Eastern Interconnection Reliability Assessment Group

SERC East-RFC

(SER)

Study Procedures Manual

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1.0 INTRODUCTION

As part of the joint Eastern Interconnection Reliability Assessment Group (ERAG) agreement signed by the six reliability regions in the Eastern Interconnection, the SERC East-RFC Steering Committee, under the direction of the ERAG Management Committee, conducts appraisals of the SERC East-RFC interregional system performance. On a regular basis, the SERC East-RFC Seasonal Study Group, under the guidance of the SERC East-RFC Steering Committee, performs the interregional transfer capability studies. The studies, which are used as a means to measure system strength and evaluate system performance, are completed with anticipated operating conditions of the near-term summer and winter peak load conditions.

The SERC East-RFC Near/Long Term Study Group also periodically carries out studies and/or assessments of future system conditions. Such assessments include a review the studies performed by regions, sub-regions, and RTOs. Future system studies analyze the effect of significant system additions and/or system conditions that impact the future operation of the interconnected network may be completed as directed by the Steering Committee, to comply with NERC Reliability Standard TPL-005.

While the scope of seasonal transmission assessments may vary slightly from one year to another, the study objectives and procedures remain relatively unchanged. The scope and procedures of the future system studies are determined by the nature of the specific study, but the general study principles are the same as those of the seasonal transmission assessments. Because of the regular turnover of the Steering Committee's and Study Groups' membership, this study procedures manual will serve as a general guideline to both groups and help bring new participants quickly up to speed on why and how the studies are conducted.

This manual documents the objectives, definitions, security criteria, and procedures that apply to the SERC East-RFC seasonal transmission assessments for interregional transfers and, where applicable, to future system studies. It is intended to provide a general guideline and should not restrict the scope and procedure of a given study.

2.0 STUDY OBJECTIVES

For the summer and winter transmission assessments and the future studies, the main objective is to appraise the performance of the interconnected bulk power network among the SERC East-RFC systems from an overall interregional standpoint under anticipated system conditions. Additionally they serve as a way to measure system strength and determine if any trends in transfer capability are apparent. The intent of the appraisal is to provide assurance that system developments and operating procedures within each region are being properly coordinated so they do not adversely affect other regions. As required, the appraisal may be extended to assess the effects of system condition changes that are deemed to have a good possibility of occurrence, e.g., if supported by operating experience. Study objectives for future system studies are similar to those of the seasonal transmission assessments with modifications and additions to address the specific area of investigation.

3.0 STUDY SCOPE

The Steering Committee approves the study scope that is prepared by the Study Group Chairman. Normally, the study scope covers the following basic items:

1. Determine the incremental and total non-simultaneous transfer capabilities between PJM, MISO, SERC East (VACAR and CENTRAL Sub-regions of SERC), VACAR, and CENTRAL (imports and exports), up to an appropriate test level. Extrapolation for informational purposes beyond the test level is acceptable up to the first limit when that limit does not exceed 10% of the test level. In this case the FCTTC will be reported as XXX+ or >XXX, where XXX is the transfer test level.
2. Calculate transfer response factors for key interfaces and key facilities for selected economy/emergency transfers.
3. Calculate the effect on transfer capability of selected simultaneous transfers for key facilities.
4. Calculate and plot the effect of simultaneous transfers.
5. Examine the effects of selected non-SERC East-RFC transfers on SERC East-RFC transfer capabilities

The above study scope may be expanded to include an assessment of variations in system condition and estimate the effect of major facility additions. Nevertheless, the study scope is restricted primarily to the appraisal of interregional transfers under steady-state conditions. The Study Group does not normally conduct appraisals of stability performance. If and when such a need arises, a separate dynamics Study Group is established and a study scope is prepared.

When the terms “selected” or “key” are used in the scope, the facilities and transfers are either determined from past studies and testing or are well known to the regional representatives as potential problem areas.

4.0 GENERAL PROCEDURES AND ASSUMPTIONS

The Steering Committee approves the general guideline for study procedures and assumptions normally provided by the Study Group that include:

1. Interregional and intra-regional base transfer levels including wheeling between various systems.
2. Recommended upper test levels of interregional and sub-regional transfer cases.
3. Phase Angle Regulator (PAR) settings.
4. Transfer cases for which the transfer response factors are to be calculated.
5. A list of sensitivity tests when appropriate.

Using this general guideline, the Study Group establishes a responsibility chart and work plan to meet the required schedule. Linear analyses are performed to establish incremental transfer capabilities based on thermal considerations. These thermal transfer capabilities are then checked against reactive limitations and revised as required. The combined results are tabulated and the Study Group submits a complete draft report to the Steering Committee for review. More detailed study procedures are discussed in the following sections. Definitions of some of the terms used in the discussion are provided in Appendix A.

5.0 BASE CASE

Each seasonal operating study and future study begins by using a MMWG power flow base case. Procedures and guidelines used to create the MMWG models are detailed in the "ERAG Multiregional Modeling Study Group Procedural Manual" which can be downloaded at http://erag.info/MMWG.aspx. One seasonal ERAG base case is created for use in all the interregional seasonal reliability studies. Trial 1 of the seasonal trans-mission assessment base case is usually released about five months before the seasonal transmission assessment scheduled completion date.

From the Trial 1 case, a fine-tuned case is developed which includes the modeling of coordinated interregional and intra-regional base transfers, major generation and trans-mission additions and outages, and other changes, and market dispatches for PJM and MISO. This base case development is conducted through the MMWG coordinator.

