

# Evaluate Real-Time System Reliability Using Boundary-Based Concept for EKPC System

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**Abstract**— This paper addresses a comprehensive approach to evaluate reliability in a large transmission system for on-line and real-time environments. The paper also addresses the growing need for broader coordination between planning and operations. The paper describes how the boundary-based AC approach was utilized to evaluate the reliability of the EKPC network. The approach described in this paper offers a unique capability to automatically identify the boundary of the secure operating region for each contingency and rank contingencies in on-line and off-line environments. The study also shows how to optimize a transmission system using existing resources without building new transmission. The study was performed using the EKPC loadflow data to validate the proof of concept. It took under 20 minutes to perform AC contingency analysis on over 3,700 N-1 contingencies. The approach described in this paper will allow the operators to perform exhaustive analysis and determine the boundary of stability.

**Index Terms**— Transmission reliability, boundary of stability, secure operating region, AC contingency analysis, optimal mitigation measures; contingency ranking.

## I. INTRODUCTION

TRANSMISSION owners and operators must operate their networks as efficiently and as optimally as possible to assure the maximum utilization of the transmission network and assets.

Analyses of every major blackout since implementation of the Open Access Order FERC 888 and 889 have concluded that system operators probably could have mitigated the extent and damage of blackouts if they had had access to near real-time (or on-line) software tools that could have identified the impending crisis and provided operators with the core data needed to make timely, informed decisions [1].

Because of the ever increasing cost for new transmission and the resistance to siting new transmission, the need for

optimizing the existing system resources is increasing.

It is of utmost importance to ensure that the transmission system is being operated in a safe and reliable manner when optimization pushes system limits. The approach described in this paper has been demonstrated by National Rural Electric Cooperative Association (NRECA) Cooperative Research Network (CRN) for the East Kentucky Power Cooperative (EKPC) transmission system.

The NERC 2007 Long-Term Reliability Assessment report [2] states that “Advanced tools that focus on the boundary of stability, rather than single point analysis are needed to provide better planning and operating tools”.

The paper addresses the testing and implementation of a fast process to determine and visually present the boundaries of the secure system operating region, monitor the state of EKPC transmission system on-line and off-line using the “boundary” concept, calculate how close the system is to the maximum allowable state of power transfer, and suggest ways to mitigate any violations that constrain the transmission system from reaching the maximum allowable state of operation. Results of the EKPC study indicate that extra capacity in the EKPC system can be realized without resorting to the addition of new transmission.

The study described in this paper addressed the following two recommendations from the NERC report [2]:

1. A need for broader coordination between planning and operations
2. Focus on the boundary of stability, rather than single point analysis

The programs “Physical and Operational Margins” (POM), “Optimal Mitigation Measures” (OPM) and “Boundary of Operating Region” (BOR) of POM Suite of Applications were used as the basis for all computations in this project [3].

POM is an extremely fast AC loadflow and contingency analysis program that solves a 45,000-bus case in approximately 0.2 s. [4]. POM contingency analysis and transfer simulation results are always within four system constraints, which may be simultaneously monitored by the user. Those four constraints are: (1) Voltage stability, (2) Thermal overload of lines and transformers, (3) flowgate limits, and (4) Voltage violation (voltage range and/or pre-contingency to post-contingency voltage drop).

POM capabilities include:

- Contingency analysis (N-1, N-1-1, N-2, N-3 and higher) for large power system models;

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This work was supported by the NRECA CRN’s Transmission Reliability and Security Membership Advisory Group award.

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- Cascading outages assessment;
- Simulate multiple power transfers while monitoring voltage, thermal, flowgate, voltage stability constraints during contingency analysis;
- Determine maximum loadability in the loads of interest while monitoring voltage, thermal, flowgate and voltage stability constraints during contingency analysis.

Optimal Mitigation Measures (OPM) is a fast and powerful program that provides remedial actions or transmission expansions to maintain and increase power system reliability. Fully integrated into the POM and BOR applications, OPM relieves thermal, voltage, and voltage stability violations identified by POM and increases loadability and transfer capability [5]. OPM also determines the causes of voltage stability violations and recommends operating actions to increase voltage stability margins. In addition, OPM identifies critical/sensitive generators that are essential to avoid voltage collapse.

Boundary of Operating Region (BOR) is a powerful AC tool that identifies and illustrates the region within which the system operation is secure [6-8]. BOR finds AC limits while simultaneously changing several model parameters (for example, simultaneous transfer scenarios) based on voltage stability, voltage, and thermal constraints. The tool has the ability to automatically generate nomograms for planning and real-time environments.

