DEVELOPMENT OF A NEW PROCEDURE FOR ASSESSING POWER SYSTEM RELIABILITY IN PREPARATION FOR NERC'S STANDARDS COMPLIANCE

by

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ABSTRACT

DEVELOPMENT OF A NEW PROCEDURE FOR ASSESSING

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In response to historical reliability issues of the past and following the evolution of newly developing power system markets, NERC has created new standards for maintaining and enforcing power system reliability. Entities are still reviewing the standards and finding ways to comply with the same. Non-compliance can result in financial penalties that can add-up to $1M per day per violation.

The aim of this thesis is to propose a procedure to be followed by entities wishing to comply with NERC's reliability requirements for a preliminary determination/understanding of the current reliability situation of the system and therefore foresee any difficulties might appear in complying. As a second criterion, the thesis aimed in develops modules that use power system tools that are part of a transmission system's planner daily activity, such as: power flow analysis, contingency analysis, etc.

In lieu of validating the concept developed within this thesis, the PJM system was used as test bed.

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INTRODUCTION

1.1 Background and Definitions

The reliability of a power system is a measure of its ability to supply electric energy to all points of consumption, under acceptable standard quality, and in the amount required. Maintaining and working consistently towards improving the reliability of the bulk power system has always played a role in daily power system planning and operations. However, it has gained significant attention in the early 1960s. As early as 1962, the electricity industry created an informal, voluntary organization of operating personnel to facilitate coordination of the bulk power system in the United States and Canada. Four interconnected transmission systems were connected to three more systems, forming the largest electricity grid in the world. The year 1965 witnessed the largest blackout in history occurred until then, with as many as 30 million people losing power in the northeastern United States and southeastern Ontario, Canada. New York City and Toronto were among the affected cities, where some customers were without power for 13 hours.

1.1.1 Inception of National Electric Reliability Council (NERC)

The seeds for the inception of the National Electric Reliability Council (NERC) (as it was earlier known) were sowed as early as 1967 with the U.S. Electric Power Reliability Act, which proposed the creation of a council on bulk power coordination. Although the Act was not enacted right away, the proposed legislation stimulated the development of an industry reliability council. The National Electric Reliability Council (NERC) was established in June of 1968 in response to the 1965 blackout with nine regional reliability organizations being formalized under it. NERC was officially designated as a non-profit corporation in New Jersey in 1975. The organization was re-named as North American Electric Reliability Council (NERC) in recognition of Canada's participation.

Some of the significant historical developments associated with NERC are:

- Blackout in New York City which led to the first, limited reliability provision in federal legislation – 1977
- NERC formed a committee to address terrorism and sabotage of the electricity supply system, at the urging of the U.S. National Security Council and Department of Energy – 1987
- NERC published "NERC 2000," a four-part action plan for the future, which recommended mandatory compliance with NERC policies, criteria and guides – 1993
- Two major blackouts in the western United States prompted some Western Systems Coordinating Council (WSCC) members to enter into agreements to pay fines if they violated certain reliability standards - 1996
- Electric System Reliability Task Force established by the U.S. Department of Energy, and an independent "blue ribbon" panel formed by NERC, both determined grid reliability rules must be mandatory and enforceable in an increasingly competitive marketplace – 1997
- North America experienced its worst blackout ever, as 50 million people lost power in the northeastern and mid-western U.S. and Ontario, Canada – 2003
- U.S. Energy Policy Act of 2005 authorized the creation of a self-regulatory "electric reliability organization" that would span North America, with FERC oversight in the U.S – 2005
- NERC filed an application with FERC to become the "electric reliability organization" in the United States – 2006

- FERC certified NERC as the “electric reliability organization” for the United States – 2006
- Compliance with approved NERC Reliability Standards becomes mandatory and enforceable in the United States - 2007

Since its inception, NERC’s mission has been to improve the adequacy and reliability of the bulk power system in North America. To achieve that, NERC develops and enforces reliability standards; monitors the bulk power system; assesses future adequacy; audits owners, operators, and users for preparedness; and educates and trains industry personnel. NERC is a self-regulatory organization that relies on the diverse and collective expertise of industry participants. As the Electric Reliability Organization (ERO), NERC is subject to audit by the U.S. Federal Energy Regulatory Commission and governmental authorities in Canada.

1.1.1.1 NERC’s Reliability Definition

While there are numerous interpretations and representations of the reliability of the national grid, the North American Electric Reliability Council (NERC) has attempted to sum up reliability by the introduction of dual concepts of adequacy and security.

Adequacy is a measure of the ability to meet the aggregate power and energy requirements. It reflects the existence of sufficient generation, transmission and distribution facilities to satisfy the customer demand.

Security, on the other hand, reflects the ability to withstand disturbances.

Whereas reliability deals with the situations where the power system is not able to perform its primary functions, security accounts for the margin that separates the analyzed operating conditions from unreliability events. Security addresses various limits such as: applied voltage magnitudes, power flows, transfer capability, inter-area exchange, generation reserves, stability measures, and the available margins with respect to these limits. Reliability analyses involve evaluating various system contingencies at different load levels; analyzing their consequences to consumers, generation utilities, and transmission system; deciding whether the reliability should be enhanced; revealing the most influential factors and system components effecting reliability; and finding the most efficient ways to enhance reliability by better power system design, maintenance, planning and operational procedures.

In security and reliability studies, both the deterministic and probabilistic assessments are employed. Deterministic methods refer to the traditional planning approach in which a selected (usually limited) group of contingencies is examined to account for system problems such as branch overloads or voltage problems. In this method, all the contingencies are implicitly given a uniform probability of occurrence. Probabilistic methods usually encompass a larger set of contingencies, e.g., the ones with all combinations of one or two components taken out. These contingencies have different probability of occurrence depending on the types of components, line length, type of generating unit, voltage level, etc. Reliability is evaluated by stressing the system in many different ways and weighting the consequences of any particular situation by the probability of its occurrence. The probability of contingencies and load levels, where the unreliability events occur, play a key role in probabilistic methods along with the number and degree of violations, and the results of remedial actions used to eliminate system problems. The deterministic and probabilistic approaches compliment each other in the transmission planning routines.

1.2 NERC Reliability Assessment and Standards

NERC uses the annual reliability survey as an approach to identify and rank factors that electrical power industry executives and professionals may perceive as negatively impacting the bulk power system reliability in North America. The results of this annual survey are also utilized to develop reliability assessment metrics and outline reliability benchmarking programs. Figure 1.1 pictorially depicts the ranking of technical issues in terms of their perceived severity of impact on the national grid reliability, as per the 2007 survey.

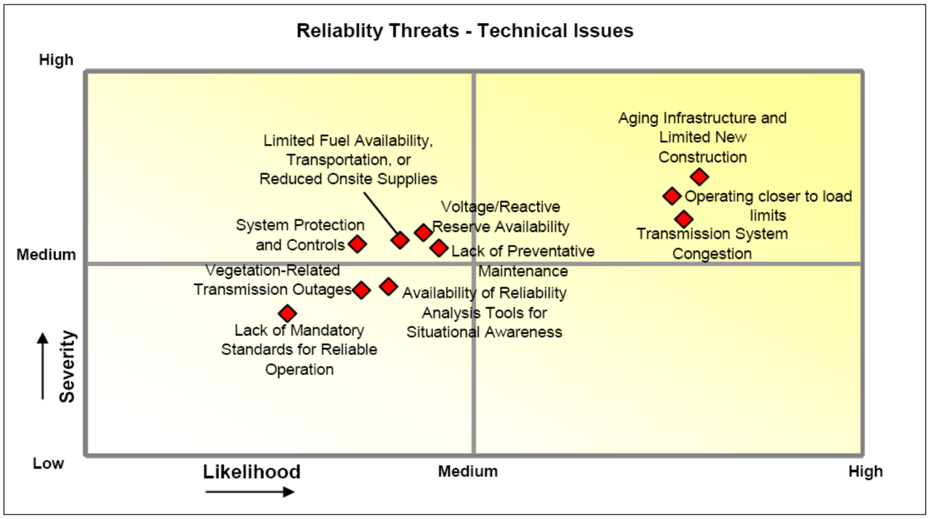

Figure 1.1 Combined Views of Technical Issue Rankings – Impact on Grid Reliability

1.2.1 NERC Standards

As mentioned earlier, the system operation is assessed under various operational conditions. NERC outlines 4 categories of operational stresses that are utilized for assessing the operational and planning reliability:

- System Performance under Normal Conditions - Category A Assessment, Standard TPL-001-0.
- System Performance following loss of a Single Bulk Electric System (BES) Element - Category B Assessment, Standard TPL-002-0.
- System Performance following loss of two or more Bulk Electric System (BES) Elements - Category C Assessment, Standard TPL-003-0.
- System Performance following extreme events resulting in loss of two or more Bulk Electric System (BES) Elements - Category D Assessment, Standard TPL-004-0.

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No [b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled [c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline [f]	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c]	No No No No

Figure 1.2 NERC Reliability Category Chart

The ensuing subsections discuss each of the abovementioned standards.

1.2.1.1 System Performance under Normal Conditions – Category A, Standard TPL-001-0.

The NERC reliability compliance requirements mandate that the planning authority and the associated transmission planner demonstrate that each entity's portion of the interconnected system is reliable enough to supply projected customer's demand and projected firm transmission services, at all demand levels over the range of forecasted demands, with all transmission facilities in service, and under normal operating conditions. Compliance further mandates that concerned entities demonstrate in their assessment that the following aspects have been taken into account:

- ❖ All critical system conditions and study years have been spanned;
- ❖ Study has been conducted annually unless system topology changes warrant additional analyses;
- ❖ All normal operating condition procedures are taken into account;
- ❖ All projected firm transfers are taken into account;
- ❖ Assessment is performed for selected demand levels, from the set of forecasted system demands;
- ❖ Existing and planned facilities are included;
- ❖ Demonstration that system performance meets criteria outlined in Figure 1.2

1.2.1.2 System Performance following loss of a Single Bulk Electric System (BES) Element - Category B, Standard TPL-002-0.

The NERC reliability compliance requirements mandate that the planning authority and the associated transmission planner demonstrate that each entity's portion of the interconnected system is reliable enough to supply projected customer's demand and projected firm transmission services at all demand levels over the range of forecasted demands, with all transmission facilities in service, and under Category B contingency conditions as outlined in Figure 1.2. Compliance further mandates that concerned entities demonstrate in their assessment that the following aspects have been taken into account:

- ❖ All critical system conditions and study years have been spanned;
- ❖ Study has been conducted annually unless system topology changes warrant additional analyses;
- ❖ All normal operating condition procedures are taken into account;
- ❖ All projected firm transfers are taken into account;
- ❖ Assessment is to be conducted over a 5-year horizon period;

- ❖ Assessment is performed for selected demand levels, from the set of forecasted system demands;
- ❖ Existing and planned facilities are included;
- ❖ Effects of existing and planned control devices are included;
- ❖ Include planned outage of any bulk electric device at demand levels for which those planned outages are performed;
- ❖ Demonstrate that system performance meets Category B contingency criteria outlined in Figure 1.2

1.2.1.3 System Performance following loss of two or more Bulk Electric System (BES) Elements - Category C, Standard TPL-003-0.

