power output from SVC
- configuration of transmission network
- load shedding

Future Work

Preliminary analytical studies have demonstrated the advantages and benefits of using this technology to monitor voltage instability on the Central East interface. With all this knowledge in hand, we are collaborating with NYISO and Transmission Owners to move this invention into the pilot studies and then into full-scale demonstration.

New York State now has 10 PMUs installed at NYPA, ConEd, and LIPA footprints. All of the PMU data is being sent to TVA's Super PDC through a secure fiber network. NYISO are focusing on expanding the number of PMUs, developing a Phasor Data Collector (PDC) and deploy real-time wide area monitoring capabilities on grid dynamics to operators and reliability coordinators. It is necessary to develop an interface between the Measurement Based Voltage Stability Monitoring (MB-VSM) program and NYISO's PDC so that the MB-VSM program can use New York State's existing PMU data.

A number of tests need to be performed in order to verify the performance and examine the robustness of the MB-VSM algorithm. We need to validate the correctness of the computation results and check the computation time of the MB-VSM program using the historical PMU data, as well as assess the robustness of the MB-VSM program against the potential loss of a PMU, and some communication channels. The following existing PMUs could be used to examine the performance of MB-VSM:

UPNY-ConEd interface

- FARRAGUT -345KV (existing PMU)
- SPRBROOK – 345KV (existing PMU)

LIPA Import interface

- E.G.C.-1 – 345KV (existing PMU)

The full-scale demonstration phase requires PMUs to be installed at designated locations to monitor voltage stability on the Central-East and UPNY-ConEd (or Millwood South) interfaces. Table 7-1 shows the proposed implementation architecture of the MB-VSM on the New York System.

Table 7-1: Required PMU locations to implement MB-VSM

Bus Name	KV	TO	MBVSM-TE/CE	MBVSM-UC/MS
BUCH N	345	ConEd		
DUNWODIE	345	ConEd		X
FARRAGUT	345	ConEd	X	X
GOTHLS N	345	ConEd	X	X
RAMAPO	345	ConEd	X	
SPRBROOK	345	ConEd		X
E.G.C.-1	345	LIPA	X	X
NWBRG	345	LIPA	X	X
COOPC345	345	NYSEG	X	
N.SCOT77	345	Ngrid	X	
ROTRDM.2	230	Ngrid	X	
GILB 345	345	NYPA	X	
N.SCOT99	345	Ngrid	X	

These PMUs will measure the voltage magnitude and angle of the key substation buses, as well as the current of the key transmission lines, which are required by the MS-VSM program. Communication equipment and the necessary communication network connection need to be established in order to transfer the synchrophasor data from the PMUs to the NYISO's PDC. MB-VSM program will be installed at the application server connecting with NYISO's PDC as shown in Figure 7-1. The MB-VSM program will use the synchrophasor data provided by NYISO's PDC to calculate the voltage stability margin of the Central-East and UPNY-ConEd (or Millwood South) interfaces on a continuous basis. The voltage stability margin will be displayed on a designated computer screen at NYISO's control center for system operators to monitor the voltage stability condition of these two interfaces. Once the voltage stability margin falls below a user-specified threshold, an alarm message will be generated to inform system operators.