## II. THE PROJECT BACKGROUND, OBJECTIVES AND SCOPE

In 2005, EKPC began to encounter thermal violations on a number of facilities. Upon investigation, it was determined that massive North-to-South power transfers between the mid-Atlantic region and the Southeast were a major contributing factor to EKPC's overloading problems. With that, EKPC wanted to find a new modeling tool that could assist in resolving the problem and enhance the reliability of the EKPC network in both on-line and real-time environments.

The objectives of the NRECA CRN project "Evaluation of Real-Time System Reliability (Optimization) Software" were:

- Implement NERC's recommendation to utilize "tools that work towards identification of the boundary of stability [2];
- Alleviate congestion in the EKPC network based on the concept of the boundary of secure operating region;
- Identify the benefits that real-time monitoring of the transmission system can provide to transmission owners, particularly those facing the new reliability standards of FERC 890 and NERC/ERO.

The scope of the project is:

- Comprehensive contingency analysis of the EKPC system. Optimal mitigation measures are automatically determined for each contingency during the comprehensive AC contingency analysis. Identify bottlenecks in the power system and provide ways to rapidly alleviate them.

- Available transfer capability computations. The transfer capability limits at the interfaces with foreign utilities are determined while the constraints are monitored and the most-limiting facilities are identified.
- Determining the secure operating region. The boundary of the secure operating region and limiting constraints are determined and visually displayed while simultaneous transfers are simulated. Optimal mitigation measures that increase the size of the secure operating region are then determined.

## III. ALLEVIATING TRANSMISSION SYSTEM BOTTLENECKS DURING MASSIVE CONTINGENCY ANALYSIS

### A. Performing Massive AC Contingency Analysis

To start, a massive AC contingency analysis was performed on the EKPC system model, which included all or part of six control areas: LGEE/KU, EKPC, AEP, CIN, DPL, and TVA. A total of 3,736 N-1 contingencies were applied during this simulation on the power system network model consisting of 8,777 buses and 26,215 branches. Voltage and thermal constraints were monitored and maintained on all EKPC buses and on all buses of one foreign utility within the model. A low voltage limit of 0.925 p.u. was set, monitored, and enforced on all EKPC buses, while 0.95 p.u. was used for the neighbor utility.

Out of 3,736 N-1 contingencies 141 contingencies (less than 4%) were identified as critical. Critical contingencies are contingencies that cause violation of the monitored constraint(s).

Critical contingencies caused voltage constraint violations and thermal overloads on lines and transformers. There were no voltage stability violations.

Contingency analysis results showed that the system under consideration is mostly voltage constrained. However, the majority of voltage violations are not severe; i.e., post-contingency voltage levels are close to the voltage limit for that bus (see Fig. 1).

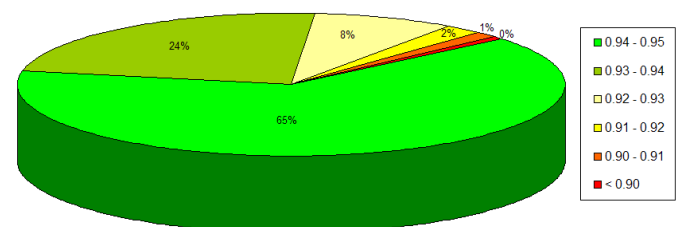


Fig. 1. Severity of Post-Contingency Voltage Violations: Voltage Limit = 0.95 p.u.

Less than 1% of post-contingency voltages drop below 0.9 p.u. (see Fig. 1) at buses where the low voltage limit of 0.95 p.u. was imposed.

Voltage constraint violations occur only 19 times at buses where the voltage limit is 0.925 p.u. The distribution of these violations by severity is shown in Fig. 2.

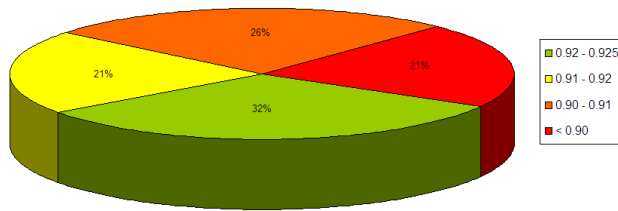


Fig. 2. Severity of Post-Contingency Voltage Violations: Voltage Limit = 0.925 p.u.

Only two contingencies cause voltage violations below 0.9 p.u.

There are several pockets where buses violate voltage criteria. The area that is shown in Fig. 3 is one example.