The NERC reliability compliance requirements mandate the planning authority and the associated transmission planner to demonstrate that each entity's portion of the interconnected system is reliable enough to supply projected customer's demand, and projected firm transmission services at all demand levels, over the range of forecasted demands, with all transmission facilities in service and under Category C contingency conditions as outlined in Figure 1.2. Compliance further mandates that concerned entities demonstrate in their assessment that the following aspects have been taken into account:

- ❖ All critical system conditions and study years have been spanned;
- ❖ Study has been conducted annually unless system topology changes warrant additional analyses;
- ❖ Take into account all normal operating condition procedures;
- ❖ Take into account all projected firm transfers;
- ❖ Assessment to be conducted over a 5-year horizon period and long-term (6 through 10 year) period;
- ❖ Assessment performed for selected demand levels from the set of forecasted system demands;
- ❖ Include existing and planned facilities;

- Include effects of existing and planned control devices;
- Include planned outage of any bulk electric device at demand levels for which those planned outages are performed;
- Include Reactive power resources to ensure adequate reactive power to meet system requirements;
- Demonstrate that system performance meets Category C contingency criteria outlined in Figure 1.2

1.2.1.4 System Performance following extreme events resulting in loss of two or more Bulk Electric System (BES) Elements - Category D, Standard TPL-004-0.

The NERC reliability compliance requirements mandate the planning authority and the associated transmission planner to demonstrate that each entity's portion of the interconnected system is reliable enough to supply projected customer's demand, and projected firm transmission services at all demand levels, over the range of forecasted demands, with all transmission facilities in service, and under Category D contingency conditions as outlined in Figure 1.2. Compliance further mandates that concerned entities demonstrate in their assessment that the following aspects have been taken into account:

- All critical system conditions and study years have been spanned;
- Study has been conducted annually unless system topology changes warrant additional analyses;
- Take into account all normal operating condition procedures;
- Take into account all projected firm transfers;
- Assessment to be conducted over a 5-year horizon period and long-term (6 through 10 year) period;
- Assessment performed for selected demand levels from the set of forecasted system demands;
- Include existing and planned facilities;
- Include effects of existing and planned control devices;

- ❖ Include planned outage of any bulk electric device at demand levels for which those planned outages are performed;
- ❖ Include Reactive power resources to ensure adequate reactive power to meet system requirements;
- ❖ Demonstrate that system performance meets Category D contingency criteria outlined in Figure 1.2

1.2.2 NERC Compliance

As mentioned in the previous subsection, NERC has developed a set of reliability standards designed to maintain and promote reliability in the US and Canada. Owners, operators and users of the bulk power system are required to comply with those standards. In order to enforce compliance, NERC and regional entities following a specific guideline can make use of non-monetary sanctions and monetary penalties.

There are two methods of audit: schedule and non-schedule audits. For the scheduled audit, the notice is given 2 months in advance to the registered entity. The unscheduled audit can take place with only 10 days of previous notice. The whole compliance auditing process timeline is depicted in figures 1.3, 1.4, and 1.5.

CMEP timelines dated 10/16/2007, as accepted by FERC Order issued March 21, 2008

	Action	Timeline	Page	Category
COMPLIANCE MONITORING PROCESSES	**Compliance Audits, CMEP Sections 3.1-3.1.6**			
	Compliance Enforcement Authority (CEA) notifies Registered Entity (RE) of regularly scheduled audit	2 months advance notice, at least, prior to commencement of audit	7	Compliance Audit
	Compliance auditor team leader sends all necessary pre-audit paperwork to RE	2 months advance notice, at least, prior to commencement of audit	7	Compliance Audit
	CEA shall notify RE of **unscheduled** audit	10 business days advance notice, at least	10	Compliance Audit
	The compliance audit process normally completes within 60 days of the onsite compliance audit work at the RE's site	60 days to complete process	7	Compliance Audit
	RE may object to members of audit team of **unscheduled** audit	5 business days, at least, prior to start of audit	10	Compliance Audit
	RE is notified of revisions to schedule audit dates by Regional Entity	60 days in advance	10	Audit Schedule
	RE must provide in writing their objection to audit team members	15 business days - no later than, prior to audit	11	Compliance Audit
	If audit team member is assigned less than 20 days before beginning of onsite audit, RE provide objection to CEA within 5 business days of assignment of audit team member	5 business days, within, prior to start of audit	11	Compliance Audit
	RE receives final audit report	5 business days, at least, prior to public release	12	Compliance Audit
	Self-Certification, CMEP Sections 3.2 - 3.2.1			
	CEA requests RE to make self-certification, if standard does not specify advance notice period this request will be issued in a timely manner	30 days advance notice, normally	12	Self-Certification
	CEA completes assessment of RE's self-certification	60 days of CEA's receipt of date - if no alleged violations are found	12	Self-Certification
	Spot Checking, CMEP Sections 3.3 - 3.3.1			
	CEA will allow at least 20 days for RE to submit data for review	20 days, at least, for data to be submitted	15	Spot checking
	CEA completes spot checking process	90 days of CEA's receipt of data - if no alleged violations	15	Spot checking
	Compliance Violation Investigations, CMEP Sections 3.4 - 3.4.1			
	Regional Entity notifies RE and NERC of decision to initiate Compliance Violation Investigation (CVI) and reasons for it	2 business days after decision to initiate CVI	18	Compliance Violation Investigation
	CEA completes Compliance Violation Investigation (CVI)	60 days- normally, if no alleged violations following decision to initiate CVI	18	Compliance Violation Investigation
	NERC notifies FERC and Applicable Government Authority (AGA) of CVI	2 business days after NERC is notified of decision to initiation CVI	19	Compliance Violation Investigation
	CEA requests data or documentation from RE for CVI	20 days advance notice - no less than	19	Compliance Violation Investigation
	RE may object to member of CVI team	10 business days, within receiving notification of CVI	19	Compliance Violation Investigation
	Self-Reporting, CMEP Section 3.5			
	CEA completes self-reporting process	60 days, normally within, from CEA's receipt of data	22	Self-Reporting
	Periodic Data Submittals, CMEP Sections 3.6 - 3.6.1			
	CEA requests data submittal from RE, if standard does not specify an advance notice period	20 days, no less than	24	Periodic Data Submittals
	CEA completes periodic data submittal process	10 business days, generally within, if no violations are found	24	Periodic Data Submittals
	Complaint Process, CMEP Sections 3.8 - 3.8.1			
	CEA completes the complaint process	60 days, normally within, following receipt of complaint, if no violations are found	26	Complaint Process

Figure 1.3 NERC Compliance Timeline – Monitoring Processes

CMEP timelines dated 10/16/2007, as accepted by FERC Order issued March 21, 2008

	Action	Timeline	Page	Category
ENFORCEMENT	**Notification of Alleged Violation, CMEP Sections 5.1 - 5.5**			
	RE shall elect a determination of violation	30 days, within receipt of notice of alleged violation	30	Notification of Alleged Violation
	NERC forwards copy of alleged violation to FERC & AGA	2 business days, within, of receipt of notice of alleged violation from CEA	31	Notification of Alleged Violation
	RE does not contest or respond to notice of alleged violation, it shall be deemed to have accepted the violation	30 days, within receipt of notice of alleged violation	31	Notification of Alleged Violation
	CEA schedules conference with RE if RE contests alleged violation	10 business days, within, after receipt of RE's response	31	Notification of Alleged Violation
	RE may request a hearing if CEA and RE are unable to resolve all issues of alleged violation	40 days, within, after RE's response	31	Notification of Alleged Violation
	RE may appeal hearing body's decision to NERC via NERC's appeal process	90 days, generally completes within, of NERC's receipt of request	32	NERC appeal process
MITIGATION	**Mitigation of Violations of Reliability Standards, CMEP Sections 6.0 - 6.7**			
	RE's request for extension of mitigation plan	5 business days, at least, before original milestone or completion date, must be received by CEA	38	Mitigation plans
	CEA notifies NERC of extended mitigation plan	5 business days, within, after determining extension is justified	38	Mitigation plans
	RE submits mitigation plan to CEA	30 days after being served with alleged violation, within, if RE does not protest	38	Mitigation plans
	If RE disputes alleged violation, RE submits mitigation plan following issuance of written decision of hearing body, unless RE elects to appeal the hearing body's determination to NERC	10 business days, within, of issuance of written decision of hearing body	38	Mitigation plans
	CEA will complete its review of mitigation plan and issue a statement accepting or rejecting it, unless the review period is extended by the CEA	30 days, within, of receipt of mitigation plan	39	Mitigation plans
	CEA will notify RE if accepting or rejecting revised mitigation plan	10 business days, within, receipt of revised mitigation plan	39	Mitigation plans
	Regional entities will notify NERC of acceptance of mitigation plan	5 business days, within, of acceptance of mitigation plan	39	Mitigation plans
	Regional Entity will provide NERC with accepted mitigation plan	5 business days, within, of acceptance of mitigation plan	39	Mitigation plans
	NERC will submit to FERC, as non-public information, an approved mitigation plan related to violations of the reliability standards	7 business days, within, after NERC approves mitigation plan	39	Mitigation plans
REMEDIAL ACTION DIRECTIVES	**Remedial Action Directives, CMEP Sections 7.0**			
	Regional Entity will notify NERC after issuing a Remedial Action Directive	2 business days, within, after issuing Remedial Action Directive	41	Remedial Action Directives
	RE may contest Remedial Action Directive with written notice to CEA	2 business days, within, following the receipt of Remedial Action Directive	41	Remedial Action Directives
REPORTING AND DISCLOSURE	**Reporting and Disclosure, CMEP Section 8.0**			
	Regional Entities shall report any alleged violations to NERC	5 business days, within, after Regional Entity has received any allegations or evidence of violations	43	Reporting and disclosure
	Regional Entity shall notify NERC if violation has resulted, or may potentially result, in a loss of reliability	48 hours, within, after Regional Entity's receipt of any allegations or evidence	43	Reporting and disclosure
	NERC shall notify FERC or AGA of receiving notice from Regional Entity for situation listed above	2 business days, within, after receiving report from Regional Entity of any allegations or violations	43	Reporting and disclosure
	Regional Entities shall notify NERC of all confirmed violations, including penalties, sanctions, mitigation plans, schedules, and settlements	10 business days, within, after the determination of each	43	Reporting and disclosure
	Regional Entities will provide a report of confirmed violation to the affected RE	10 business days, within, after the determination of each	43	Reporting and disclosure
	NERC will publicly post each report of confirmed violation	5 business days, no sooner than 5 business days after report is provided by Regional Entity to NERC and RE	43	Reporting and disclosure
NON-SUBMITTAL OF REQUESTED DATA	**Process for Non-Submittal of Requested Data, CMEP Attachment 1**			
	If data required by CEA is not received , a reliability standard violation may be applied at the Severe Violation Severity Level	30 days after the Required Date	Attach 1	Non-submittal of requested data