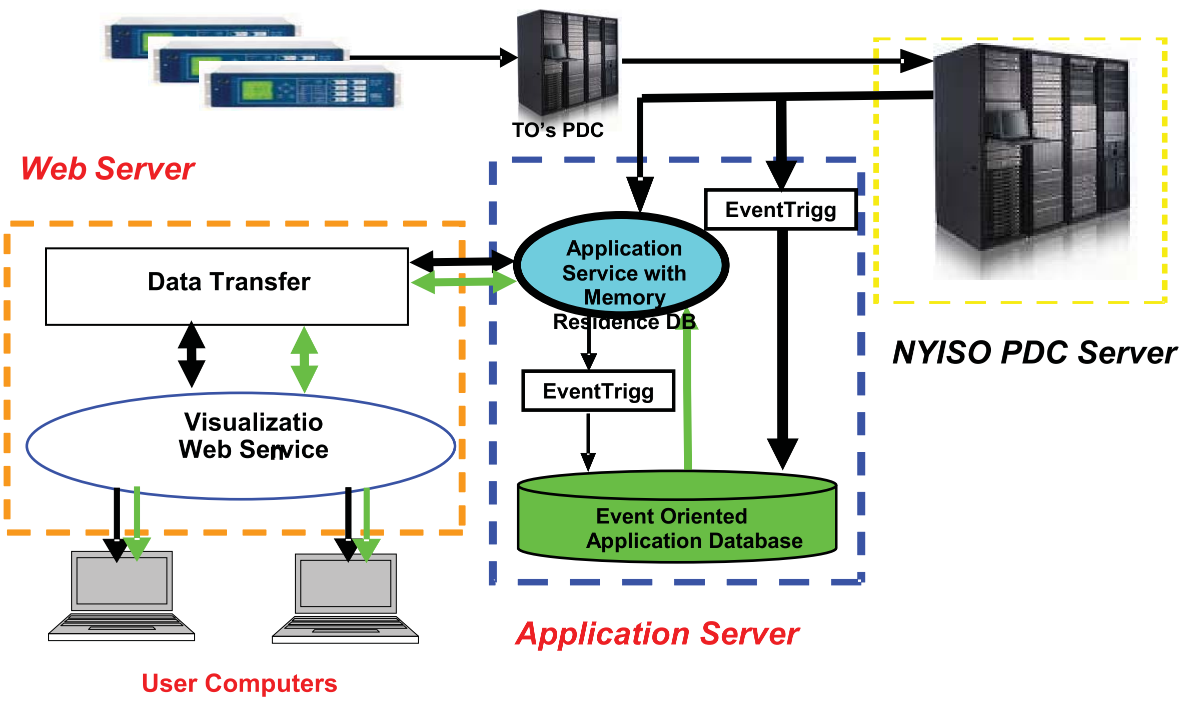


Figure 7-1 Proposed application architecture

Section 8: References

1. EPRI Technical Update: Voltage Instability Load Shedding. EPRI, Palo Alto, CA: 2006. 1012491.
2. “Method for Voltage Instability Load Shedding Using Local Measurement”, U.S. Patent Application Serial No. 11/539758, filed in October 2006;
URL: http://www.freepatentsonline.com/y2008/0086239.html
3. EPRI Technical Update: Validation of Voltage Instability Load Shedding Method Using TVA 2003 Voltage Collapse Event, EPRI, Palo Alto, CA: 2007. 1013955.
4. “Measurement-Based Voltage Stability Monitoring for Load Center”, U.S. Patent Application Serial No. 12/131,997, filed in May 2008.
5. EPRI Technical Report: Measurement Based Wide-Area Voltage Stability Monitoring, EPRI, Palo Alto, CA: 2009. 1017798/.
6. URL: http://tdworld.com/test_monitor_control/top_story/entergy-epri-monitoring-method-0109/index.html
7. NYISO, 2009 Comprehensive Reliability Plan Comprehensive System Planning Process; FINAL REPORT; May 19, 2009;
URL: http://www.nyiso.com/public/services/planning/reliability_assessments.jsp
8. NYISO, 2009 Load & Capacity Data “Gold Book”; April 2009;
URL: http://www.nyiso.com/public/services/planning/planning_data_reference_documents.jsp
9. URL: http://www.ferc.gov/market-oversight/mkt-electric/new-york.asp#geo
10. NYISO Operating Study Summer 2009; May 14, 2009;
URL: http://www.nyiso.com/public/
11. PSS/E version 31 user manual.
12. NERC White Paper on Delayed Voltage Recovery – Cause, Risk, and Mitigation.
URL: http://www.nerc.com/docs/pc/tis/White_Paper_on_Delayed_Voltage_Recovery_R16.pdf
13. EPRI Technical Report: Measurement-Based Load Modeling. EPRI, Palo Alto. CA: 2006. 1014402.
14. EPRI Software: Load Model Data Processing and Parameter Derivation (LMDPPD) Version 2.1. EPRI, Palo Alto. CA: 2009. 1020175.

Appendix

Section A: Central East and UPNY-ConEd Interface PV Analyses

The objective of this project is to demonstrate the new approach developed by EPRI called the Voltage Instability Load Shedding to prevent voltage collapse with an automatic safety net or system protection scheme that will automatically shed the right amount of load to arrest an impending voltage collapse by using high-sampling rate digital measurement devices such as Digital Fault Recorder (DFR), PMU or intelligent electronic devices (IED) installed at the substation level. It also demonstrates its ability to provide real-time voltage stability margins that are computed from the real-time data of the DFR, PMU or IED.