5.1 Alternate Base Cases

Alternate base cases may also be developed for sensitivity testing of specific operating conditions, such as facility additions, long-term outages, system load variation or additional base transfers that are not already modeled in the base case.

5.2 Phase Angle Regulator (PAR) Settings

Branchburg-Ramapo

In the transmission assessments, the Ramapo PAR setting is determined in accordance with the general guideline provided in a PJM Interconnection Dispatcher Memorandum, No. 465, titled "Ramapo PAR Operating Instruction." In the base case, the Ramapo PARs are set at a level that reflects the expected total transfers between NYPP and PJM.

In actual operation, the flow is typically south to north (from Branchburg to Ramapo). Because of this bias, during modeling the bandwidth (100 MW) is usually set fully towards NYPP up to the 1,000 MW limit of the PARs. Where test levels over and above the base transfer are modeled, for transfers involving PJM Mid-Atlantic and NYPP, the Ramapo PAR setting must be revised.

The proper PAR settings are generally determined as follows:

Ramapo PAR Setting = (0.61 x Total PJM to NYPP Transfer) + Bandwidth

For example, if in the base case the total transfer from PJM to NYPP is 500 MW the PARs would be set to 305 + 100 = 405 MW from PJM to NYPP.

High levels of transfer from PJM to NYPP in the base case, by the above calculation, would dictate that the Ramapo PAR should be set at 1,000 MW from PJM to NYPP in the base case. In this case the modeling of the bandwidth set fully to NYPP is relaxed so that the Ramapo PAR is modeled at a level in the base case not to exceed 850 MW from PJM to NYPP.

The above general guideline also applies to those tests made for voltage analysis.

Public Service Wheel

The Orange and Rockland-Public Service-Consolidated Edison of New York PARs should be set to maintain the PS-Con Ed Wheel. Combined net flows into northern New Jersey on the two South Mahwah-Waldwick ties should be 1000 MW. The combined net flows out of New Jersey into New York on the two Hudson-Farragut lines and the Linden-Goethals line should be 1,000 MW.

Michigan-IMO Pars

The Michigan-IMO interface is expected to be controlled by four phase angle regulators. In the base case, the operation of these PARs may be modeled to control flow to schedule on the interface.

6.0 STUDY CRITERIA

Transfer capabilities are determined with simultaneous observance of the security criteria specified by all the study regions. Since stability performance is normally not appraised, the security criteria applied are normally restricted to equipment loadings, voltage constraints and observance of established interface flow limits.

Different security criteria exist between regions and between utility members within a region. In general, normal and emergency system criteria are applied as appropriate for the system conditions tested.

The SERC East-RFC transmission assessments are usually intended to appraise and assess system transfer capability as a measure of system strength; therefore, system security criteria are applied accordingly. Established operating procedures, which are deemed to have an impact on equipment loading, are also considered and simulated as required.

6.1 Contingency Criteria

For all regions, the loss of transmission elements or significant generation due to a single contingency is observed. Selected single contingencies involving transmission elements of 100 kV and above are simulated, as specified in NERC Reliability Standard TPL-002. When appropriate, contingencies involving transmission elements less than 100 kV and smaller generating units may also be simulated. Properly formatted contingency lists are typically used from study to study. These lists are updated prior to commencement of each study. Other contingencies may be studied as directed by the Steering Committee to assure compliance with NERC Reliability Standard TPL-005.

6.2 Equipment Loading (Thermal) Criteria

In all regions, the bulk electricity supply systems should be operated in such a manner that all transmission equipment loadings are within the normal continuous ratings pre-contingency, and within the applicable emergency ratings following a contingency. The facility owner defines the ratings, or an agreed to reliability rating that is determined between facility owners when the facility in question is an interconnection or tie line.

Different categories of applicable emergency ratings exist in different regions. For the purpose of the SERC East-RFC transmission assessments, the ratings criteria below are usually applied in establishing emergency transfer capabilities. It should be noted that tie line ratings should be coordinated between companies so that different ratings on a line or transformer between two regions are not created. Any changes should be made to the tie line database used by the regional coordinator during the base case development process. As a rule of thumb, the lower ratings are normally applied when the analysis is performed.

Table 1 provides a summary of the thermal criteria applied during the SERC East-RFC transmission assessments.

SERC
Each participating SERC member company has developed normal and emergency ratings for its facilities which are consistent with its own operating requirements and practices within its area.

RFC
Each RFC member company has developed normal and emergency ratings for its facilities that are consistent with its own operating requirements and practices within its area.

6.3 Voltage Criteria

Results from voltage analysis indicate several of the transfers may be limited by voltage constraints at various locations in the PJM Extra High Voltage (EHV) network. Operating experience and studies have indicated that several 500 kV substations can sustain low voltages during heavy transfers in the east-to-west and west-to-east direction. Operating procedures have been established to control the level of transfers so that the threat of voltage collapse is mitigated.

PJM Voltage Criteria
PJM operating criteria specify a maximum voltage drop at the 500 kV system from pre contingency to post-contingency conditions. The voltage drop criteria is bus specific. For the majority of the EHV network the voltage drop criteria is 5%. The voltage drop limit is often adjusted in daily operations to reflect the overall rate of change of the postulated voltage drop.