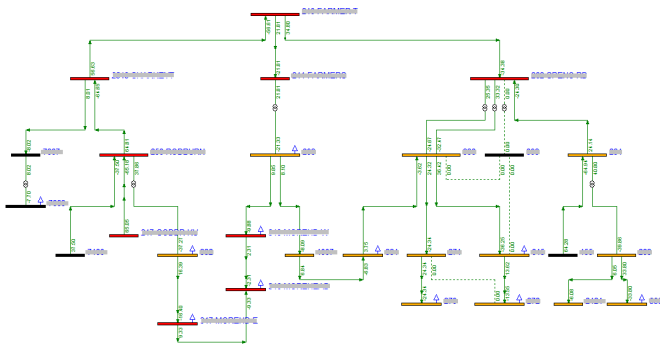


Fig. 3. System Bottlenecks - Voltage Constraint

As shown in Fig. 3, voltage constraint is a local problem.

Several thermal overloads were also identified. The results show that only three lines are overloaded more than one time as a result of contingency analysis. Transmission line bottlenecks have local spread.

### B. Determining Optimal Mitigation Measures to Alleviate Post-Contingency Violations

At the same time that bottlenecks in the transmission system were being identified, mitigation measures that alleviate the identified violations were determined.

Of the many mitigation measures modeled in OPM, MVAR re-dispatch was assigned the highest priority by EKPC. It was followed by transformer tap change and capacitor and reactor switching measures. These were followed by MW dispatch and switching lines. Load curtailment was assigned the lowest priority.

As a result, all post-contingency violations resulting from the 141 critical contingencies identified previously were alleviated, and mitigation measures for each contingency were determined. The MVAR re-dispatch measure, which changes scheduled voltage setpoints of generators and continuous shunts, was shown to be very effective for alleviating the vast majority of the violations (see Fig. 4).

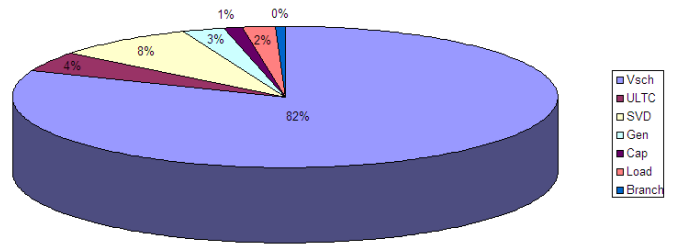


Fig. 4. Distribution of Mitigation Measures Used to Alleviate Post-Contingency Violations

This measure was recommended for the successful mitigation of 82% of the post-contingency violations. The study results showed that voltage setpoint should be changed at a limited number of buses, which were automatically identified in the course of the analysis.

Changing the voltage setpoint at ten buses, identified during the course of analysis, reduces the number of critical contingencies from 141 to 58. Thus, changing the voltage setpoint (MVAR re-dispatch measure) at these ten buses may be utilized as a preventive measure to meet N-1 reliability criteria.

Another run was performed where the size and placement of additional sources of reactive power (capacitors) as the only mitigation measure were recommended. Installing additional sources of reactive power at two buses where voltage violation occurs the most frequent number of times during N-1 contingency analysis was identified as the most effective measure. Installing an additional 9 MVAR at each of these two buses reduces the number of critical contingencies from 141 to 99.

### C. Computing Voltage Stability Margins

Upon determining effective mitigation measures to alleviate post-contingency voltage and thermal violations, the voltage stability margin for each of 3,736 N-1 contingencies was computed in order to assess the vulnerability of the power system network.

To determine voltage stability margins, the model's base case load in EKPC and the neighboring control area was steadily increased by 200 MW load increments. The maximum load increase (above the base case load) was found to be 2,400 MW without any contingencies applied (N-0 conditions). Two contingencies have a 1,400 MW margin, two contingencies have a 2,000 MW margin, one contingency has a 2,200 MW margin, and 5 contingencies have a 2,400 MW margin as shown in Fig. 5.

The remaining 3,726 contingencies do not cause voltage stability violations up to 2,400 MW. Thus, stability violations after these contingencies are caused by the maximum load level being reached in the two control areas (e.g., do not represent the effect of these contingencies).

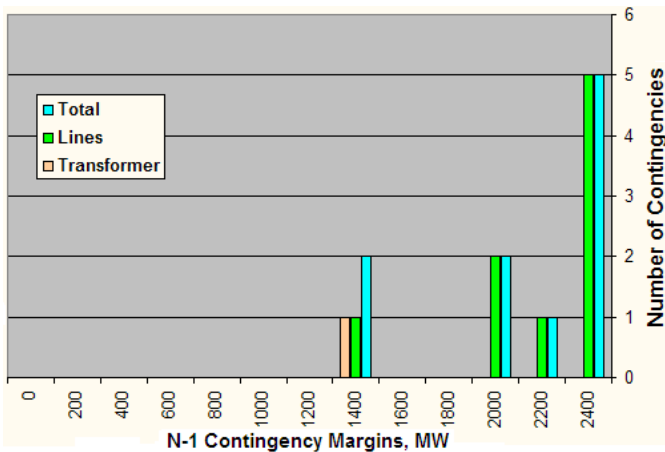


Fig. 5. Voltage Stability Margins for N-1 Contingencies

Voltage stability margin is a good indicator of network health – high margins indicate strong networks while low margins indicate weak systems.