Figure 1.4 NERC Compliance Timeline – Enforcement, Mitigation, etc

CMEP timelines dated 10/16/2007, as accepted by FERC Order issued March 21, 2008				
	Action	Timeline	Page	Category
NERC'S RULES OF PROCEDURE	Rules of Procedure, Section 400 - Compliance Enforcement, Mar. 21, 2008			
	NERC shall provide a written response and plan to the board after an independent audit of NERC's CMEP program, if audit report includes recommendations	30 days, within, of release of final audit report	34	Independent audit of NERC's CMEP
	Regional Entity will report to NERC within 48 hours violations of requirements of standards for which noncompliance may cause bulk power system reliability to diminish	48 hours, within, after Regional Entity learns of violation	35	48 hours
REVIEW OF NERC DECISIONS	Review of NERC Decisions, ROP Section 409			
	Either the RE or Regional Entity challenging a non-compliance finding shall file a notice of challenge with NERC's Director of Compliance	21 days, no later than, after issuance of notice of finding of violation or audit finding	37	Review of NERC Decisions
	NERC's Director of Compliance may file with the hearing body a response to issues raised in the notice of challenge	21 days, within, after receiving a copy of the notice of challenge	37	Review of NERC Decisions
	Regional Entity or RE may appeal the decision of the CCC by filing a notice of appeal with NERC's Director of Compliance	21 days, no later than, after issuance of written decision by CCC	37	Review of NERC Decisions
	NERC CMEP staff may file its response to issues raised in the notice of appeal	21 days, within, after receiving a copy of notice of appeal	37	Review of NERC Decisions
	Entity that is filing appeal may file a reply within 7 days	7 days, within, after receipt of NERC's CMEP staff's response	38	Review of NERC Decisions
APPEALS FROM FINAL DECISIONS OF REGIONAL ENTITIES	Appeals from Final Decisions of Regional Entities, ROP Section 410			
	RE's wishing to file appeal for final decision of Regional Entity regarding non-compliance, shall file its appeal with NERC's Director of Compliance	21 days, no later than 21 days after issuance of final decision from hearing body	38	Appeals from Final Decisions of Regional Entities
	Regional Entity shall file entire record of notice of appeal with NERC's Director of Compliance	21 days, within, after receiving a copy of the notice of appeal	38	Appeals from Final Decisions of Regional Entities
	Entity filing the appeal may file a reply to Regional Entity	7 days, within, after receiving response from Regional Entity	38	Appeals from Final Decisions of Regional Entities

Figure 1.5 NERC Compliance Timeline – Decision, Appeals, etc

The ensuing subsections discuss the penalties and sanctions at NERC's disposal to enforce compliance.

1.2.2.1 Non-monetary Sanctions

The imposition of sanctions doesn't necessarily need to be monetary. The non-monetary sanctions may include, but are not limited to the following:

- Limitation on activities, functions, or operations
- Placing an entity on a reliability watch list composed of major violators

1.2.2.2 Monetary Penalties

Monetary penalties are assigned based on two factors: Violation Risk Factor (VRF) and Violation Severity Factor (VSF). These factors were assigned to each reliability standard and range from low, medium, and high for VRF and lower, moderate, high, and severe for VSFs. They determine the "Base" penalty amount. Figure 1.6 depicts a chart with the "Base" penalty amount associated with each VRF and VSF. Other factors such as recurrence of violation, self disclosure, or intentional violation are also provisioned in the guidelines and will be taken into account when setting the final penalty amount. On the process of adjusting the final penalty amount, NERC/regional entity will take into consideration the violator's ability to pay the penalty as well.

	Violation Severity Level							
Violation Risk Factor	Lower		Moderate		High		Severe	
	Range Limits		Range Limits		Range Limits		Range Limits	
	Low	High	Low	High	Low	High	Low	High
Lower	$1,000	$3,000	$2,000	$7,500	$3,000	$15,000	$5,000	$25,000
Medium	$2,000	$30,000	$4,000	$100,000	$6,000	$200,000	$10,000	$335,000
High	$4,000	$125,000	$8,000	$300,000	$12,000	$625,000	$20,000	$1,000,000

Figure 1.6 NERC Base Penalty Amount Chart

In the United States, the Federal Power Act allows for the imposition of civil penalties of up to $1,000,000 per day per violation. Therefore, NERC is observing this Federal Act as a cap or maximum allowed penalty amount per violation per day.

In such a scenario, complying with NERC's reliability policies and standards becomes extremely significant for various utilities and market participants alike. Apart from operational restrictions, the financial viability and/or functioning of a utility or market participant stands to be jeopardized in case of any such violation. The primary objective of the research documented in this thesis is to assist and equip utilities and/or market participants with a tool to assess violations associated with some of the NERC reliability standards that they may be held responsible for. It is important to bear in mind the fact that the planning and/or operational reliability assessment tool developed in this thesis would be associated with reliability compliance for the restricted standards discussed above. Furthermore, the approach for reliability assessment documented in this thesis is restricted to deterministic assessment utilizing the traditional planning approach. Apart from lending themselves to overall system reliability assessment, the planning and operational reliability assessment approaches documented in this thesis are aimed at assisting various entities in the deregulated energy market in assessing the NERC reliability compliance from their individual perspectives. Figure 1.7 depicts the impact matrix associated with the reliability assessment approach documented

	Planning Reliability Assessment	Operational Reliability Assessment	Security Assessment
Federal Agencies	✓	✓	✓
State PUCs	✓	✓	✓
ISOs / RTOs / NERC Regions / EPRI	✓	✓	✓
Utility Companies	✓	✓	✓
Power Marketers	✓		
Large Industrial Customers	✓	✓	✓
Consulting Companies	✓	✓	✓
Cities	✓	✓	✓
Counties	✓	✓	✓
Municipalities	✓	✓	

in this thesis, with respect to the entities that can utilize the same for compliance purposes.

Figure 1.7 Assessment Modules and Benefiting Entities

1.3 PJM: Test System Overview

The Pennsylvania New Jersey Maryland Interconnection ("PJM") system was used as a test bed to demonstrate the concept validation of the various reliability assessment approaches adopted, developed, and discussed in this thesis. Apart from being the pioneer of modern-day energy markets in the U.S, the PJM interconnection provides a comprehensive and well-organized database of information associated with its planning operations. The details associated with various planning and operational aspects of the PJM interconnection are made available on their publicly accessible website.

PJM oversees the world's largest wholesale electricity market and operates the world's largest centrally dispatched grid. PJM ensures electric reliability to 51 million customers with its footprint spanning all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. Figure 1.8 depicts a geographical map of the PJM region, identifying its member utilities.

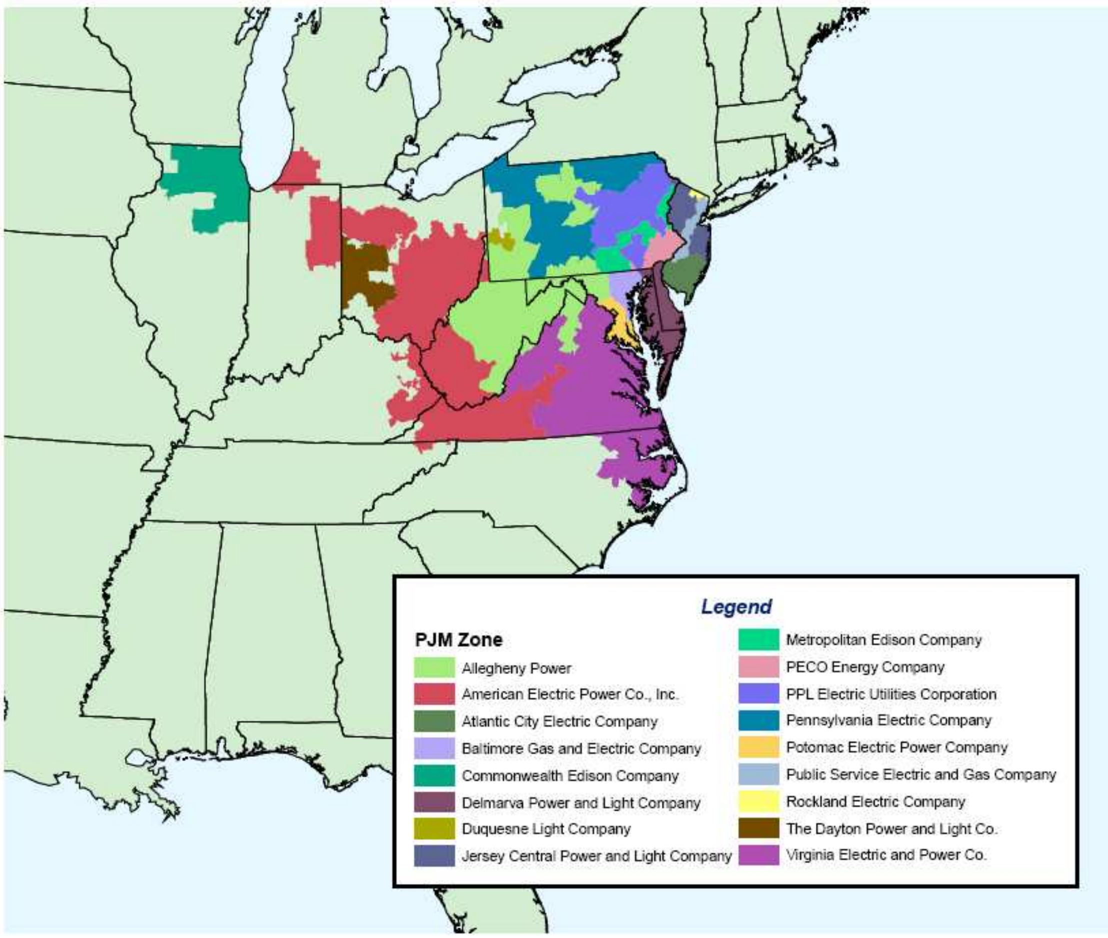

Figure 1.8 PJM Geographical Map with Control Areas

PJM does not own generation or transmission assets, nor does it take ownership of the energy flowing on the system. PJM currently comprises of more than 450 members, with approximately 1271 generating stations deriving their power from diverse energy/ sources/ fuel types. Table 1.1 provides a basic factual overview associated with the size of PJM in terms of generation capacity & stations, demand, transmission circuit, and the area/consumers served.

Table 1.1: PJM Fact-file

PJM Fact-file	
Generating Stations	1271
Generation	164,905 MW
Peak Load	144,644 MW
Length of transmission lines	56,250 Miles
Substations	6038
Area served	164,260 sq. mi
Membership	450+
Electricity users	51 million

PJM is responsible for maintaining the integrity of the regional power grid and for managing changes and/or additions to the grid to accommodate new generating plants, substations and transmission lines. PJM analyzes and forecasts the future electricity needs of the region. It also ensures that the growth of the electric system takes place efficiently, in an orderly, planned fashion, and that reliability is maintained.