Power flow across, and voltage levels on, various PJM interfaces are monitored as a proxy of total system transfers. These interface flows are reduced if a postulated voltage drop exceeds a given threshold. The 500 kV lines used to define the PJM interfaces are:

PJM Western Interface
Keystone-Juniata 500 kV
Conemaugh-Juniata 500 kV
Conemaugh-Hunterstown 500 kV
Doubs-Brighton 500 kV

PJM Eastern Interface
Wescosville-Alburtis 500 kV
Juniata-Alburtis 500 kV
TMI-Hosensack 500 kV
Peach Bottom-Limerick 500 kV
Peach Bottom-Keeney 500 kV

PJM Central Interface
Keystone-Juniata 500 kV
Conemaugh-Juniata 500 kV
Conastone-Peach Bottom 500 kV

AP South Interface
Mt. Storm-Doubs 500 kV
Mt. Storm-Greenland Gap 500 kV
Mt. Storm-Valley 500 kV

Bedington-Black Oak (AP North) Interface
Bedington-Black Oak 500 kV

AEP Voltage Criteria
AEP voltage criteria specify limits on both the actual voltage level and the voltage drop at each of its busses 138 kV and above. Typically, the minimum voltage for AEP stations is 95% with all facilities in-service and 92% during contingencies. The minimum voltage for stations with generators connected will reflect the minimum allowable generator voltage and will be specific to each station. In addition, AEP limits voltage drops to no more than 10%. The maximum voltage is specific for each station depending on the equipment capabilities within the station.

7.0 GENERAL METHODOLOGY

7.1 Linear Assessment

The ability of the bulk power system to transfer power from one region to another is often constrained by the thermal capability of transmission elements or established interface flow limits for various normal and contingency conditions. The most commonly used measure of transfer capability is the First Contingency Incremental Transfer Capability (FCITC), as defined in the May, 1995 North American Electric Reliability Council publication “Transmission Transfer Capability”.

Another commonly used term defined in the NERC publication is the First-Contingency-Total-Transfer-Capability (FCTTC) which is the algebraic sum of FCITC and the base transfer.

To efficiently determine the thermal and/or interface flow limitation of various transfers, a linear power flow solution is used. Linear power flow (dc power flow) is a non-iterative numerical technique for the approximate but rapid calculation of power flow solutions. By ignoring reactive power flow and changes in voltage magnitudes, numerous contingencies can be considered for a minimal in-vestment in computer time. Employing a linear power flow solution and the superposition of network distribution factors (LODF and OTDF), several software packages are available which provide thermal transfer limits for a wide number of selected monitored facilities and contingencies. The one currently used in SERC East-RFC analysis is: Power Technology Inc. (PTI) MUST – Managing and Utilizing System Transmission

7.1.1 Basic Linear Calculation Method

Three distribution factors, defined in the NERC "Transmission Transfer Capability" publication, are used to determine the FCITC. They are the Power Transfer Distribution Factor (PTDF), the Outage Transfer Distribution Factor (OTDF) and the Line Outage Distribution Factor (LODF).

An incremental change in transfer between two areas causes a change in the loading of the circuits in the path of the transfer. The OTDF is the percent of transfer that flows on any specific circuit in the network with an element out. This incremental power flow must be superimposed on the pre-transfer flow on the specific circuit, resulting in a net increase or de-crease in circuit loading. Since the test network is static, the power in-crease in the circuits in the network is proportional to the transfer and distributed by the network impedances.

Assuming the outage of a given circuit in a network, the LODF is the per-cent of the pre-outage power flow which has been carried by the removed circuit and now flows on any selected circuit remaining in service. This incremental power flow is superimposed on the pre-outage flow on this specific circuit, resulting in a net increase or decrease in circuit loading.

The superposition of the PTDF of a specific circuit and the contributing PTDF of the removed facility (contingency limitation) give the Outage Transfer Distribution Factor (OTDF).

The use of distribution factors assumes that the network will act in a linear fashion. If transfer or circuit outage results in low voltage at the terminals of a particular circuit or the angle across the circuit are large, the circuit will carry less than its proportional share of the change power flow. Therefore ac power flow check cases should be used to verify the transfer limit.

The two examples below show how the FCITC is calculated:

<u>Example 1: Pre Contingency Limitation</u>

Transfer:	Non-PJM-VACAR to PJM
Transfer Test Level:	2000 MW
Monitored Facility:	Pruntytown - Mt. Storm 500 kV line
Rating of Monitored Facility:	2,600 MW, 24 hours system normal
	2,975 MW, long-term emergency

1) Results of Power Flow Simulation:

	Base Flow	Transfer Flow
Pruntytown Mt. Storm 500 kV line	1,900 MW	2,328 MW

2) Transfer Distribution Factor:

PTDF = [Transfer Flow   Base Flow] / [Transfer Level]

PTDF = [2,328 – 1,900] / [2,000]

PTDF = 0.214

NITC = [Normal Rating of Monitored Facility   Base Flow of Monitored Facility] / (PTDF)

NITC = (2,600 – 1,900) / (0.214)

NITC = 3,271 MW

Example 2: Contingency Limitation

Transfer:	Non-PJM-VACAR to PJM
Transfer Test Level:	2,000 MW
Monitored Facility:	Pruntytown-Mt. Storm 500 kV line
Contingency:	Black Oak-Bedington 500 kV line
Rating of Monitored Facility:	2,600 MW, 24 hours system normal 3,031 MW, long-term emergency

1) Results of Power Flow Simulation:

	Base Flow	Transfer Flow	Post-Contingency Transfer
Pruntytown-Mt. Storm 500 kV line:	1,900	2,328	3,203
Black Oak-Bedington 500 kV line:	1,678	1,979	-------

2) Calculation of Power Transfer Distribution Factors (PTDF):

PTDF = [Transfer Flow - Base Flow] / Transfer Level

a) Pruntytown-Mt. Storm 500 kV: PTDF = (2,328 - 1,900) / (2,000)
PTDF = 0.214

b) Black Oak-Bedington 500 kV: PTDF = (1,979 - 1,678) / (2,000)
PTDF = 0.151

3) Calculation of Line Outage Distribution Factor (LODF):

LODF = [Post-Contingency flow on monitored facility – Pre-Contingency flow on monitored facility] / [Pre-Contingency flow on facility out]

LODF of Pruntytown-Mt. Storm 500 kV for loss of Black Oak-Bedington 500 kV

LODF = (3,203 - 2,328) / 1,979

LODF = 0.442

4) Outage Transfer Distribution Factor (OTDF):

OTDF = Superposition of the PTDF of monitored facility and the contributing PTDF of the facility out

OTDF = [PTDF of Pruntytown-Mt. Storm 500 kV] + (LODF) (PTDF of Black Oak-Bedington 500 kV)

OTDF = 0.214 + (0.442)(0.151)

OTDF = 0.281

5) Post-Contingency Base Flow on Monitored Facility:

[Base Flow] + (LODF) [Base Flow of Facility Out]

= 1,900 + (0.442)(1,678)

= 2,642 MW

FCITC = [Limiting Rating of Monitored Facility – Post-Contingency Base Flow Monitored Facility] / (OTDF)

FCITC = [3,031 – 2,642] / (0.281)

FCITC = 1,384 MW

7.1.2 Study Procedure

Below are the steps used by the Study Group to calculate the FCITC and/or NITC of the various transfers.

I. Establish a base condition.
II. Develop outage and monitored line list.

III. Develop generation dispatches for each transfer to be simulated.
IV. Calculate transfer capabilities, FCITCs and FCTTCs, where applicable.
V. Test for voltage limitations using ac power flows.

A more detailed explanation of each step follows:

I. ESTABLISH A BASE CONDITION
An evaluation of transfer capability is based on a simulation of the power system performance. The power system model represents a single “snapshot” of the condition of the system. Different patterns of demand and generation cause variation in transfer capabilities on an hour-by-hour basis. The transfer limit determined in the study should therefore be considered representative rather than definitive.

The model used is developed from the MMWG seasonal base case. This case is modified by the MMWG Coordinator to include additional contracted transfers and PJM and MISO market dispatches. This ERAG base case is used for all the interregional seasonal studies.

II. DEVELOP OUTAGE AND MONITORED LINE LIST
A list of contingencies (lines and transformers), along with a list of key lines and interfaces to be monitored and/or taken out, are updated from the previous year’s list or created by the Study Group for each study. The list is reviewed at the be-ginning of each study to check for completeness and accuracy.

III. DEVELOP GENERATION DISPATCHED FOR EACH TRANSFER TO BE SIMULATED
The import dispatch methodology is based on a “generation deficiency” scenario that is expected to stress the system. In this scenario, a situation is simulated in which critical generating facilities within one system are unexpectedly taken out, causing that system to request back-up power from a neighboring system. The neighboring system, in response to the request, increases its generation to a new level in order to meet the deficit system’s needs, in addition to its own generation requirements. Therefore, when modeling a transfer, the exporting system picks up generation according to economics. The importing system, on the other hand, reduces generation at certain plant(s) in order to represent a pessimistic, but realistic, transfer scenario. Care must be taken when selecting generation on or near the interface between two systems so as not to bias the results of the study. When insufficient generation reserves exists to model an export, load may be reduced in control areas remote from the study interface and those areas may contribute to the export in order to stress the transmission system.

IV. CALCULATE TRANSFER CAPABILITIES, FCITCs AND FCTTCs, WHERE APPLICABLE
The incremental non-simultaneous transfer capabilities are calculated for transfers among markets and sub-regions. Additional transfers may be analyzed if deemed necessary by the Steering Committee.

Multiple FCITC limits are reported for each transfer condition. The intent is to provide a broad overview of where potential limitations could occur on the bulk power transmission system.

Transfer capabilities are usually listed in ascending order. After reporting the first limit, subsequent limits are reported only if neither the limiting facility nor the contingency has been previously reported. An abbreviated list is given in each report which is titled Table 1.

V. TEST FOR VOLTAGE LIMITATIONS USING AC POWER FLOWS
AC load flows may be used to verify the FCITC for voltage-based limits and to check for an acceptable voltage profile at the FCITC limit. As a general rule, the following steps should be used:

- Set up an ac test case using the closest previously established dispatch at the first limit level.
- Apply the designated contingencies.
- Apply the appropriate voltage criteria.

7.1.3 Study Guideline

Distribution Factor Cutoff
A facility is generally not reported as limiting if the Line Outage Distribution Factor (LODF) and/or the Outage Transfer Distribution Factor (OTDF) in response to a transfer are less than 3.0%.

This cutoff point has been established on the basis that facilities exhibiting a low response to transfers are generally electrically distant from the main transfer path or are not part of the bulk transmission system. Since transfer capability and FCITCs are inversely proportional to the transfer factor, FCITCs limited by low-response facilities will be very sensitive to circuit pre-loading, local load and generation patterns, and nearby equipment out-ages. FCITCs calculated may not be representative of typical interconnected system strength and reducing or limiting interregional transfers may be a very ineffective way to relieve the facility overload.