In order to do so, the project team needs to determine critical substations and/or load centers for voltage instability. The team will select the critical substations related with voltage stability problems. Substations that are connected to radial loads would also be ideal for this research. The team will additionally consider whether those substations have the capability of measuring the phase voltages and currents continuously. Past experiences of New York transmission planners about the potential interfaces of voltage instability will be used to the maximum degree so as to select the most promising substations where this Task will focus on for further research.

Recommendations

Results and observations of recent NYISO voltage stability analysis indicated that the transfer capabilities on the Central East and UPNY-ConEd interfaces were constrained by not only internal New York's system contingencies but also loss-of-source contingencies outside New York's system. These constraints need to be coordinated and evaluated on an interregional basis, which falls well into the objective of this project – Wide Area Power System Analysis and Visualization using PMU. Therefore, the team selected the Central East and UPNY-ConEd interfaces as the primary interfaces to select most promising substation where this task will focus on for further investigation.

Next session (session 3) of this report includes selected results of the stability analysis, copies of PV curves, interface definitions and base case assumptions made in developing the various transfer cases.

For the Central East interface, the following critical buses were selected for voltage stability monitoring and analysis purpose:

- New Scotland 345 KV
- LEEDS 345 KV
- EDIC 345 KV
- ROTRDM 230 KV
- INGHAM 115 KV
- GRAND IS 115KV

For the UPNY-ConEd interface, the following critical buses were selected for voltage stability monitoring and analysis purpose:

- FARRGUT 345KV
- GOETHALS 230KV

- SPRAINBROOK 345 KV
- DUNWOODIE 345
- MILLWOOD 345
- WEST 49th St 345 KV
- PLEASANT VALLEY 345 KV
- EAST FISHKILL 345 KV
- RAMPO 345 KV
- NEWBRIDGE 345KV
- JAMAICA 138 KV
- CORONA 138 KV
- GREENWOOD 138 KV
- EAST 179th St 138 KV
- ASTORIA EAST 138 KV
- ASTORIA WEST 138 KV
- SHOREHAM 192/138KV
- NRTHPT P 138KV

Dynamic analysis will be commonly employed in the further study of power system stability to reveal system trajectory after a disturbance. In contrast to static analysis in which equilibrium points of a P-V curve are not time-dependent, dynamic analysis results will reveal the transient and the dynamic voltage recovery performance of a power system under study.

Study Methodology and Results

The team tested various contingencies on 2012 Summer Case for NY Central East transfer and UPNY ConEd transfer. Edic and New Scotland 345 KV bus voltages were monitored for Central East transfer, Pleasant Valley and Sprain Brook 345 kV bus voltages were monitored for UPNY-ConEd transfer.

There are three shunt compensators in the NYISO system; these are located at the Marcy (79799), Fraser (75402), and Leeds 345kV (78701) stations. The Leeds and Fraser installations are Static VAr Compensators (SVC). The Marcy CSC is modeled in the shunt (STATCOM) mode. These SVCs/FACTS devices are set to zero reactive output pre-contingency and have their full dynamic range of the reactive compensation available post-contingency.

Figure A-1 shows the Central-East and UPNY-ConEd interfaces on the equivalent NYHV system. Table A-1 and Table A-2 provide these two interfaces' definitions. The transfer through the Central-East interface is approximately 2320 MW for the base case condition. The transfer through the UPNY-ConEd interfaces is approximately 4350 MW for base case condition.