PJM will be required to meet the standards as it accumulates the following functions:

- Balancing Authority (BA): Integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.
- Planning Coordinator (PC): Ensures a plan (generally one year and beyond) is available for adequate resources and transmission within a Planning Coordinator Area. It integrates and evaluates the plans from the Transmission

Planners and Resource Planners within the Planning Coordinator Area to ensure those plans meet the Reliability Standards.

- Reliability Coordinator (RC): Ensures the real-time operating reliability of the bulk power system within a Reliability Coordinator Area.
- Resource Planner (RP): Develops a plan (generally one year and beyond) within its portion of a Planning Coordinator Area for the resource adequacy of its specific loads (End-use Customer demand and energy requirements) within a reliability area.
- Transmission Operator (TOP): Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
- Transmission Planner (TP): Develops a plan (generally one year and beyond) for the reliability of the interconnected bulk power system within the Transmission Planner Area. Ensures that the plan integrates resources and transmission within its area, as well as coordinating with the plans from adjacent, and overlapping Transmission Planners, and Resource Planners. The Transmission Planner also ensures that the plan meets the Reliability Standards.
- Transmission Service Provider (TSP): Administers the transmission tariff and provides transmission services under applicable transmission service agreements (for example, the pro forma tariff).

1.4 Thesis Objective/Motivation

The NERC reliability standards as discussed in the previous sections, was recently created and enforced. All entities required to comply with those standards are still trying to develop procedures, according to their interpretation, to analyze their system for fulfilness of the compliance criteria's.

The objective of this thesis is to provide a procedure for entities to follow in order to help them in assessing their system's reliability. In doing so, the focus of the thesis is to develop a procedure that uses tools that are readily available to transmission system planners. Furthermore, to provide a more in-depth look into the system's reliability, the assessment of the same was broken down into three different parts namely: planning assessment module, operational assessment module and security assessment module. Each of these procedures would give the entity using it a good inside look of the most important aspects of the system's reliability separately. However, using these three aspects together would provide a good basis for a preliminary assessment of how the entity is or is not complying with the reliability standards.

The following chapters will discuss the three procedures in further detail.

CHAPTER 2

OPERATIONAL ASSESSMENT MODULE

The operational reliability assessment primarily pertains to assessing the stress on the transmission system associated with various operational scenarios. The transmission congestion evaluation associated with reliability assessment differs from its economic impact in that it needs to be analyzed under a host of deterministic as well as probabilistic operational scenarios, as outlined by NERC in its reliability compliance guidelines. Lately, a lot of importance has been given to the economic implications associated with transmission congestion, including the cost associated with more expensive generation, which is required to offset the cheaper generation in order to alleviate congestion. However, the reliability concerns associated with transmission congestion have far more long-reaching consequences if not given due attention during operational and planning stages.

In this module, the aim is to design a transmission congestion based operational reliability assessment tool to account for various deterministic and probabilistic scenarios taken into account when assessing operational reliability. The operational reliability assessment module is modeled to include either one or more combinations of the category assessments described in Chapter 1. The application of the module to assess transmission congestion in the wake of the all the preceding discussions is demonstrated using the example of PJM system as for all other modules in this thesis. The ensuing discussion focuses on describing in ample detail the process methodology, case studies, and results associated with the operational reliability assessment.

2.1 Process Methodology

Figure 2.1 depicts the flowchart outlining the process methodology associated with the operational reliability assessment tool. As it is evident from Figure 2.1, hourly data associated with the demand, generation resource-specific dispatch and economic data, and firm power transfers are loaded into the FERC 715 transmission topology in PowerWorld Simulator, utilizing an automated Visual Basic driven algorithm. The user has the flexibility of choosing the nature of the operational conditions under which the transmission congestion analysis would be carried out. Provisions have been made to accommodate various transmission topology changes such as the inclusion of outages in unison with the choice made by the user. The menu driven user's menu associated with the operational conditions govern the set of contingencies under which the transmission congestion study shall be executed. All relevant transmission elements/ flow-gates/ tie-lines within the PJM system are monitored for each hour of execution associated with the transmission congestion analysis.

For each hour of the analysis, all the transmission elements serving as constraints (associated with the chosen set of operational conditions) are extracted and tabulated in an external cumulative database that keeps track of the number of occurrences associated with previously existing over-loads and the addition of a new transmission constraint to the database. The process is repeated for the specified duration of the transmission congestion study.

The outcome of the study will be a table with elements which have experienced congestion, the cumulative number of hours each particular element got overloaded, and the kV level of each element. The table will be sorted in descending order according to kV level, followed by the number of hours. Therefore, the elements will be ranked from top to bottom in order of higher to lower reliability concern.

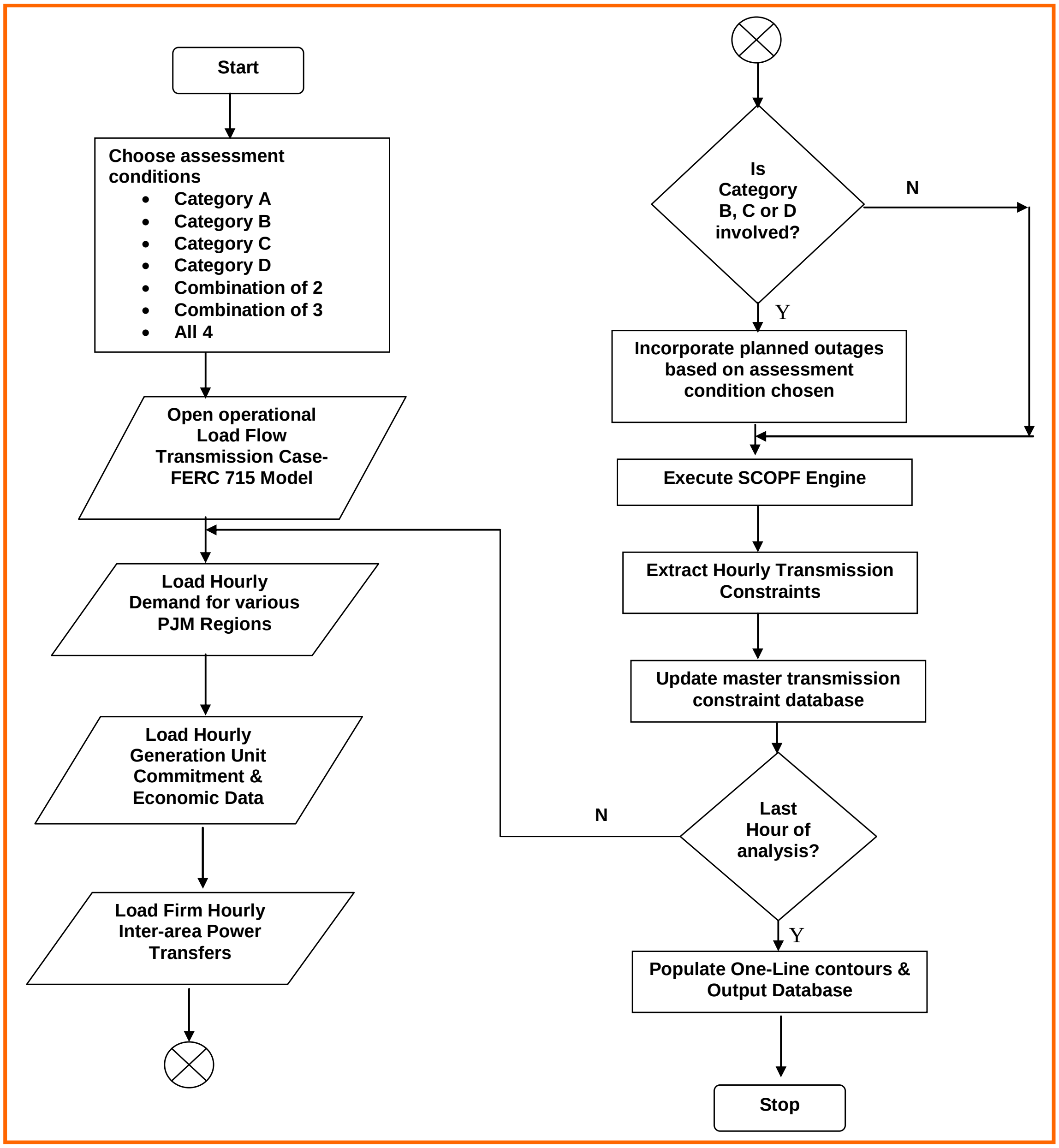

Figure 2.1 Operational Reliability Assessment Module – Process Methodology Flowchart

2.2 Concept Validation: PJM Test System

One such case study was designed to demonstrate the capability of this module in performing the transmission congestion analysis and utilizing the results obtaining thereof in assessing reliability issues associated with the underlying operational conditions, if any. The case study definition is comprised of the following:

- Term of Assessment: Short-term (within 5 year period)
- Year of Assessment: 2010
- Operational Conditions: Category A/B/C Contingencies
- Demand Conditions: Summer Peak – August 2010 for PJM
- Firm Power Transfers: Hourly Transactions associated with PJM
- Transmission Topology: PJM RTEP Summer Peak 2010 Case
- Outages: List of Planned outages provided by PJM on their website incorporated on the basis of start and end date associated with the outage

Table 2.1 provides the results of the assessment module performed using the PJM system as described above. The table contains the contingency causing the constraint, the contrained element, the number of hours in august of 2010 it was constrained, the kV level for the constrained element, and the thermal rating. The table is sorted according to kV level in descending order first, and then by number of hours constrained, in descending order as well. The names and numbers of assets and buses were replaced by fictitious names and numbers to maintain confidentiality and security of PJM infrastructure.