The cutoff should be viewed as a guideline rather than a rigid criterion. For transfers restricted by pre-contingency operating conditions, the cutoff applies to the Power Transfer Distribution Factor (PTDF) on the limiting component.

Extrapolation
Extrapolation above the test level may result in the assumption that generators used in the transfer dispatch may either exceed their rated capability or be dispatched to below zero generation; in reality additional generators will be dispatched to facilitate transfers up to the FCITCs. Extrapolation for informational purposes beyond the test level is acceptable up to the first limit when that limit does not exceed 10% of the test level. In this case, the FCTTC will be reported as XXX+ or >XXX, where XXX is the transfer test level.

<u>Rounding Off Transfer Limits</u>
Transfer capabilities are rounded to the nearest 50 MW. For example, a transfer capability of 2,945 MW would be reported as a limit of 2,950 MW. The midpoint case of 2,925 MW would be reported as 2,900 MW.

<u>Operating Procedures</u>
When a limiting facility is identified and an operating procedure can effectively remove it as a limit, the table of transfer capabilities should clearly show whether an operating procedure could be used to alleviate the limit and report the next higher transfer capability.

If a facility for which operating procedures exist limits a transfer, then the limitation may be removed by noting the operating procedure. These types of operating procedures usually include opening a restrictive line pre-contingency or automatic opening of an overloaded circuit.

For example, the Seneca-Krendale 138 kV interconnection between AP and OE (First Energy) can be opened when necessary in order to alleviate anticipated heavy loading in the event of a Wylie Ridge-Cabot 500 kV contingency.

Verification of the operating procedures is usually left to the regions. When a significant limit may be eliminated due to an operating procedure, the Study Group does verification.

7.1.4 MUST Options

The following MUST options should be used. The rest of the options remain at default.

Phase shifters in the base case and contingencies:	Constant flow
Report base case violations with FCITC:	Yes
Base case rating:	Rating A
Contingency case rating:	Rating B
Convert branch ratings to estimated MW:	No
Distribution factor cutoff:	Set at .025 but report values above .03
Apply to FCITC reports:	Yes
Apply to Violation analysis:	Yes
Contingency ID reporting:	Labels + Events
Bus input/output:	By number

7.2 Voltage Based Limits and Voltage Assessments

For transfers that may be restricted by established voltage-based transfer limits, FCITCs with observance of these limits will be calculated and reported.

At present, all known voltage-based limits to interregional transfers examined in the SERC East-RFC studies occur on interfaces within the PJM system.

Appendix C of this manual provides a detailed description of the methods with which the PJM voltage limits are calculated. The appendix will be updated as needed if other voltage-based limitations are made known, or if changes to existing criteria or interface definitions are made.

PJM reactive limits are examined for all PJM importing scenarios. All these tests are made with ac analysis. No further verification is required.

In addition, a list of specified contingencies will be run on a base case which models transfers at a level as close to the FCITC levels as possible with available dispatch data. Voltages will then be analyzed using the appropriate voltage criteria.

7.3 Effect of Simultaneous Transfers

In addition to FCITC and various system response factors, the effect of simultaneous transfers is also studied and results presented. The effects on SERC East-RFC transfers of simultaneous non-SERC East-RFC transfers is analyzed using the MUST Parallel Transfer analysis. These plots are included in the report.

7.4 Extreme Contingency Testing

Reference: NERC TPL Reliability Standards, Table I.

Category C – Event(s) resulting in the loss of two or more (multiple) elements.

Category D - an extreme event resulting in the loss of two or more (multiple) components or cascading out of service (i.e. bus section, double circuit tower, generator, transmission line, transformer, tower line, all trans-mission lines in a common right of way, a substation and all lines at a particular voltage level, all generation with a given plant, a large load or load center).

For the purpose of the SERC East-RFC study, the Steering Committee believes that, generally, if the results of tests listed under Category D have acceptable values then all less severe categories should generally produce acceptable results as well.

When so directed by the SERC East-RFC Steering Committee, the SERC East-RFC Study Group will perform the following tests:

7.4.1 For each of the first limits listed in Table 1.1, create a separate base case at the FCITC transfer level.

7.4.2 Run an ac case with the contingency listed in Table 1.1, check to see that no lines are above their respective thermal capability.

7.4.3 Review the configuration and loading of the facilities in the proximity of the contingency.

7.4.5 Take the contingency judged to be the next most severe yet reasonable. For example assume that one of the breakers required to clear the initial contingency has a stuck pole, or relay overreaches, resulting in the loss of an adjacent component in a ring bus or breaker and one-half configuration.

7.4.6 Run an ac case and evaluate the system's performance, evaluate the test results to see that conditions are acceptable. If specific limits are not known, generic values may be applied (no line exceeds 125 % of its respective emergency rating or voltage is depressed below 0.85 pu).

7.4.7 If any of the above values are exceeded remove the over loaded facility and/or drop the load/generation at the designated bus and re-run the ac test. Continue this evaluation until either no more over loads or low voltage conditions are observed, the model diverges or conditions indicate that widespread cascading of overloads is occurring or voltage collapse is inevitable.

7.4.8 Report the results in the Regional Appraisal Section of the report. Discussion should include, but not be limited to, low voltages, line overloads and angular separations on the bulk power facilities in the affected area.

