Risk-Based Dynamic Security Assessment of the Electricity Grid with High Penetration of Renewable Generation

by

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ABSTRACT

Electric power system security assessment is one of the most important requirements for operational and resource planning of the bulk power system ensuring safe operation of the power system for all credible contingencies. This deterministic approach usually provides a conservative criterion and can result in expensive bulk system expansion plans or conservative operating limits. Furthermore, with increased penetration of converter-based renewable generation in the electric grid, the dynamics of the grid are changing. In addition, the variability and intermittency associated with the renewable energy sources introduce uncertainty in the electricity grid. Since security margins have direct economic impact on the utilities; more clarity is required regarding the basis on which security decisions are made. The main objective of this work is to provide an approach for risk-based security assessment (RBSA) to define dynamic reliability standards in future electricity grids. RBSA provides a measure of the security of the power system that combines both the likelihood and the consequence of an event.

A novel approach to estimate the impact of transient stability is presented by modeling several important protection systems within the transient stability analysis. A robust operational metric to quantify the impact of transient instability event is proposed that incorporates the effort required to stabilize any transiently unstable event. The effect of converter-interfaced renewable energy injection on system reliability is investigated using RBSA. A robust RBSA diagnostics tool is developed which provides an interactive user interface where the RBSA results and contingency ranking reports can be explored and compared based on specific user inputs without executing time domain simulations or risk calculations, hence providing a fast and robust approach for handling large time domain simulation and risk assessment data. The results show that RBSA can be used effectively in system planning to select security limits. Comparison of RBSA with deterministic methods show that RBSA not only provides less conservative results, it also illustrates the bases on which such security decisions are made. RBSA helps in identifying critical aspects of system reliability that is not possible using the deterministic reliability techniques.

DEDICATION

Dedicated to my father Sumit Kanti Datta, my mother Rita Datta and my wife Aditi R Datta. Without their encouragement and selflessness none of this could have been achieved.

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GLOSSARY

A	variable that denotes the type of fault. Three-phase to ground fault, two-phase to ground fault, phase-to-phase fault and one- phase to ground fault are represented by the indices 1, 2, 3 and 4 respectively
BES	bulk electric system
c	parameter required to calculate coordinates of intersection (R_E, X_E)
$c_{original}$	($/MWh) original cost of generation
$c_{replacement}$	($/MWh) replacement generator cost
c_{load}	($/MW) large penalty due to customer load interruption
CDF	cumulative distribution function
DFIG	doubly fed induction generator
E_i	"N-1" contingency event due to occurrence of the fault F_i
EPCL	scripting language used in GE PSLF software
EWTGFC	electrical control model in PSLF
f_n	frequency of occurrence of each fault type
F_i	event of occurrence of a fault on the i^{th} circuit
F_{term}	terminal bus frequency
GE	General Electric

GENROU	round rotor generator model
GEWTG	generator/converter model in GE PSLF
GP1	under-frequency load shedding model in GE PSLF
h	outage duration in hours
i	index to denote a particular circuit
I_p	real power command from WTG electrical control model
I_q	reactive power command from WTG electrical control model
Imp	the impact of an event
Imp_i	the impact of transient instability for the i^{th} contingency
Imp_{gen}	the impact due to the replacement cost of generators being tripped
Imp_{load}	the impact due to customer load interruptions
k	index to denote the particular fault location
K	transient instability event
LSDT1	under-frequency load shedding model in GE PSLF
F_{WTG}	Cumulative distribution function for wind generation
L	# of segments in a circuit
LLG	two-phase to ground fault
LLL	three-phase to ground fault

LL	line-to-line fault
M	the total number of WTGs in the plant
m_L	parameter required to calculate coordinates of intersection (R_E, X_E)
m_R	parameter required to calculate coordinates of intersection (R_E, X_E)
n	index to denote the particular type of fault
N_c	total number of critical circuits considered in the evaluation
NERC	North-American Electric Reliability Corporation
OOS	out-of-step
P_{23}	Power flow from bus#2 to bus#3 in test system T3
P_{elec}	electric power signal from WTG converter model
P_{fault}	faulted electrical power output
P_g	generator MW tripped
P_{gen}	generator real power output
$P_{loadshed}$	total amount of load shed
P_{mech}	mechanical power
$P_{pre\text{-}fault}$	pre-fault electrical power output
$P_{post\text{-}fault}$	post-fault electrical power output

P_{ord}	power signal from WTG turbine control model
POI	point of interconnection
Pr	probability
PRC	protection and control
PSAT	power flow and short circuit analysis tool
PSLF	GE Positive Sequence Load Flow software
pu	per unit
PV	solar photo-voltaic
P^{w}_{WTG}	WTG generation as a percentatge of installed WTG MW capacity
Q_{gen}	reactive power output
Q_{max}	maximum reactive power output
Q_{min}	minimum reactive power output
Q_{ord}	Reactive power signal sent by WTG auxiliary Var control model
$RAPP$	apparent resistance
RBSA	risk-based security assessment