Table 2.1: Congestion Elements Ranked according to Operational Assessment Procedure

Contingency ID	Constraint ID	Limit (MVA)	kV Level	Overloaded Hrs
PJM92	"Bus1 (1) -> Bus2 (2) CKT 1 at Bus1"	123	69	407
3ME	"Bus3 (3) -> Bus4 (4) CKT 4 at Bus3"	249	230/69	382
PS52	"Bus5 (5) -> Bus6 (6) CKT 1 at Bus5"	308	138	345
MTSTORM-MEADOWBROOK	Bus6 (6) -> Bus7 (7) CKT 1 at Bus6"	2598	500	340
L_00505SHELOCTA-00521KEYSTONEC1	"Bus8 (8) -> Bus9 (9) CKT 1 at Bus8"	90	115/138	308
L_00004CNASTONE-00026HUNTERTNC1	"Bus10 (10) -> Bus11 (11) CKT 2 at Bus10"	370	230/115	232
AP4	"Bus12 (12) -> Bus13 (13) CKT 1 at Bus12"	193	138	215
AEP_TOWER5	"Bus14 (14) -> Bus15 (15) CKT 1 at Bus14"	244	138	191
AEP_TOWER63	"Bus16 (16) -> Bus17 (17) CKT 1 at Bus16"	824	345	176
brighton-doubs-constone 500	"Bus18 (18) -> Bus19 (19) CKT 1 at Bus18"	659	230	173
L_2010301BLACKO-2010801HATFLDC1	"Bus20 (20) -> Bus21 (21) CKT 3 at Bus20"	437	138/500	153
AE4A	"Bus22 (22) -> Bus23 (23) CKT 1 at Bus22"	133	69	146
20PPL	"Bus24 (24) -> Bus25 (25) CKT 1 at Bus24"	150	115	125
AEP376	"Bus26 (26) -> Bus27 (27) CKT 4 at Bus26"	1920	765/500	91
L_00382E.TWANDA-00414N.MESHPNC1	"Bus28 (28) -> Bus29 (29) CKT 1 at Bus28"	159	115	91
2039&2040	"Bus30 (30) -> Bus31 (31) CKT 1 at Bus30"	176	115	90
JC44	"Bus32 (32) -> Bus33 (Bus33) CKT 1 at Bus32"	125	115	80
PN19	"Bus34 (34) -> Bus35 (35) CKT 1 at Bus34"	92	230/46	64
227&274	"Bus26 (26) -> Bus36 (36) CKT 1 at Bus26"	2119	500	64

Table 2.1: Continued

Contingency ID	Constraint ID	Limit (MVA)	kV Level	Overloaded Hrs
PJM92	"Bus37 (37) -> Bus38 (38) CKT 1 at Bus37"	107	69	63
L_2010301BLACKO-2010801HATFLDC1	"Bus39 (39) -> Bus40 (40) CKT 1 at Bus39"	201	138	60
PL57	"Bus41 (41) -> Bus42 (42) CKT 1 at Bus41"	504	230	60
L_05019ROSLD5-7-05072LAURELTC1	"Bus43 (43) -> Bus44 (44) CKT 2 at Bus43"	309	138	59
PN20	"Bus45 (45) -> Bus46 (46) CKT 1 at Bus45"	129	115	53
2039&2040	"Bus47 (47) -> Bus48 (48) CKT 1 at Bus47"	179	115/230	51
2PN	"Bus49 (49) -> Bus50 (50) CKT 1 at Bus49"	179	115	49
L_2010301BLACKO-2010801HATFLDC1	"Bus51 (51) -> Bus39 (39) CKT 1 at Bus51"	202	138	46
2PN	"Bus52 (52) -> Bus49 (49) CKT 1 at Bus52"	179	115	45
L_04357CHICHST2-04558LINWOODC1	"Bus53 (53) -> Bus54 (54) CKT 2 at Bus53"	904	230	44
T_00011KEYSTONE-00521KEYSTONEC3	"Bus55 (551) -> Bus56 (56) CKT 4 at Bus55"	465	230/500	43
36PS	"Bus57 (57) -> Bus58 (58) CKT 1 at Bus57"	873	230	42
2039&2040	"Bus59 (59) -> Bus60 (60) CKT 1 at Bus59"	177	230/115	41
L_00004CNASTONE-00026HUNTERTNC1	"Bus61 (61) -> Bus62 (62) CKT 1 at Bus62"	1179	500/230	37
22JC	"Bus63 (63) -> Bus64 (64) CKT 2 at Bus63"	135	230/34.5	36
6ME	"Bus65 (65) -> Bus66 (66) CKT 1 at Bus65"	50	69	30
PJM92	"Bus67 (67) -> Bus68 (68) CKT 1 at Bus68"	192	138	30
L_147456LOISACT-147586GORDNVLC1	"Bus69 (69) -> Bus70 (70) CKT 1 at Bus69"	370	230/500	25
214&263	"Bus71 (71) -> Bus72 (72) CKT 1 at Bus71"	89	115	25

Table 2.1: Continued

Contingency ID	Constraint ID	Limit (MVA)	kV Level	Overloaded Hrs
L_2010301BLACKO-2010801HATFLDC1	"Bus40 (40) -> Bus73 (73) CKT 1 at Bus40"	201	138	24
L_00022SUSQHANA-00023WESCOVLEC1	"Bus74 (74) -> Bus75 (75) CKT 1 at Bus74"	124	138	21
L_00382E.TWANDA-75413HILSD230C1	"Bus76 (76) -> Bus28 (28) CKT 1 at Bus76"	159	115	21
L_36274BRAID;B-36298DAVIS;BC1	"Bus77 (77) ->Bus78 (78) CKT 1 at Bus77"	480	345/138	21
214&263	"Bus79 (79) -> Bus80 (80) CKT 1 at Bus79"	588	230	19
L_2324305TORREY-2329505SCANTEC1	"Bus81 (81) -> Bus82 (82) CKT 1 at Bus81"	236	138	17
L_04251PERKIOMN-04808PERKIOM2C1	"Bus83 (83) -> Bus84 (84) CKT 1 at Bus83"	97	138/35	15
L_36309EFRA;R-36337GOODI;1RC1	"Bus85 (85) -> Bus86 (86) CKT 1 at Bus85"	480	345	15
AE4A	"Bus87 (87) -> Bus88 (88) CKT 1 at Bus87"	56	69	15
4JC	"Bus89 (89) -> Bus90 (90) CKT 1 at Bus89"	152	230/34.5	13
L_00477HOMERCT-00478QUEMAHONC1	"Bus91 (91) -> Bus92 (92) CKT 1 at Bus91"	159	115	13
20PPL	"Bus93 (93) -> Bus94 (94) CKT 1 at Bus93"	109	115	13
PJM22	"Bus95 (95) -> Bus96 (96) CKT 1 at Bus95"	3113	500	12
L_00477HOMERCT-00478QUEMAHONC1	"Bus92 (92) -> Bus97 (97) CKT 1 at Bus92"	146	115	11
L_00001100.00-00023WESCOVLEC1	"Bus98 (98) -> Bus99 (99) CKT 1 at Bus98"	269	138/69	11
L_00022SUSQHANA-00023WESCOVLEC1	"Bus100 (100) -> Bus101 (101) CKT 1 at Bus100"	124	138	11
PJM92	"Bus37 (37) -> Bus38 (38) CKT 2 at Bus37"	107	69	11
PN20	"Bus46 (46) -> Bus102 (102) CKT 1 at Bus46"	151	115	10
ME13	"Bus103 (103) -> Bus32 (32) CKT 6 at Bus32"	269	230/115	10

Table 2.1: Continued

Contingency ID	Constraint ID	Limit (MVA)	kV Level	Overloaded Hrs
502J-MTSTORM	Bus104 (104) -> Bus105 (105) CKT 1 at Bus104"	3464	500	10
JC4	"Bus106 (106) -> Bus107 (Bus107) CKT 1 at Bus106"	69	230/34.5	9
L_08107CORSON2-08216DENNISC1	"Bus108 (108) -> Bus109 (Bus109) CKT 1 at Bus108"	292	138	9
6ME	"Bus110 (110) -> Bus111 (111) CKT 1 at Bus110"	67	69	8
PN48B	"Bus112 (112) -> Bus113 (113) CKT 1 at Bus112"	39	115/46	8
26JC	"Bus114 (114) -> Bus115 (115) CKT 1 at Bus114"	102	115/34.5	8
L_2044501BEDNGT-2056101NIPETNC1	"Bus116 (116) -> Bus117 (117) CKT 1 at Bus116"	297	138	8
L_2256205J.FERR-2257205WYOMINC1	"Bus118 (118) -> Bus119 (119) CKT 1 at Bus118"	239	138	7
138-L0708__B-C	"Bus120 (120) -> Bus121 (121) CKT 1 at Bus120"	253	138	7
L_04048CHICHST1-04357CHICHST2C1	"Bus54 (54) -> Bus122 (122) CKT 5 at Bus54"	80	230/13.8	5
L_36311ELECT;4R-36349ELECT;3RC1	"Bus123 (123) -> Bus124 (124) CKT 1 at Bus123"	465	345/138	5
2039&2040	"Bus48 (48) -> Bus125 (125) CKT 1 at Bus48"	179	230/115	5
PL51	"Bus126 (126) -> Bus127 (127) CKT 1 at Bus126"	90	69	3
2PN	"Bus91 (91) -> Bus128 (128) CKT 1 at Bus91"	184	115	3
JC20	"Bus129 (129) -> Bus130 (130) CKT 1 at Bus129"	113	230/34.5	3
L_02534GRYSTNQ-02550WHIPPANYC1	"Bus131 (131) -> Bus132 (132) CKT 1 at Bus131"	224	230/34.5	2
L_2010301BLACKO-2010801HATFLDC1	"Bus73 (73) -> Bus20 (20) CKT 1 at Bus73"	201	138	2
PJM92	"Bus133 (133) -> Bus134 (134) CKT 1 at Bus133"	104	230/34.5	1
PL57	"Bus135 (135) -> Bus136 (136) CKT 1 at Bus135"	75	138/34.5	1
MTSTORM-MEADOWBROOK	"Bus105 (105) -> Bus6 (6) CKT 1 at Bus105"	2598	500	1
PN48B	"Bus137 (137) -> Bus138 (138) CKT 2 at Bus137"	47	115/46	1
L_01716HILLRD-01717PANTHERC1	"Bus3 (3) -> Bus139 (139) CKT 1 at Bus3"	55	69	1

CHAPTER 3

PLANNING ASSESSMENT MODULE

As mentioned earlier, in the discussion pertaining to the realization of various operational scenarios, the incorporation of deterministic and probabilistic operational conditions during reliability assessment for planning purposes is done by including category A/B/C/D conditions as per TPL standards. The primary objective of this tool is to allow planning/regulatory authorities to assess the impact of planned new generation and/or transmission system additions in the wake of the national grid operating closer to its safety/loading limits. As per the NERC reliability compliance guidelines, any new addition to the national grid needs to be assessed in terms of the impact that it would have on the short-term and long-term reliability of the bulk power system.

3.1 Process Methodology

Figure 3.1 depicts the process methodology flowchart associated with the planning reliability assessment tool developed in this thesis. The demonstration of the applicability of the tool has been performed on the PJM system in consistency with all other modules.

The major features associated with the tool in order to assess short-term/long-term power system reliability in the wake of any system additions are:

- Ability to study impact of any generation and/or transmission addition for the following operational conditions:
    - Category A Assessment
    - Category B Assessment
    - Category C Assessment
    - Category D Assessment
    - Combination of Above

- Ability to incorporate the impact of planned system outages when assessing short-term/long-term bulk power system reliability associated with generation and/or transmission assessment
- Ability to take into account future transmission infrastructure expansion by utilizing appropriate FERC 715 model for the transmission topology
- Ability to take into effect selected demand levels from the set of forecasted system demands in order to assess the impact of forecasted seasonal demand variations on the short-term/long-term planning reliability assessment
- Ability to execute a host of technical power system analysis such as:
    - Full AC Load Flow Analysis
- Quantifying the reliability concerns associated with the study by assessing the number of system elements operating closer to their load/safety limits in the form of 2 performance metrics:
    - Incremental Transmission System Over-loads
    - Incremental Voltage Limit violations
    - Any incremental transmission overload and/or voltage limit violations that were alleviated with a specific transmission/generation addition
- Ability to assist planning/regulatory authorities to quantitatively and qualitatively assess the positive and/or negative impacts that the planned transmission/generation seems to have on the reliability of the system (the study assumptions withstanding).