8.0 WORK SCHEDULE

To perform an operating study, a timetable, a work schedule, and the work assignment are made by the Study Group chairman. This is done prior to or as the base case is being created. As part of the ERAG base case update process, the base case is checked to be sure that it is accurate and up-to-date. The final ERAG base case should be completed just prior to beginning the study.

The Seasonal Study Group initiates the operating study about four months prior to the expected publication date of the report, i.e., early February for a summer study and early August for a winter study. The Steering Committee approves the study scope and procedure at their October meeting for the summer study and at their April meeting for the winter study. The Seasonal Study Group may modify the scope and procedure with Steering Committee approval. The Seasonal Study Group also provides a study schedule which lists the dates they plan to review the preliminary results and the preliminary draft report and the date when they plan to mail a draft to the Steering Committee for final approval. The Study Group chairman develops a Responsibility Matrix and Work Schedule designed to meet these study schedule deadlines. An example Responsibility Matrix and Work Schedule is provided in Appendix B.

The initial work for the group involves developing the data to perform the thermal assessment. A list of monitored elements and a list of contingencies must be produced rather early. The Study Group chairman should coordinate what form the Study Group members would like to receive the information. Previous lists can be used as a good starting point. Before the computer analysis can begin, generation participation factors must be determined for each transfer stated in the scope. Individual members representing their areas/regions usually provide these factors.

Once the thermal transfer limits are determined, ac power flows may be performed for accuracy verification and voltage assessment.

The responsibility for completing the tables and diagrams for the report is determined by the Study Group chairman. The final form of the report is largely the responsibility of the Steering Committee. The Study Group should make suggestions to changes in the text and supply proposed text on new information that affects the results of the study.

This procedure manual is distributed to all SERC East-RFC Study Group and Steering Committee members along with the chairmen of the ERAG Management Committee, the RFC-NPCC Steering Committee, and the MRO-RFC-SERC West-SPP Steering Committee.

APPENDIX A

Definitions of Terms and Interfaces

Transfer Capability Discussion

The transfer capabilities determined in this report were defined in May 1995 by the North American Electric Reliability Council (NERC) publication "TRANSMISSION TRANSFER CAPABILITY- A Reference Document for Calculating and Reporting the Electric Power Transfer Capability of Interconnected Electric Systems" as follows:

Normal Incremental Transfer Capability (NITC)
The amount of electric power, incremental above normal base power transfers, that can be transferred between two areas of the interconnected transmission systems under conditions where pre-contingency loadings reach the normal thermal rating of a facility prior to any first contingency transfer limits being reached. When this occurs, NITC replaces FCITC as the most limiting transfer capability.

First Contingency Incremental Transfer Capability (FCITC)
The amount of electric power, incremental above normal base power transfers, is that which can be transferred over the interconnected transmission system in a reliable manner, based on the following conditions:

1. For the existing or planned system configuration, and with normal (pre-contingency) operating procedures in effect, all facility loadings are within normal ratings and all voltages are within normal limits,

2. The electric systems are capable of absorbing the dynamic power swings, and remaining stable, following a disturbance that results in the loss of any single electric system element, such as a transmission line, transformer, or generating unit, and

3. After the dynamic power swings subside following a disturbance that results in the loss of any single electric system element as described in 2 above, and after the operation of any automatic operating systems, but before any post-contingency operator-initiated system adjustments are implemented, all transmission facility loadings are within emergency ratings and all voltages are within emergency limits.

First Contingency Total Transfer Capability (FCTTC)
The total amount of electric power (net of normal base power transfers and first contingency incremental transfers) that can be transferred between two areas of the interconnected transmission systems in a reliable manner based on conditions 1, 2, and 3 in the FCITC definition above.

Excluded Limitations
Transfer capability limits are determined by the overall interconnected systems. When the loadings of certain lower voltage electric facilities restrict calculated transfer capability, these transfer capabilities and their limiting facilities should be reported. For consistency, it is recommended that such lower voltage limitations be excluded from the analysis only on the basis of one of the following two conditions:

1. An established and documented operating procedure exists for eliminating the overload or restrictive condition. In addition, no restrictive conditions will be placed on the implementation of these procedures. For these situations, transfer capability should be documented as having been calculated with the operating procedure in effect, or

2. The restrictive or limiting facility has minimal or no adverse effect on the reliability of the electric supply systems (i.e., the outage of the facility is not likely to lead to widespread or cascading outages). System facilities having a distribution or response factor of 3% should generally be excluded from the calculation of transfer capability.

Where transfer capability values are based on the exclusion of such restrictions, this exclusion should be documented as a part of the study results.

Glossary of Acronyms

FCITC	First Contingency Incremental Transfer Capability
FCTTC	First Contingency Total Transfer Capability
GSRF	Generation Shift Response Factor
LODF	Line Outage Distribution Factor
LPF	Linear Power Flow
LTE	Long-Term Emergency rating
NITC	Normal Incremental Transfer Capability
NUG	Non-Utility Generator
OTDF	Outage Transfer Distribution Factor
PAR	Phase Angle Regulator
PTDF	Power Transfer Distribution Factor
STE	Short-Time Emergency rating

Definitions of Terms

Availability - The condition of an element that is capable of service whether or not it is actually in service.

Bulk Electric System - The aggregate of electric generating plants, transmission lines, and related equipment. The term may refer to those facilities within one electric utility or within a group of utilities in which the transmission lines are interconnected.