Results from this study show that voltage stability margins for all N-1 contingencies are high; thus, the EKPC system is in good health.

#### IV. DETERMINING MAXIMUM TRANSFER CAPABILITY

##### A. Determining Maximum Transfer Capability for North-South Transfer

A power transfer on EKPC's north-south system was simulated from OHIO, AEP, DPL, MAAC and MECS to TVA and SERC as shown in Fig. 6.

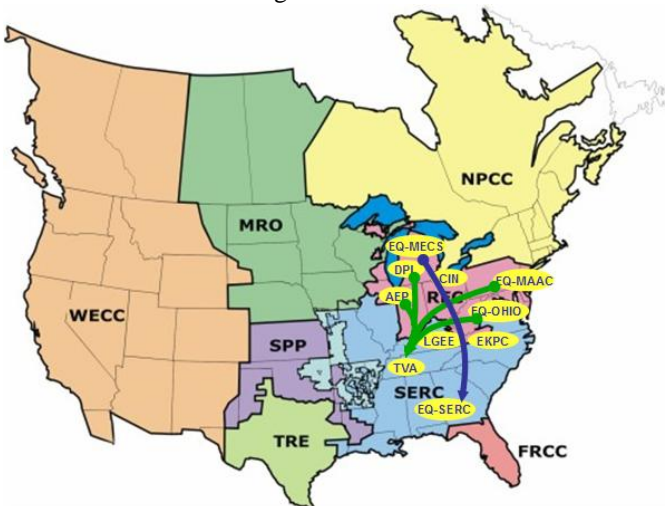


Fig. 6. The North-South Power Transfer

Fig. 7 graphically shows that the maximum north-south transfer capacity is 1,400 MW for base conditions (e.g., N-0 conditions). Fig. 7 shows that there is a sharp increase in post-contingency thermal loading (magenta curve). Fig. 7 also shows that a low voltage limit violation (green curve) at a 138 kV bus is the first limiting facility.

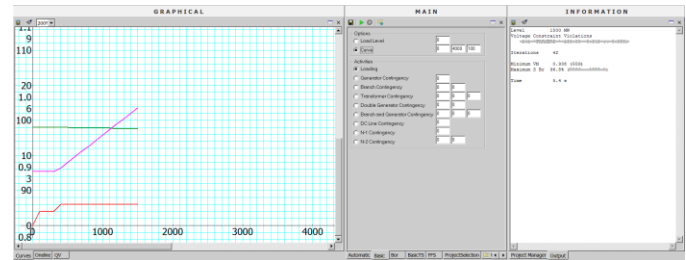


Fig. 7. Simulating the North-South Power Transfer

##### B. Increasing Maximum Transfer Capability for North-to-South Transfer Using Mitigation Measures

By applying mitigation measures, recommended by OPM, the maximum transfer capability was increased by 2,000 MW, from 1,400 MW to 3,400 MW—an increase of 2.5 times. Four mitigation measures were utilized, in the following order of priority:

- MVAR re-dispatch
- Transform tap change
- Capacitor and reactor switching
- Line switching

MVAR re-dispatch, without other mitigation measures, proved highly effective. Changing the voltage setpoint at only one bus, identified during the course of the study, increased the maximum north-south transfer by 500 MW, from 1,400 MW to 1,900 MW—a 36% increase, see Fig. 8.

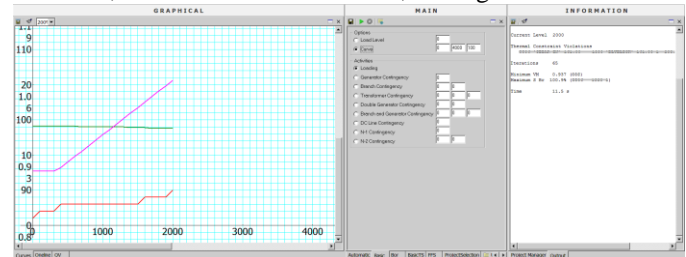


Fig. 8. Result of Adding MVAR Re-dispatch at One Bus to the North-South Transfer Scenario

At that point, thermal overload (magenta curve) of a 161 kV line becomes the first limiting facility as shown in Fig. 8.

##### C. Determining and Increasing Available Transfer Capability under All Contingency Conditions

Available transfer capability was determined for each of the 3,736 N-1 contingencies. The study showed that 3,356 of these contingencies do not affect the North-South transfer (their transfer capability exceeds 1,400 MW). The maximum transfer capability for 380 contingencies (~ 10% of all contingencies simulated) is 1,400 MW or lower.