As depicted in Figure 3.1, the short-term/long-term reliability assessment module developed in this thesis aims to achieve the objective of taking into account the reliability compliance criterion outlined by NERC. Having said that, it achieves another important objective of keeping the reliability concerns expressed by electrical power system executives and professionals in perspective, by utilizing the metrics outlined in the 2007 NERC Survey of Reliability Issues at the forefront of the reliability assessment tool. The case study and the results thereof put forth by this thesis in the discussion presented in the ensuing section demonstrate the ability of the tool in a comprehensive fashion.

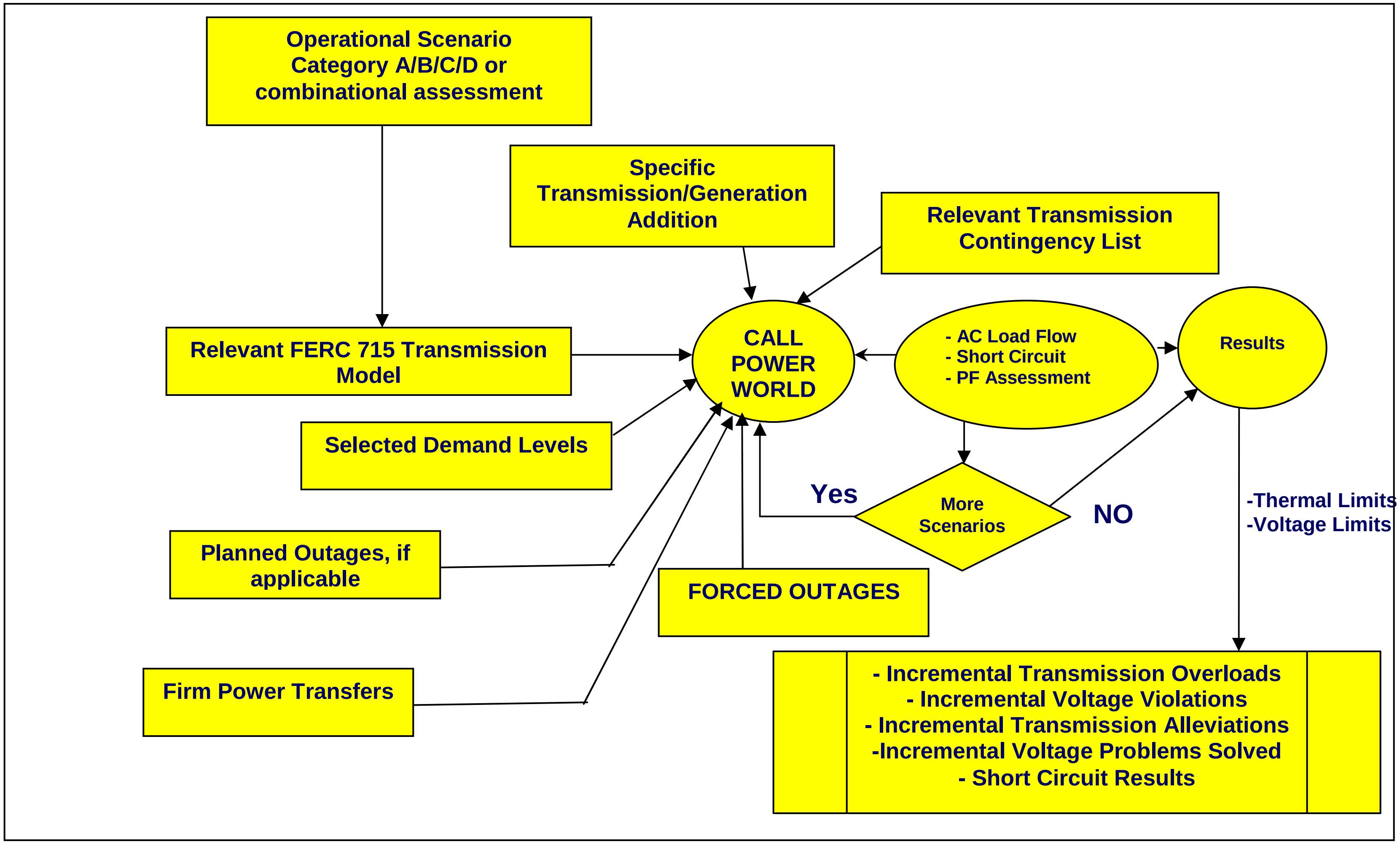

Figure 3.1 Planning Reliability Assessment Module – Process Methodology Flowchart

3.2 Concept Validation: PJM Test System

The case study utilized to demonstrate the effectiveness of the short-term/long-term planning reliability assessment module focused on the impact of incorporation of a major planned generation addition at the proposed location in the PJM system on the reliability of the bulk power system. Figures 3.2 and 3.3 depict the one-line schematic associated with the location of the generation resource with and without the 640MW generation resource. The short-term/long-term reliability assessment module was executed before and after the addition of the 640MW generation resource to assess the incremental impact that the planned resource has on the reliability of the bulk power system under the following operational conditions:

- FERC 715 Transmission Model: PJM RTEP 2011 Base Power Flow Case
- Demand Conditions: Summer Peak, 2011
- Combination of Category A/B/C/D contingency assessments
- Planned outages for Summer Peak Condition for 2011
- All transmission elements above 69kV and PJM pre-defined flow-gates monitored for thermal overload and voltage violations

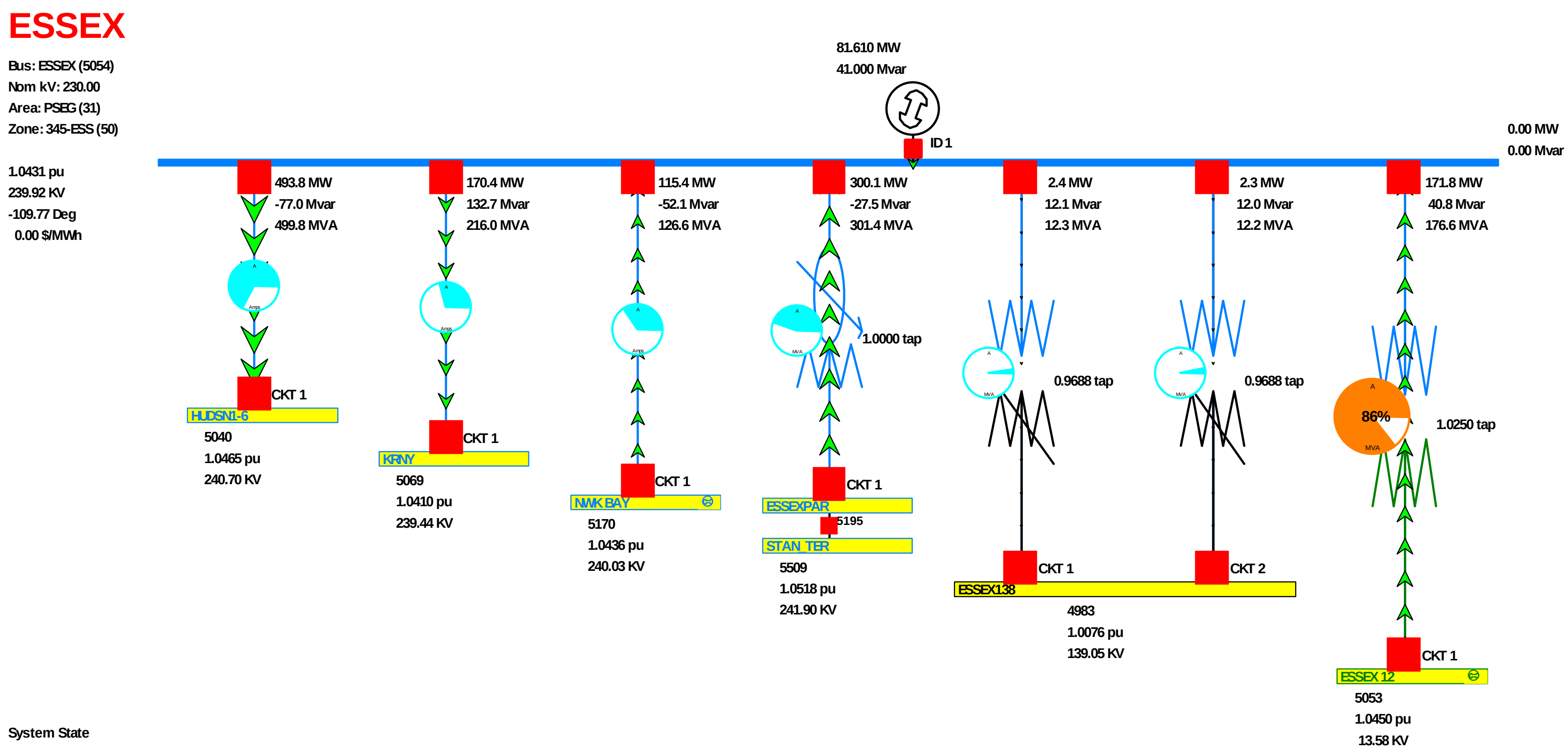

Figure 3.2 One-line schematic associated with the location of 640MW of planned generation addition – Without Resource