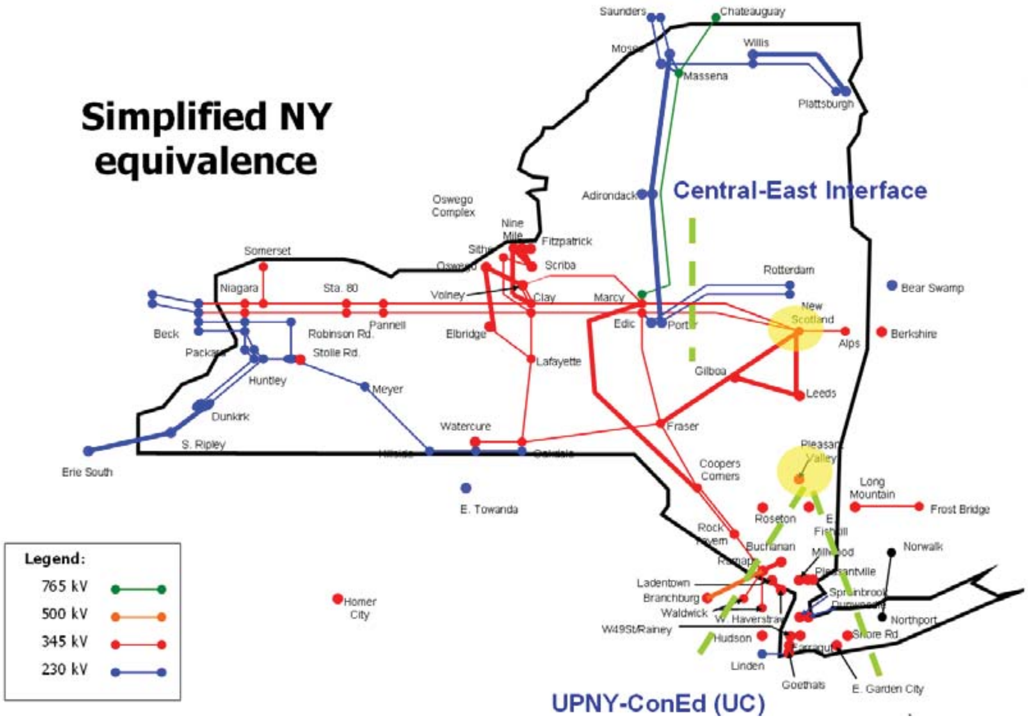


Figure A-1 Central East and UPNY-ConEd Interfaces

Table A-1: Central East Interface Definition

From Bus	To Bus	CKT	Voltage (KV)
E.SPR115 115	INGHAM-E 115	1	115
JORDANVILLE 230	ROTRDM.2 230	1	230
PORTER 2 230	ROTRDM.2 230	2	230
INGMS-CD 115	INGHAM-E 115	1	115
MARCY T1 345	N.SCOT99 345	1	345
PLAT T#3 115	GRAND IS 115	1	115
EDIC 345	N.SCOT77 345	1	345

Table A-2: UPNY-ConEd Interface Definition

From Bus	To Bus	CKT	Voltage (KV)
ROSETON 345	FISHKILL 345	1	345
FISHKILL 115	SYLVN115 115	1	115
E FISH I 115	FISHKILL 345	1	115
LADENTWN 345	BUCH S 345	1	345
PLTVLLEY 345	FISHKILL 345	1	345
PLTVLLEY 345	FISHKILL 345	2	345
PLTVLLEY 345	MILLWOOD 345	1	345
PLTVLLEY 345	WOOD B 345	1	345
RAMAPO 345	BUCH N 345	1	345

Central East Voltage Analysis

Source/Sink Definition[1]

- Source Definition "TE-G Shift"
  - *DUNKGEN313.8*
  - *HNTLY68G13.8*
  - *9M PT 1G23.0*
  - *MOS19-2013.8*
  - *NANTICG622.0*
  - *LENNOX*

- Sink Definition "Opposing"
  - *N.PORT*
  - *E RIVER (74301)*
  - *E RIVER (74302)*
  - *RAV 1*
  - *AST 5*
  - *AST 4*
  - *AK 2*

[1] Transfer Scenarios: Increase Gen in Source and Decrease Gen in Sink

Contingency Evaluation

- Transmission Contingency
  - Tower #40&41-Edic-Fraser & Marcy-Cooper Corners 345 kV
  - Tower #41&43-Marcy-Coopers Corners & Fraser-Coopers Corners
  - New Scotland #77 345 kV Bus Fault
  - New Scotland #99 345 kV Bus Fault

- Generation Contingency2
  - Indian PT #2 @FULL LOAD (980 MW)
  - Millstone #3 @FULL LOAD (1150 MW)
  - Seabrook #1 @FULL LOAD (1150 MW)
  - Sandy Pond HVDC 1,800 MW
  - Sandy Pond HVDC 1,600 MW

Central East Results

For the conditions and contingencies tested, the Central East Pre-Contingency Maximum Transfer appears to be approximately 2,600 MW. TWR 41&43 contingency (Tower contingency -Marcy-Coopers Corners #41 and Fraser-Coopers Corners #43 345 kV lines) is the most limiting voltage contingency. The Sandy Pond HDVC contingency at 1,600 MW were less severe than the New York loss-of-source and transmission contingencies.