Fig. 9 presents a chart of the results for the first 100 contingencies in which the columns correspond to contingencies and the rows are power transfer levels, with the lowest level at the top and highest at the bottom. The figure is color-coded as follows:

- White indicates that there is no violation.
- Green indicates a voltage constraint violation.
- Magenta indicates a thermal constraint violation.

The first column, labeled BC, represents conditions before any contingency.

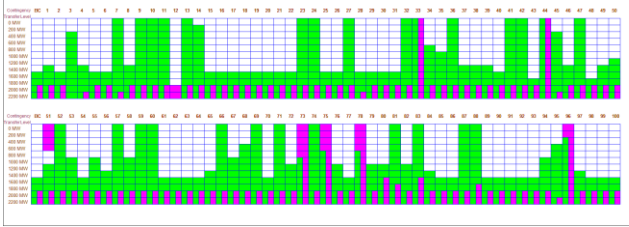


Fig. 9. Available Transfer Capability and Limiting Constraints for the First 100 Contingencies

MVAr re-dispatch measure was introduced into the simulation to determine how much it would increase the available transfer capability under contingency conditions. The available transfer capability was significantly increased, as Fig. 10 shows. Fig. 10, like Fig. 9, shows the first 100 contingencies of the 3,736 contingencies, but with the MVAr re-dispatch measure being employed. The increase in the white (no-violation) areas is notable.

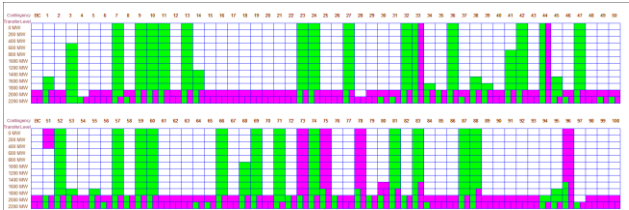


Fig. 10. Available Transfer Capability and Limiting Constraints for the First 100 Contingencies: MVAr Re-dispatch Measure at One Bus Utilized

## V. UTILIZING THE BOUNDARY-BASED SOLUTION FOR THE EKPC SYSTEM

### A. The Concept of the Boundary of the Secure Operating Region

The analysis described in this Section addresses the need to implement the concept of the boundary of secure system operation rather than single point analysis.

The secure operating region is the region, on the plane of studied parameters, within which operating the system does not violate any of the monitored and enforced constraints.

The boundary is given as a multi-colored graph. Each color on a boundary corresponds to a violation of one of the following constraints and limits: thermal overloads; voltage range violations; pre- to post-contingency voltage drop violations; flowgate violations; voltage stability violations.

The boundary of the operating region may be shown as a projection onto different planes, such as:

- Power injections
- Load and generation
- Interface and/or tie-line flows

When two transfers are simultaneously simulated, graphical results are displayed in 2-dimensional form. When three transfers are simultaneously simulated, graphical results are displayed in 2- and 3-dimensional forms.

The effect of contingencies on the size and the shape of the operating region and on the limiting constraints was identified.

The “boundary approach” also allows contingencies to be ranked based on the size of the operating region.

In this study, the region was constructed on the plane of two simultaneous power transfers. The boundary of the secure operating region is a combination of power transfers for which a violation of at least one of the monitored constraints occurs. Operating within the boundary is secure; i.e., each point within the boundary corresponds to an operating condition (some combination of the transfers) at which no monitored and enforced constraints are being violated.

### B. Determining the Boundary of the Secure Operating Region during North-South Transfer Simulation

The North-South power transfer was then represented as two independent transfers, indicated by blue and green arrows in Fig. 6. The secure operating region was determined for two simultaneous power transfers:

- Transfer 1: From OHIO, AEP, DPL, & MAAC to TVA
- Transfer 2: From MECS to SERC

Fig. 11 shows the boundary of the secure operating region for Transfer 1 and Transfer 2 for the base case conditions (e.g., N-0 conditions). Transfer 1 (in terms of power injections) is shown on the x-axis. Transfer 2 (in terms of power injections) is shown on the y-axis. The area below the boundary represents the secure operating region, e.g., combinations of Transfer 1/Transfer 2 for which there are no violations of thermal, voltage, and voltage stability constraints. The boundary corresponds to such combinations of Transfer 1/Transfer 2 for which violation of the monitored and enforced constraints occurs. The limiting condition for these two simultaneous transfers is voltage constraint (green color).

The original North-South transfer is represented by a straight line on the plane (Transfer 1, Transfer 2). The line, starting at point (0, 0) has a slope derived from the ratio of the participating transfers, Transfer 1 and Transfer 2. This line, shown in blue in Fig. 11 intersects the boundary at point  $P_0$  with coordinates  $P_1 = 1,085$  MW and  $P_2 = 365$  MW. Thus, the maximum North-South transfer of 1,450 MW occurs at  $P_0$ .