Bus - A bus is a conductor or group of conductors that serve as a common connection for two or more electric circuits within a station.

Capacity Emergency - A capacity emergency exists when a system's or pool's capacity, plus firm purchase from the interconnection, to the extent available or limited by transfer capability, are inadequate to meet its demand plus its regulating requirements.

Contingency – A contingency is an unexpected event, usually the loss of one or more elements, which affects the power system at least momentarily.

Deficiency Scenario - A deficiency is considered to exist if generation becomes unavailable during a time when the system load is peaking or near peak.

Element - Any electric device with terminals which may be connected to other electric devices, usually limited to a generator, transformer, circuit breaker, or bus section.

Emergency - An emergency is considered to exist in an area or region if firm load may have to be shed because sufficient power or energy is unavailable in that area or region after due allowances for purchases.

Energy Emergency - An energy emergency exists when a system or pool does not have an adequate fuel supply (including water for hydro units) to provide its customers' expected energy requirement over a given period.

FCITC - First Contingency Incremental Transfer Capability (defined above) is the incremental transfer capability above the transfers modeled in the base case.

FCTTC - First Contingency Total Transfer Capability is the algebraic sum of the FCITC and the base case region-to-region transfer.

Firm Load - The power provided to customers that is continuously available on demand and which is subject to interruption only under extreme circumstances.

In-Service - A term used to indicate a device is connected to the power system and fulfilling its function.

Limiting Contingency - The contingency that establishes the transfer capability.

Limiting Element/Facility - The element/facility that is either at its appropriate rating or would be following the limiting contingency and, as a result, establishes the transfer capability.

LLF - Linear Power Flow (dc Power Flow) is a non-iterative numerical technique for the approximate but rapid calculation of power flow solutions. By ignoring reactive power flow and changes in voltage magnitudes, numerous contingencies or alternate base cases can be considered for a minimal investment in computer time. By employing a linear power flow solution and the superposition of network distribution factors (LODF and PTDF), several software packages are available which provide a rapid calculation of the thermal transfer limits for a wide number of selected monitored facilities and contingencies. The one currently used in SERC East-RFC analysis is: Power Technology Inc. (PTI) MUST – Managing and Utilizing System Transmission

Load - The amount of electric power delivered or required at any specified point or points on a system.

LODF - Line Outage Distribution Factor: Percentage of flow on Line A, which is transferred to Line B for the loss of Line A.

Operating Limits - The maximum value of the most critical system operating parameter(s) which meets: (a) pre-contingency criteria as determined by equipment loading capability and acceptable voltage conditions; (b) transient performance criteria; (c) post-contingency loading and voltage criteria.

OTDF - Outage Transfer Distribution Factor: Resultant PTDF with an LODF applied.

Outage - A device is in an outage state if it is not connected to the electric system and fulfilling its designed function.

Overload - A condition wherein electric equipment is carrying current in excess of its applicable rating.

Phase Shifting Transformer - A transformer that advances or retards the phase angle relationship of one circuit with respect to another to control power flow.

Protective Relay - A relay whose function is to detect defective lines or apparatus or other power system conditions of an abnormal or dangerous nature and to initiate appropriate control circuit action.

PTDF - Power Transfer Distribution Factor (or Generation Shift Factor): Percentage of the change in generation between two areas (net change = 0), appearing on any specific line.

Region - A Region is one of the NERC Regional Entities.

Schedule - A statement prepared in advance detailing a plan designating time, specified values, etc., for future action or operation.

Single Element Contingency - A contingency involving the loss of one element.

Stability - Stability is the ability of a power system to maintain a state of equilibrium during normal and abnormal system conditions or disturbances.

System - A combination of generation, transmission, and distribution components comprising an electric utility or group of utilities is considered a system.

System Operator - A person who operates the electric system is a system operator.

Tie Line - A circuit connecting two or more power systems.

Transfer Capability - An operating limit relating to the permissible power transfer between specified areas of the transmission system.

Wheel - The use of the transmission facilities of one system to transfer power of and for another system.

References
NERC Operating Manual

Definition of Interfaces

PJM Western Interface
Keystone-Juniata 500 kV
Conemaugh-Juniata 500 kV
Conemaugh-Hunterstown 500 kV
Doubs-Brighton 500 kV

PJM Eastern Interface
Wescosville-Alburtis 500 kV
Juniata-Alburtis 500 kV
TMI-Hosensack 500 kV
Peach Bottom-Limerick 500 kV
Peach Bottom-Keeney 500 kV

PJM Central Interface
Keystone-Juniata 500 kV
Conemaugh-Juniata 500 kV
Conastone-Peach Bottom 500 kV

AP South Interface
Mt. Storm-Doubs 500 kV
Mt. Storm-Greenland Gap 500 kV
Mt. Storm-Valley 500 kV