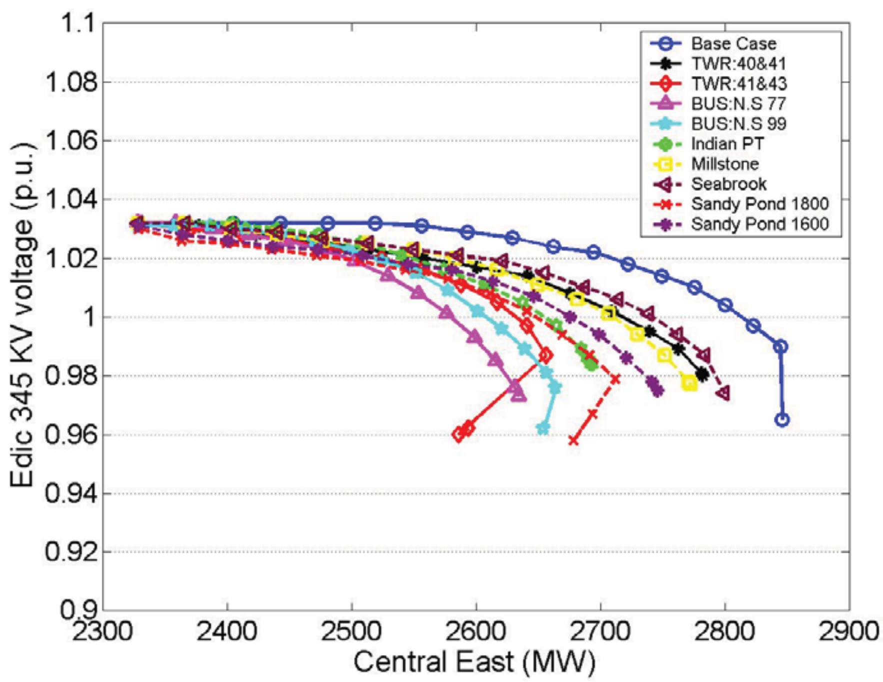


Figure A-2 Edic Voltage Performance vs. Central East Pre-Contingency Power Flow

[2] Generation Contingency (ATBA2007.inl): The post-contingency power flow solution for the generation contingencies are solved using the PSS/e inertial solution activity (INLF); this is a Newton-Raphson solution where all generation in the network is re-dispatched relative to its capability to compensate for the loss of source.

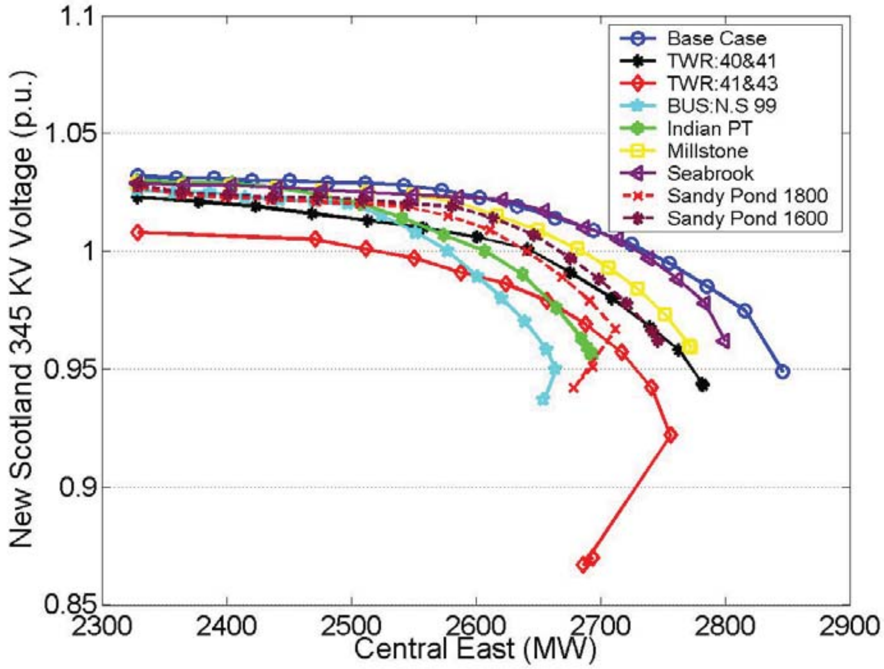


Figure A-3 New Scotland Voltage Performance vs. Central East Pre-Contingency Power Flow