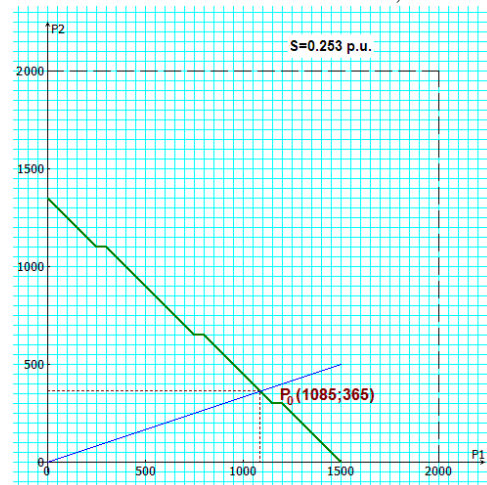


Fig. 11. The Boundary of Secure Operating Region for Two Simultaneous Transfers: Transfer 1 (x-axis) and Transfer 2 (y-axis)

The size of the secure operating region is 0.253 p.u.

### C. Increasing the Size of the Secure Operating Region Using MVAR Re-dispatch Measure

The MVAR re-dispatch measure identified in Section IV.B was utilized to increase the size of the secure operating region.

Fig. 12 shows the result of incorporating MVAR re-dispatch during simultaneous transfer simulation. The area below the curve represents the new secure operating region; the green portion of the boundary indicates where the secure area is voltage-constrained and the magenta portion indicates where it is thermally constrained.

The maximum north-south transfer,  $P_0$ , now occurs at 1,460 MW on transfer 1 and 480 MW on transfer 2, for a total of 1,940 MW. This is a 34% increase over the base case (without MVAR re-dispatch).

The affect of applying the MVAR re-dispatch measure at the bus identified in Section IV.B includes:

- Increasing the maximum transfer capability of Transfer 1 from 1,500 MW to 1,850 MW;
- Increasing the maximum transfer capability of Transfer 2 from 1,350 MW to 1,950 MW;
- Increasing the size of the secure operating region from  $S = 0.253$  p.u. to  $S = 0.497$  p.u.; almost two times.

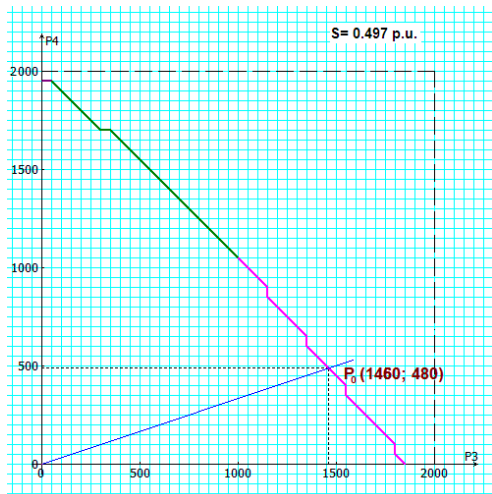


Fig. 12. BOR for Two Simultaneous Transfers: Transfer 1 (x-axis) and Transfer 2 (y-axis). MVAR Re-dispatch Measure Utilized

### D. Ranking Contingencies Based on the Size of the Secure Operating Region

This Section summarizes contingency analysis results for two simultaneous power transfers.

The contingency ranking is based on the size of the area of the operating region. The area of the operating region is computed for each contingency and the severity of the contingencies is based on the size of the operating region area. A smaller sized operating region corresponds to a more severe contingency.

The analysis applied the same 3,736 N-1 contingencies. Boundaries of the secure operating region for the first 41 contingencies are shown in Fig. 13.

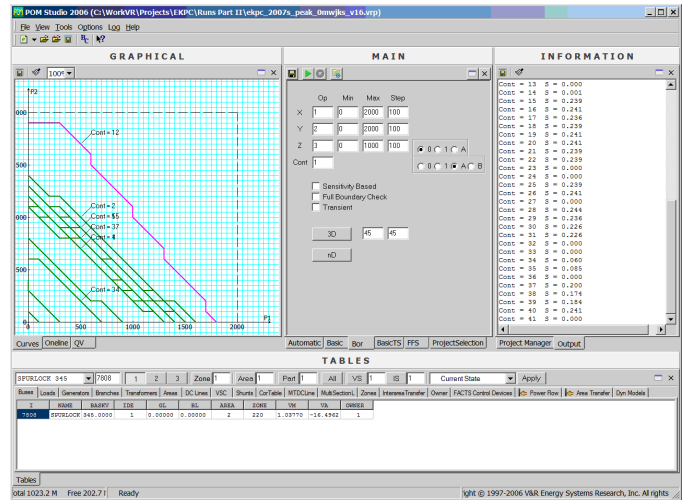


Fig. 13. Contingency Analysis While Simulating Two Simultaneous Transfers

Fig. 14 shows the distribution of the secure operating regions by size for all 3,736 contingencies plotted according to the contingency number.