Bedington-Black Oak (AP North) Interface
Bedington-Black Oak 500 kV

APPENDIX B

Sample Schedule, Scope and Procedure

SERC EAST-RFC (SER) 2008 WINTER STUDY GROUP ASSIGNMENTS

COMPUTER WORK	RESPONSIBLE PERSON(S)	COMPLETION DATE
ERAG 2008 Winter Base Case Finished	MMWG	8/15/2008
Monitored & Line Outage Files, MUST Generator Dispatches	All to H. Reiter	8/22/2008
Linear Analysis using MUST	H. Reiter	8/29/2008
PJM Voltage Limit AC Analysis	H. Reiter	8/29/2008
ANALYSIS AND REPORT		
Table A-1 Comparison of Base Case Transfers	J. Idzior	9/8/2008
Table A-2 Major Facility Changes-Generation	All to J. Idzior	9/8/2008
Table A-3 Major Facility Changes-Transmission	All to J. Idzior	9/8/2008
Table A-4 Major Facility Changes-Transformers	All to J. Idzior	9/8/2008
Table A-5 Extended Generator Outages	All to J. Idzior	9/8/2008
Table A-6 Generation Modeling Changes	J. Idzior	9/8/2008
Base Case Interchange Schedule	C. Shaffer	9/8/2008
Table 1-FCITCs for 2008 Winter Study	H. Reiter	9/8/2008
Table 1A Sensitivity Analysis	J. Idzior	9/8/2008
Table 2-Comparison of FCITCs and FCTTCs for Transfers	J. Idzior	9/8/2008
Figure 1-Non Simultaneous Interregional Transfers	J. Idzior	9/8/2008
Figures 2A-2D-Plots of Simultaneous Incremental Transfer Capability	S. Shealy	9/8/2008
Figure 3A-3H - Plots of Non-SER ITC	S. Shealy	9/8/2008
Figures A-1 & A-2 Tie Line Flow Diagrams	J. Idzior	9/8/2008
Figure B-1 Transmission Interfaces Monitored	PJM Review	9/8/2008
Table B-1 Key Facilities Index	J. Idzior	10/13/2008
Appendix C - Transfer Dispatches	All to J. Idzior	9/8/2008
SERC East Appraisal	S. Shealy	10/13/2008
CENTRAL Appraisal	S. Cullom	10/13/2008
VACAR Appraisal	P. Darden	10/13/2008
MISO Appraisal	J. Idzior	10/13/2008
PJM Appraisal	H. Reiter	10/13/2008
Draft Report to Working Group	J. Idzior	9/22/2008

SERC EAST-RFC STUDY SCOPE

2008 WINTER OPERATING STUDY

1. Using the ERAG approved seasonal study base case development process, develop 2008 winter base case model that includes all scheduled firm capacity backed transactions. PJM will provide the base case dispatch for the expanded PJM footprint. MISO will provide the base case dispatch for that area.

2. Using this base case, determine the thermal regional and sub-regional First Contingency Incremental Transfer Capabilities (FCITCs) for system transfers determined by the Study Committee (see Procedures #2).

3. Determine voltage limits to selected system transfers using the PJM Voltage Drop Criteria.

4. Determine the effect on selected areas of the study system of significant simultaneous transfers.

5. As a sensitivity analysis, determine FCITCs for transfers from SERC East and from MISO to PJM West, PJM Mid-Atlantic, and PJM South.

SERC EAST-RFC STUDY PROCEDURE

2008 WINTER OPERATING STUDY

Note: SERC East is VACAR and CENTRAL.

1. Participate in the ERAG approved 2008 winter study base case development process.

2. Using linear analysis on the ERAG common base case, determine the First Contingency Incremental Transfer Capabilities (FCITCs) for the following regional and sub-regional transfers:

    - MISO to PJM
    - PJM to MISO
    - PJM to SERC East
    - SERC East to PJM
    - PJM to Non-PJM VACAR
    - Non-PJM VACAR to PJM
    - PJM to CENTRAL
    - CENTRAL to PJM
    - MISO to SERC East
    - SERC East to MISO
    - MISO to Non-PJM-VACAR
    - Non-PJM-VACAR to MISO
    - MISO to CENTRAL
    - CENTRAL to MISO

3. Determine voltage limits on the PJM Western, Central, and Eastern interfaces for Eastern RFC to PJM and Non-PJM-VACAR to PJM transfers.

4. Calculate voltage limits on the Bedington-Black Oak and AP South interfaces for the following transfers:

    - MISO to PJM
    - MISO to SERC East
    - MISO to Non-PJM-VACAR
    - MISO to CENTRAL
    - SERC East to PJM
    - Non-PJM-VACAR to PJM
    - CENTRAL to PJM

5. Determine First Contingency Total Transfer Capabilities (FCTTCs) for regional and sub-regional transfers following the NERC FCTTC definition.

6. Create the following polygons of limits:
    - MISO to SERC East versus MISO to PJM

- MISO to Non-PJM VACAR versus MISO to PJM
- MISO to CENTRAL versus MISO to PJM
- MISO to Non-PJM VACAR versus MISO to CENTRAL

7. Using the MUST program, perform simultaneous transfer analysis to determine the impact that various NON-SER interregional transfers may have on SER transfer limits such as:

Test Transfer	***Parallel Transfer 5000 MW**
MISO<=>PJM	MISO<=>SOUTHERN CO
	PJM<=>SOUTHERN CO
MISO<=>SERC East	MISO<=>SOUTHERN CO
	PJM<=>SOUTHERN CO
PJM<=>SERC East	MISO<=>SOUTHERN CO
	PJM<=>SOUTHERN CO

Scale Load/Generation as appropriate to model transfer between NON-SER regions.

8. Perform sensitivity analysis by using MUST to determine FCITCs for imports into PJM West, PJM-Mid Atlantic, and PJM South from both SERC East and MISO. While it is recognized that PJM is a market, this simulates emergency imports into sub-areas of PJM due to generation failures. The purpose of this analysis is to flag facilities that could become limits in these emergency scenarios when no limits appear with the import disbursed throughout PJM.