UPNY-ConEd Voltage Analysis

Source/Sink Definition[3]

- Source Definition "UC-G Shift"
  - DUNKGEN313.8
  - HNTLY68G13.8
  - 9M PT 1G23.0
  - MOS19-2013.8
  - NANTICG622.0
  - LAMBTNG424.0

- Sink Definition "Opposing"
  - N.PORT
  - E RIVER (74301)
  - E RIVER (74302)
  - RAV 1
  - AST 5
  - AST 4
  - AK 2

Contingency Evaluation

- Transmission Contingency

---

[3] Transfer Scenarios: Increase Gen in Source and Decrease Gen in Sink

- L/O Y86/Y87 CKT.
- SBK BUCHANAN 345
- L/O Y88/Y94 CKT. (BUCHANAN RIVER CROSSING)
- TWR W89/W90
- TWR 30/31
- SBK ROCK TAV 345 37751 (77 & CCRT-42)
- TWR 34/42 @ COOPERS CORNERS
- TWR W97/W98

UPNY-ConEd Results

For the conditions and contingencies tested, the UPNY-ConEd Pre-Contingency Maximum Transfer appears to be approximately 4,520 MW. Stuck Break contingency at BUCHANAN 345KV station is the most limiting voltage contingency.

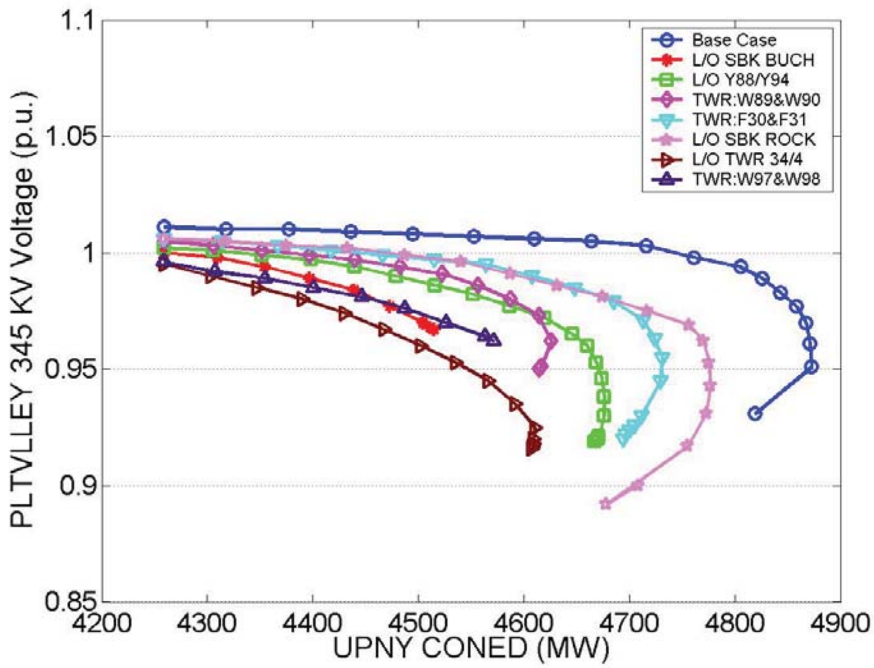


Figure A-4 PLTVLLEY Voltage Performance vs. UPNY CONED Pre-Contingency Power Flow