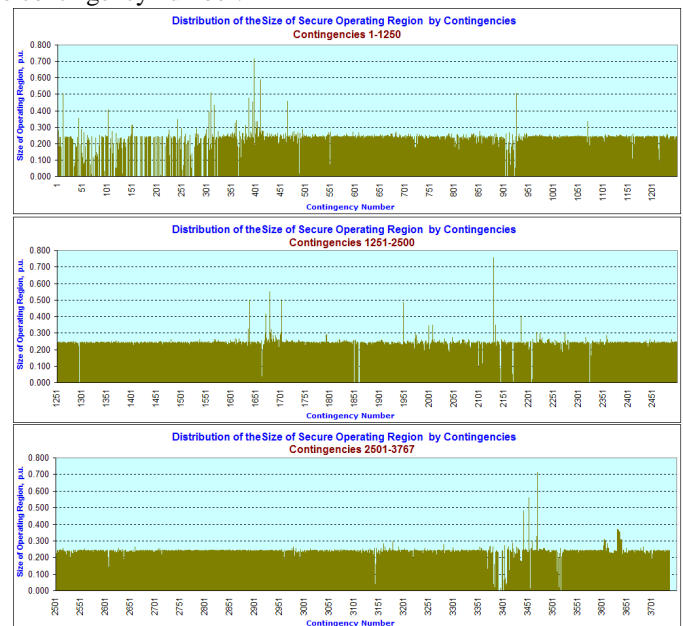


Fig. 14. Distribution of the Size of the Secure Operating Region for 3,736 Contingencies

Most contingencies did not reduce the size of the secure operating region (shown in Fig. 11) below that of the base case (0.253 p.u.). These contingencies do not have an affect on the transfer scenario.

Some contingencies, however, do have smaller secure operating areas than the base case as indicated by the sharp valleys in Fig. 14. These are the contingencies that have a limiting affect on the transfer scenario.

A small number of contingencies have larger safe operating areas than the base case. These are the occasional sharp peaks in Fig. 14 and are the contingencies that can be exploited as a mitigation measure for the transfer scenario under investigation (e.g., by opening these branches).

Overall, there are 140 contingencies with a secure operating area of zero. There is one contingency that has a secure

operating region of complex shape that does not include point (0, 0) - base case conditions. These are critical contingencies, which were previously identified in Section III.A.

Mitigation measures were identified in order to increase the size of the secure operating region. For example, contingency 14 has the smallest non-zero secure operating region with size 0.001 p.u. Utilizing MVar re-dispatch increases the size of the secure operating region for this contingency to 0.245 p.u - close to the base case area. Utilizing other mitigation measures (transform tap change; capacitor and reactor switching, and line switching) increases the secure operating region to 0.980 p.u - almost 4 times larger than the base case region. Fig. 15 illustrates the effect of mitigation measures on the secure operating region for contingency 14.

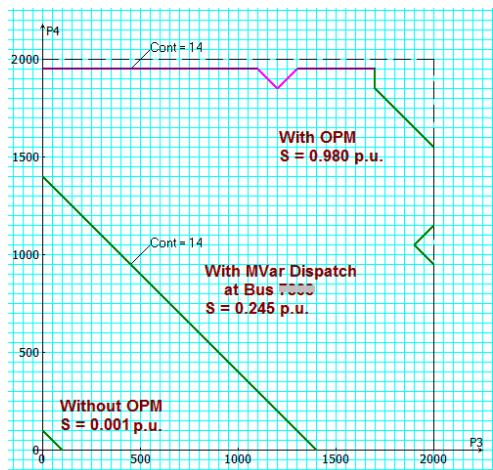


Fig. 15. The Secure Operating Region for Contingency 14 with and without Mitigation Measures

## VI. CONCLUSION

This present paper describes a process for evaluating real-time reliability at EKPC in order to comply with NERC recommendations.

The EKPC objectives for this study are:

- Reduce transmission constraint costs
- Increase power transfer capability
- Provide post-contingency remedial recommendations
- Replace multiple planning software tools
- Adopt as an operational tool

The study showed that the approach introduced in this paper is a very fast method for performing reliability analysis.