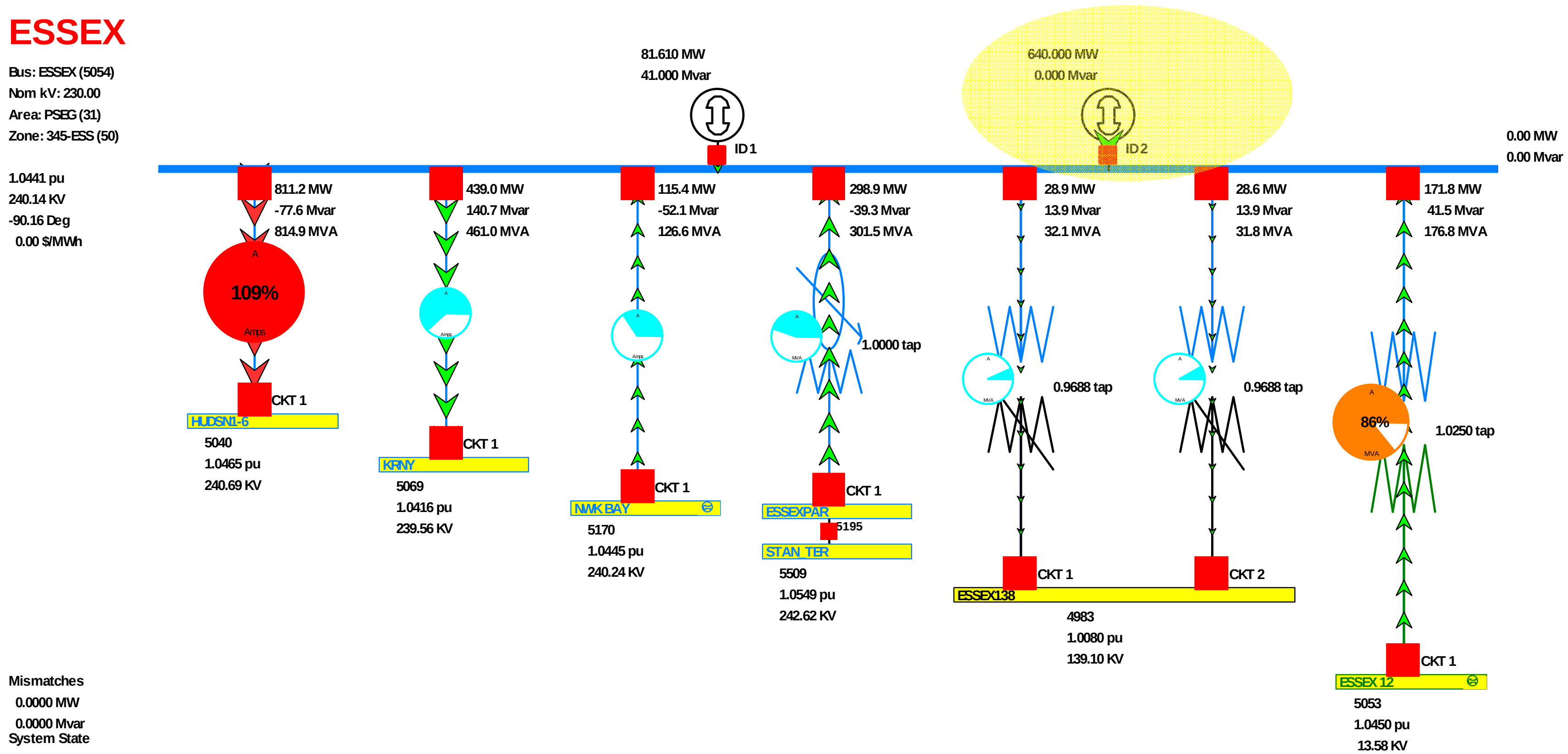

Figure 3.3 One-line schematic associated with the location of 640MW of planned generation addition – With Resource

Table 3.1: Incremental Transmission System Thermal Overload Violations – Category B/C/D Assessment

Transmission Element	Contingency		Rating B (MVA)	Incremental Violations (% Overload)
	Name	Category		
Bus1 (1) -> Bus2 (2) CKT 1 at Bus1	26PS	C	650	123.0
Bus3 (3) -> Bus4 (4) CKT 1 at Bus3	27PS	C	372	152.2
Bus5 (5) -> Bus6 (6) CKT 1 at Bus5	PS72	B	826	120.0
Bus7 (7) -> Bus8 (8) CKT 1 at Bus7	27PS	C	268	120.3
Bus9 (9) -> Bus10 (10) CKT 2 at Bus9	16JC	C	152	100.1
Bus11 (11) -> Bus12 (12) CKT 1 at Bus11	PS72	B	826	121.9
Bus13 (13) -> Bus14 (14) CKT 1 at Bus13	PS72	B	845	112.7
Bus15 (15) -> Bus16 (16) CKT 1 at Bus15	PJM67	B	1179	101.8
Bus17 (17) -> Bus18 (18) CKT 1 at Bus17	JC11	B	156	100.3
Bus19 (19) -> Bus20 (20) CKT 1 at Bus19	27PS	C	367	111.3
Bus8 (8) -> Bus21 (21) CKT 1 at Bus8	27PS	C	287	100.1
Bus22 (22) -> Bus23 (23) CKT 1 at Bus22	27PS	C	388	105.4
Bus22 (22) -> Bus24 (24) CKT 1 at Bus22	27PS	C	383	104.4
Bus25 (25) -> Bus11 (11) CKT 1 at Bus25	PS72	B	826	102.0
Bus25 (25) -> Bus26 (5040) CKT 1 at Bus25	PS20	B	826	144.2
Bus24 (24) -> Bus19 (19) CKT 1 at Bus24	27PS	C	350	131.7
Bus14 (14) -> Bus27 (27) CKT 1 at Bus14	PS72	B	752	116.7
Bus28 (28) -> Bus29 (29) CKT 1 at Bus28	BASIN TX T672	B	147	100.1

Tables 3.1 and 3.2 provide results associated with the incremental transmission system thermal over-loads associated with the addition of 640 MW of the proposed generation resource at the location indicated in Figures 3.2 under normal and contingency conditions respectively. Having said that, Table 3.4 provides a tabulated list of previously existing transmission system violations that the addition of the proposed generation resource helps alleviate. In other words, the results tabulated in Tables 3.1 through 3.4 allow the planning authority and/or transmission planner to qualitatively assess the reliability impacts associated with proposed generation.

Table 3.2 Incremental Transmission System Thermal Overload Violations – Category A (Normal Operation) Assessment

Transmission Element Information					Rating A (MVA)	Incremental Violation (% Overload)
From Number	From Name	To Number	To Name	Circuit		
1	Bus1	2	Bus2	1	395	100.2
3	Bus3	4	Bus4	1	233	104.2
5	Bus5	6	Bus6	1	375	107.3
7	Bus7	8	Bus8	1	716	114.0

Table 3.3 presents the results associated with the other metric, the incremental voltage violations, before and after the addition of the proposed generation resource at the location depicted in Figure 3.2.

Table 3.3 Incremental Voltage Violations – Category A (Normal Operation)

Bus Information		Low Voltage Limit (PU)	High Voltage Limit (PU)	Incremental Voltage Violation (PU)
Number	Name			
1	Bus1	0.95	1.05	1.06
2	Bus2	0.95	1.05	1.07
3	Bus3	0.95	1.05	1.06
4	Bus4	0.95	1.05	1.06
5	Bus5	0.95	1.05	1.06
6	Bus6	0.95	1.05	0.93
7	Bus7	0.95	1.05	0.94
8	Bus8	0.95	1.05	0.93
9	Bus9	0.95	1.05	1.07
10	Bus10	0.95	1.05	1.07
11	Bus11	0.95	1.05	1.07

The results associated with the case study utilized for the short-term/long-term planning reliability assessment module presented in Tables 3.1 through 3.4 provide great insight into the impacts that the proposed generation would have on the reliability of the bulk power system under normal or extreme operating conditions. It is known that the definition and enforcement of maintaining operational and planning reliability entails numerous aspects. However, a lot of these aspects do focus on tracking, administrative and enforcement areas which may not require a technical analytical tool such as the one developed in this thesis. Having said that, from the short-term/long-term planning reliability perspective, the tool developed in this thesis would enable numerous planning and regulatory authorities to gain valuable insight into the reliability impact of any new technology additions to the national grid.

All tables presented in this section had the names and numbers of assets and buses replaced by fictitious names and numbers to maintain the security and confidentiality of PJM's infrastructure.

Table 3.4 Incremental Transmission System Thermal Overload Alleviations – Category B/C/D Assessment

Transmission Element	Contingency		Rating B (MVA)	Releaved Violations (% Overload)
	Name	Category		
Bus1 (1) -> Bus2 (2) CKT 2 at Bus1	7ME	C	141	101.6
Bus3 (3) -> Bus4 (4) CKT 6 at Bus3	3ME	C	305	112.6
Bus5 (5) -> Bus6 (6) CKT 1 at Bus5	CED_L0102_2	B	1739	100.4
Bus7 (7) -> Bus8 (8) CKT 1 at Bus7	PE658	B	124	100.8
Bus9 (9) -> Bus10 (10) CKT 1 at Bus9	AEP7	B	4253	101.8
Bus11 (11) -> Bus12 (12) CKT 1 at Bus11	AEP_LINE_FB19	B	72	101.1
Bus13 (13) -> Bus14 (14) CKT 1 at Bus13	AEP_LINE_FB15	B	379	103.4

CHAPTER 4

SECURITY ASSESSMENT MODULE

Numerous discussions have been focused on how aspects associated with assessing bulk power system reliability and security go hand in hand with some even suggesting the latter to be a sub-set of the former. While it is understood that reliability can be interpreted as comprising of 2 major issues namely adequacy and security, the approach associated with the development of the Security Assessment Module is based more on determining elements that would pose a great threat to the reliability of the system in case they become an unforeseen outage. Security associated with bulk power systems has gained increasing importance in the wake of growing national security alert and identification of the national grid as one of the major terrorism threat targets. Clearly, the reliable operation and functioning of the national grid forms the backbone of the infrastructure for a country as vast as the United States. In view of that, the identification of critical assets associated with the bulk power system is of extreme significance.

This module aims on identifying critical assets that would support the reliable operation of the Bulk Electric System. These Critical Assets are to be identified through the application of a risk-based assessment." The primary basis utilized for the risk-assessment to identify the critical assets in a bulk power system was based on 2 metrics. The ensuing sub-sections deal with the outlining of these metrics utilized for the risk-assessment: the process methodology utilized for the development of the tool and the case study (PJM test system), and the associated results to demonstrate the same for the PJM system.

4.1 Process Methodology

As mentioned earlier, this module used 2 metrics to identify critical assets via a risk-assessment process. The primary metrics outlined and utilized by this thesis are:

1. Number of Transmission System Violations caused by the outage of a particular asset

2. In today’s national grid, which operates in a highly complex meshed-network and inter-dependent environment, it would be important to identify certain assets the unforeseen outage of which may cause serious and sometimes irreversible damage to the power system such as reliability threats in terms of transmission stress, cascading voltage issues, etc. The objective of this metric is to identify the above mentioned critical assets by quantifying the number of transmission system violations that may be caused due to the sudden outage of each of these assets in the system
3. MW Flow through associated with a particular asset

Although mostly applicable to major sub-stations across the national grid, this metric is utilized to rank the importance of the assets across the grid by quantifying the amount of power flowing through the asset at any significant instant snap-shot of time.

The module being developed for assessing security and identifying critical assets across the bulk power system employs both the aforementioned metrics in order to identify and rank assets across the system in order of merit with respect to security. The first metric i.e. number of transmission violations associated with the asset outage is utilized as the determining factor. In this case there are 2 assets that cause the same number of violations, the second metric i.e. MW flow through associated with each of those assets is utilized to rank one prior to the other. Figure 4.1 provides a process methodology flowchart signifying the methodology utilized to identify and rank critical security assets.