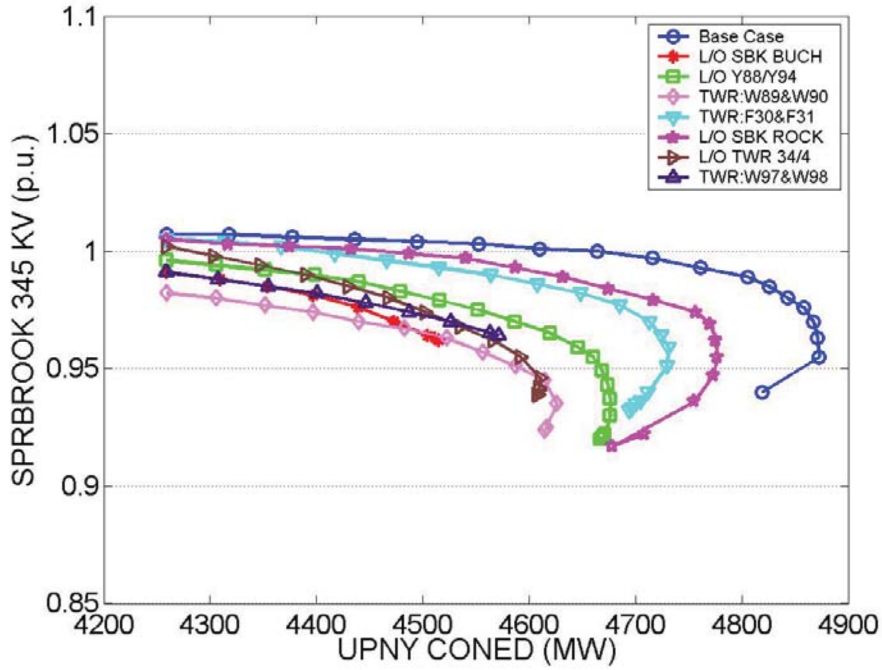


Figure A-5 SPRBROOK Voltage Performance vs. UPNY CONED Pre-Contingency Power Flow

Appendix D: Public Workshop Agenda

New York State Energy Research and Development Authority
17 Columbia Circle
Albany, NY 12203-6399
1-866-NYSERDA • (518) 862-1090 • www.nyserda.org

ELECTRIC POWER RESEARCH INSTITUTE

****

ANNOUNCEMENT

Project Workshop: Real-Time Applications of Phasor Measurement Units (PMU) and Fast Fault Screening Tool for Real-Time Transient Stability Assessment

Sponsored by: New York State Energy Research and Development Authority
New York Independent System Operator
Electric Power Research Institute

When: Tuesday, May 25th 2010
Where: New York ISO
10 Krey Boulevard
Rensselaer, NY 12144

****

The goal of this Workshop is to present the results of two research projects under NYSERDA, performed by EPRI on the related subject of synchrophasor applications and real-time transient stability assessment. The research involves the New York Independent System Operator and New York Transmission Owners and uses the New York electric power grid as the test system.

The first project is called Real-Time Applications of Phasor Measurement Units (PMUs) and deals with Wide-Area Visualization, Reactive Power Monitoring and Voltage Stability Protection. The second project is called Fast Fault Screening tool which quickly scans thousands of potential transmission fault locations and identifies the most severe locations for transient stability studies.

Attendance from electric utility operators and planners, researchers, software developers and vendors, regulators, policy makers, consumers, and non-governmental organizations are welcome. The purpose of reaching out to this broad audience is to inform the public, to promote research in this technical area, and to provide useful technical information for potential commercialization of methodologies developed in these two research projects.

Reference Links:

NYSERDA Transmission and Delivery Program:
http://www.nyserda.org/Programs/IABR/IndustryProgramAreas.asp#td

Agenda:

Time	Agenda Item	Speaker
9:00 am	Welcome and Introduction by NYSERDA	Mike Razanousky, NYSERDA
9:15	Importance of Research Areas to New York from the NYISO's Perspective	Richard Dewey, NYISO
10:00	Overview of Research Objectives – Project 10470 Real-Time Applications of PMU	Liang Min, EPRI
10:15	Break	
10:30	Real-Time Applications of PMU Topic 1: Wide Area Visualization and Location of Disturbance	Guorui Zhang, EPRI
11:15	Real-Time Applications of PMU Topic 2: Critical Voltage Control Areas and Required Reactive Power Reserves	Liang Min, EPRI
12:00 pm	Lunch	
1:00 pm	Real-Time Applications of PMU Topic 3: Voltage Stability Protection	Liang Min, EPRI
1:45	Discussion, Comments, Questions and Answers	
2:15	Break	
2:30	Overview of Research Objectives – Project 10471 Fast Fault Screening	Liang Min, EPRI
2:45	Fast Fault Screening	Marianna Vaiman, V&R
3:30	Discussion, Comments, Questions and Answers	
4:00	Summary & Conclusions	Mike Razanousky, NYSERDA
4:30	Adjourn	

For information on other
NYSERDA reports, contact:

New York State Energy Research
and Development Authority
17 Columbia Circle
Albany, New York 12203-6399

toll free: 1 (866) NYSERDA
local: (518) 862-1090
fax: (518) 862-1091

info@nyserda.org
www.nyserda.org

Real-Time Applications of Phasor Measurement Units (PMU) for Visualization, Reactive Power Monitoring and Voltage Stability Protection

Final Report 10-33

Energy. Innovation. Solutions.