The benefits of such analysis include:

- Model reduction unnecessary
  - There is no need to reduce the large planning model into a smaller model for use by operations.
- More thorough analysis
  - Complete AC N-1 contingency analysis in less than 20 minutes on the full model.
- Model power transfers and recommend actions to increase power transfers
- Quickly provides post-contingency results, including remedial actions

- Thorough line request analysis

No need to study the loss of particular N-1 facilities; all may be evaluated

During the first step of analysis, full N-1 contingency study was performed, while monitoring voltage, thermal, and voltage stability constraints. As a result, critical contingencies, bottlenecks (weakest buses & branches) and voltage stability margins were identified. Remedial actions for all post-contingency violations were recommended.

Power transfers were simulated and transfer limits were determined for each contingency, while monitoring voltage, thermal, and voltage stability constraints. Remedial actions to increase power transfers were identified and recommended. The boundary of the secure operating region was computed for each contingency and contingencies were ranked based on the size of the secure operating region.

A study was performed using the EKPC loadflow data to validate the approach.

Because this approach looks very promising, EKPC has decided to continue testing the approach in Transmission planning and Power Delivery Operations. EKPC is likely to replace the existing tools with the approach described in this paper.

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## VIII. BIOGRAPHIES

**Paul Dolloff** (M' 84) received a BS degree in Electrical Engineering from Tenn. Tech. University. His MS and Ph.D. degrees in Electrical Engineering are from VA. Tech. University. Dr. Dolloff's MBA degree is from Morehead St. University. Currently, Paul is an electrical engineer in the Research and Development Department at East Kentucky Power Cooperative. Paul is also an Adjunct Faculty member in the Electrical and Computer Engineering Department at the University of Kentucky.

**Darrin Adams** received his BA degree in Liberal Studies from Transylvania University and his BS degree in Electrical Engineering from the University of Kentucky. Mr. Adams has more than 15 years of experience in the planning and operation of electric utility transmission systems. He is presently the Manager of Transmission Planning at East Kentucky Power Cooperative in Winchester, Kentucky. Mr. Adams is also a registered Professional Engineer in Kentucky.

**Steve Anderson** (M' 90) received a BS degree in Electrical Engineering from the University of Kentucky. Mr. Anderson is a Senior Engineer in the Power Delivery Operations Dept. for East Kentucky Power Cooperative. Steve is also a registered Professional Engineer in Kentucky.

**Michael Vaiman** (M' 91) has over 40 years of power industry experience. He received his MSEE degree from Kaunas Polytechnic University, Lithuania in 1961, Ph.D. degree from Moscow University of Transportation Engineering, Russia in 1969, and D.Sc. degree from St. Petersburg Polytechnic University, Russia in 1986. He was a full professor, Department of Automatic Control and Telecommunications at Moscow University of Transportation Engineering, Russia until 1991. Since 1992 Dr. Vaiman is a President and Principal Engineer at V&R Energy Systems Research, Inc. His main areas of interest are power system stability and control, power flow and optimal power flow analysis, computer modeling of power system networks, selection of remedial actions for stability preservation; dynamic stability analysis.

**Marianna Vaiman** (M' 97) received her BSEE and MSEE degrees from Moscow University of Transportation Engineering, Russia. She has 15 years of experience in power system studies. In 1992 she joined V&R Energy Systems Research, Inc. (V&R), where she is currently Principal Engineer and Executive Vice President. She leads the work in the following areas at V&R: Software Development, Consulting Activities, Research & Development Activities.

**Mark Povolotskiy** received his MS degree in Mathematics & Physics degree from Nezhin State University, Ukraine in 1978 and Ph.D. degree in Physics & Mathematics from Institute for Geophysics, Ukrainian Academy of Science, Ukraine in 1990. Dr. Povolotskiy has over 25 years of R&D experience. His main areas of interest include mathematical modeling of the power system networks, and deterministic and probabilistic approaches to the analysis of the power system. He joined V&R Energy Systems Research, Inc. in 2001, where he is currently Senior Support Engineer working in the areas of Software Support and Consulting Services. He has over 30 published works, including 1 patent.

**Dale Bradshaw** (M' 98) is the President of Electrivation, a firm providing consulting services on power generation and delivery. Mr. Bradshaw has more than 30 years of experience in all aspects of the electric utility business, nuclear, planning, clean coal, fossil generation, renewables, and fossil fuels. He also has experience in technical advancements for improving performance of current operations related to transmission and distribution of electric power, FACTS devices, high temperature superconductivity, Smart Grid systems, grid security, the modern grid, advanced distributed generation, fuel cells, micro turbines, advanced central station options, advanced nuclear power and fuel cycles, coal gasification and coal conversion, environmental control systems, and all aspects of the electric utility business. Mr. Bradshaw is also the CEO of Advanced Coal Technologies. Mr. Bradshaw worked for TVA from 1975 through 2004. He retired from TVA as the Senior Manager of Power Delivery Technologies in 2004.