The Security assessment module, as designed in this thesis, provides a snap-shot assessment and identification of critical assets based on the underlying factors. In other words, the identification and ranking of critical assets obtained is dependent on the following factors:

- Transmission Topology – FERC 715 Model
- Any additional planned outage list included
- System Demand Level

- Any additional contingencies selected

Having said that, for a chosen set of parameters, the security assessment module develops a list of assets, which will automatically be converted into an outage. The tool then automatically processes each of these outages sequentially, in order to assess the number of transmission violations each of the asset outages resulted in. It goes without saying that the results are dependent on the initial state of the system. However, the flexibility in the design of the tool is reflected on the fact that the choice of the initial state of the system is provided to the user. The ensuing sub-section discusses the PJM test system and the results thereof utilized to demonstrate the tool in the PJM system.

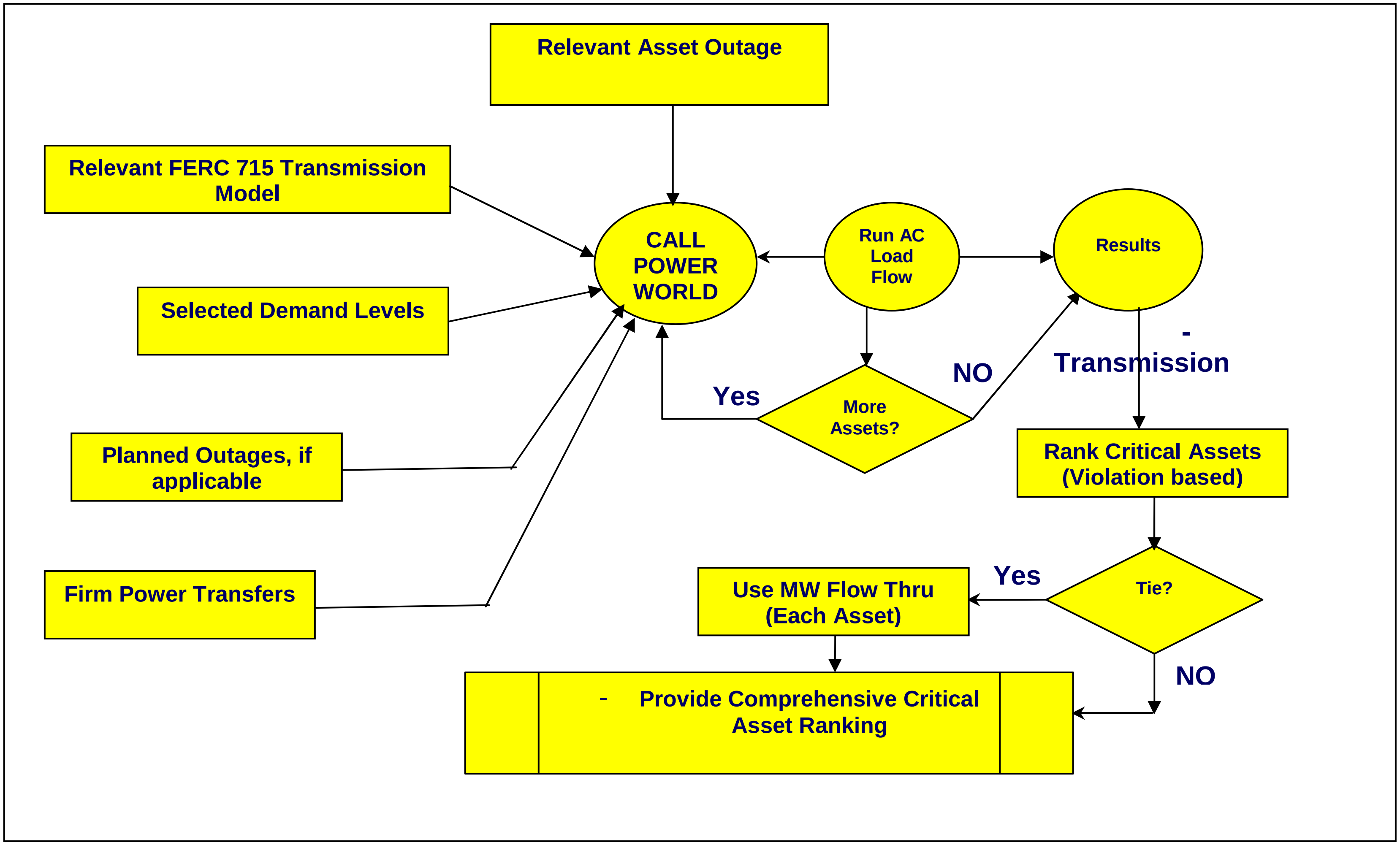

Figure 4.1 Security Assessment Module – Process Methodology Flowchart

4.2 Concept Validation: PJM Test System

As mentioned earlier, the results associated with the security assessment module will depend on the initial state of the system chosen by the user. The case study utilized for the demonstration of the tool is characterized by the following:

- FERC 715 Transmission Model: PJM RTEP 2011 Base Power Flow Case
- Demand Conditions: Summer Peak, 2011
- All transmission elements above 69kV and PJM pre-defined flow-gates monitored for thermal overload violations
- All assets with a nominal voltage rating of 69kV and above were utilized for assessment and ranking through the security assessment tool.

In other words, the PJM RTEP 2011 base transmission topology in conjunction with the summer peak demand conditions were utilized for the demonstration of the tool. Table 4.1 depicts the tabulated identification of top 40 critical assets for the given analysis condition with the rankings for each asset provided based on the metrics and methodology discussed above. The names and numbers of assets and buses were replaced by fictitious names and numbers to maintain confidentiality and security of PJM infrastructure.

Table 4.1 Results of Security Assessment Module – Identification & Ranking of Critical Security Assets, PJM 2011 Conditions

Asset Information				Number of Violations	Throughflow (MW)	Ranking
Bus Number	Bus Name	Nominal kV	Asset			
1	Bus1	138	Asset1	43	693.1	1
2	Bus2	500	Asset2	21	2016.3	2
3	Bus3	230	Asset3	20	1268.0	3
4	Bus4	230	Asset4	20	830.1	4
5	Bus5	69	Asset5	20	368.5	5
6	Bus6	230	Asset6	17	1454.3	6
7	Bus7	115	Asset7	17	1026.6	7
8	Bus8	138	Asset8	17	563.2	8
9	Bus9	230	Asset9	17	552.3	9
10	Bus10	345	Asset10	14	2296.5	10
11	Bus11	230	Asset11	13	830.1	11
12	Bus12	500	Asset12	12	1886.2	12
13	Bus13	230	Asset13	12	1610.8	13
14	Bus14	500	Asset14	12	1562.1	14
15	Bus15	230	Asset15	12	810.3	15
16	Bus16	230	Asset16	11	2431.9	16
17	Bus17	138	Asset17	11	568.8	17
18	Bus18	500	Asset18	9	2684.7	18
19	Bus19	345	Asset19	9	1261.4	19
20	Bus20	230	Asset20	9	1252.5	20
21	Bus21	230	Asset21	9	874.8	21
22	Bus22	138	Asset22	9	274.7	22
23	Bus23	230	Asset23	8	1886.2	23
24	Bus24	230	Asset24	8	1485.8	24
25	Bus25	230	Asset25	8	818.7	25
26	Bus26	138	Asset26	8	741.6	26
27	Bus27	230	Asset27	8	506.5	27
28	Bus28	69	Asset28	8	171.5	28
29	Bus29	138	Asset29	8	148.1	29
30	Bus30	69	Asset30	8	146.9	30
31	Bus31	69	Asset31	8	118.2	31
32	Bus32	69	Asset32	8	118.2	32
33	Bus33	500	Asset33	7	2775.4	33
34	Bus34	230	Asset34	7	1576.6	34
35	Bus35	115	Asset35	7	1213.2	35
36	Bus36	345	Asset36	7	1208.5	36
37	Bus37	138	Asset37	7	572.6	37
38	Bus38	230	Asset38	7	543.5	38
39	Bus39	138	Asset39	7	461.4	39
40	Bus40	230	Asset40	7	391.0	40

CHAPTER 5

CONCLUSION/FUTURE WORK

In lights of the new NERC reliability standards and the compliance enforcement (penalties that can add up to $1M per day, per violation), the thesis aims at providing a procedure for assessing system reliability that focuses in two main criteria's:

1. Using tools known to transmission planners everyday's activities;
2. Developing a systematic procedure to quantify and assess system reliability in order to help transmission planners in early stage preparation for compliance

Focusing on those two main criteria's, the thesis proposes a break down in the reliability assessment from three points: Planning Assessment, Operational Assessment and Security Assessment.

The Planning Assessment module provides a closer look into modifications/additions made to the system and qualifying the impact of such additions to the reliability of the system. For this purpose, the system is assessed both under normal and contingency conditions for thermal and voltage violations.

The Operational Assessment module focuses on quantifying the congested elements in a period through which would therefore pose a reliability threat to the system. The module provides a table with number of hours (given a period of duration) and kV level for each constrained element. It then ranks those elements starting with descending order of kV level and then descending order of number of hours constrained.

The Security Assessment module aims at ranking assets according to how critical they are to the reliability of the system. The two measures taken are how many cascading thermal violations the element would cause to the system in case it was not in-service, and the amount of Power flowing through the element.

This thesis, contributes to providing a procedural preliminary reliability assessment using regular transmission planner's tools. The research performed in this thesis provides a preliminary assessment procedure, not focusing in the individual NERC standards. Perhaps, future research could focus on getting a distinct procedure for assessing each NERC reliability standard.

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BIOGRAPHICAL INFORMATION

Frederico Von Pinho was born and raised in Rio de Janeiro, Brazil, where he graduated from high school and started his bachelor's degree in electrical engineering at the "Universidade Estadual do Rio de Janeiro (UERJ)". After 3 years of engineering school, he decided to leave everything behind and start a new venture at Wichita State University, Wichita, KS. He then moved to a community college in the same town, where he could find an on-campus job to help support himself and his wife. He completed all basic requirements there, and transferred to University of Texas at Arlington (UTA), where he was awarded two scholarships: "Outstanding Transfer Scholarship" and "Phi-Theta-Kappa". He maintained Dean's Honor Roll status from 2002 until he graduated Magna Cum Laude. After a year working at PwrSolutions, Inc. as an energy analyst, he joined UTA once again to work on his master's of science degree with emphasis in power systems.

As a part of his education, principles such as persistence, and the importance of studying and working were a constant in his life. Following such principles, he started working when he was only 13 years old as a computer technician in a computer learning center. He never stopped working from then on. His working experience goes from network administration and internet provider's management, through industrial automation, technical support, computer science instructor, etc.

While each and every past working experience has brought very valuable knowledge, the company where he has been working for the past 2 years, PwrSolutions, has contributed vastly to the development of his future career, power system's field. There, he performed many studies, i.e. Interconnection feasibility study, locational marginal pricing calculation (LMP), etc. throughout the whole U.S. and some different countries. He has now acquired knowledge about most U.S. markets (WECC, NYISO, PJM, SPP, etc), which gives him a unique position in the job market.

Frederico Von Pinho's objective is to use the knowledge gained with his master's in continuing his contribution to PwrSolutions and the energy field.