R_E	x co-ordinate of intersection of apparent impedance on line impedance line
rf	forward reach (pu Z) of the OOS circle characteristics
rr	reverse reach (pu Z) (positive is “behind” the bus) of the OOS circle characteristics
R_L	monitored transmission line resistance
R_t	apparent resistance at the ‘t’ instant of the postfault trajectory
SLG	single line to ground fault
SPS	special protection scheme
T1	synthetic test system
T2	reduced WECC system
T3	simple single machine test case
TPL	Transmission Planning
TSAT	transient security assessment tool
TSI	transient stability index
UFLS	under frequency load shedding
V_{POI}	voltage at the POI
$V_{reg\ bus}$	voltage at the bus to be voltage regulated
V_{term}	terminal bus voltage

w	the percentage of the rated capacity of renewable generation that is operational
WNDTGE	mechanical control (wind turbine) model in PSLF
WTG	wind turbine generator
X	pre-contingency operating point
$XAPP$	apparent reactance
X_E	x co-ordinate of intersection of apparent impedance on line impedance line
X_L	monitored transmission line reactance
X_t	apparent reactance at the 't' instant of the postfault trajectory
$Z_{apparent}$	apparent impedance
Z_{ef}	effective fault impedance representation for stability studies
Z_{neg}	negative sequence impedance
Z_0	zero sequence impedance
Z_L	monitored transmission line impedance
Z_t	apparent impedance at the 't' instant of the postfault trajectory
α	projections of Z_t onto orthogonal axis of Z_L
β	projections of Z_{t-1} onto orthogonal axis of Z_L
λ_i	fault rate in outages/hour

δ_{cr}	generator rotor angle in radians
δ_{cr}	criticial clearing angle in radians
δ_{max}	maximum angle separation between any two generators at the same time in the post-fault response
η	angular margin based transient stability index
ρ	operational risk metric
θ	the centerline angle of the OOS characteristic circle in degrees ($-180 \leq \theta \leq 180$)
ψ	number of deterministic positive sequence time domain simulations required for risk assessment

Chapter 1

INTRODUCTION

1.1 Overview

Power systems are regularly subjected to unanticipated and unavoidable events due to faults, disturbances, human errors and equipment failures. Such disturbances can cause overloads, voltage collapse or transient instability and can lead to widespread outages due to cascading failures. To maintain system reliability and security, system operators and planners perform analysis to make crucial operating and planning decisions that will guarantee safe operation of the power system following such faults/failures. The current practice within the power industry is the use of deterministic methods with significant safety margins to cover all potential uncertainties. Hence, with the adoption of a deterministic criterion for system security, power systems typically operate with a large security margin.

Power systems have shifted from a regulated system to a competitive and uncertain market environment where market prices for energy are defined by demand and supply. Deterministic security margins compel utilities to operate at levels much lower than their capability. This has led utilities to face more pressure to operate at lower security margins due to the economic imperatives in the power markets. Electric utilities require transparent and quantitative metrics to complement the security margins imposed on them. Hence, to operate the power system beyond the deterministic security margin, refined techniques are required in the planning stages to assess the security of the power system. Additionally, with increased penetration of converter-based renewable energy into the electricity grid, the overall dynamics of the system is changing. In the future with very high renewable generation penetration, it is imperative that the uncertainty (associated with variability and intermittency) and dynamics of such renewable generation are incorporated into the reliability standards.

The reliability requirement for operation and planning of the North-American Bulk Electric System (BES) is defined by the NERC Reliability Standards. The NERC transmission reliability standards [1] provide the requirements to develop a BES that will operate reliably over a wide range of operating conditions and probable contingencies within the planning horizon. The criteria requirements as defined in the NERC standards are deterministic and do not include any information about probabilities associated with the fault occurrence. Typically, these deterministic criteria provide safe but conservative limits for system operating conditions. The most crucial security criterion is the "N-1" security criterion that ensure safe operation of the power system following a failure of a single element of the system where N is the total number of system components. The deterministic "N-1" security criterion are obtained by determining the ability of the system to remain stable following the worst-case contingency from a credible list of contingencies. The operating condition, for which a system is secure for the worst case "N-1" contingency, is said to be "N-1" secure. "N-2" security of a system is assessed in a similar manner, although the probability of the simultaneous outage of two components is low if they are mutually exclusive.

1.2 Motivation

The deterministic security criterion estimation is intuitive and straightforward to implement but does not provide sufficient information on the actual risk of the violation of the criterion. With present changes in the electric power industry due to deregulation, utilities are compelled to operate very close to the deterministic security margins. Additionally, with increased penetration of converter-based renewable energy into the electricity grid, the overall dynamic performance of the grid is altered and the uncertainty of the variable generation needs to be incorporated, necessitating a probabilistic approach to characterize reliability standards. NERC acknowledges the need for probabilistic security standards for long-term planning to enhance the reliability metrics as highlighted in [2]. With the deterministic security criterion, an operating condition is considered as insecure if any operating constraints are violated. The extent of the violation is not considered in the deterministic approach and hence the system is either at risk or at no risk at all.

On the other hand, if the reliability standards are based on both the probability as well as the impact of the contingencies, then it provides a clearer picture of the extent of violation of constraints for a given operating condition. A 'risk' based index encompasses both the likelihood and consequence of an event and can relax the operating limits imposed by the deterministic approach. There is a fundamental difference between the deterministic approach and the risk-based approach for security assessment. The deterministic approach develops security limits based on the worst-case contingency while a risk-based security decision is determined by comparing the risk of all contingencies from a credible contingency list. Hence, the risk-based approach for security assessment can provide more information about the security margins obtained and can also quantify the bases on which security decisions are made. The risk of an event represents the expected cost due to possible insecurity problems measured by the economic consequence of an uncertainty weighted by its probability of occurrence [3]. Hence, with risk assessment system reliability and economics can be merged into a single metric. The most formidable problem of risk assessment is the quantification of the impact or consequence due to a power system disturbance.

1.3 Research scope and objectives

The overall objective of this report is to define new reliability standards for the dynamic security assessment of the power system based on risk-based criterion instead of traditional deterministic criterion. The work done in this dissertation has the following objectives:

- To define a new operational risk metric for transient instability dynamic security assessment
- To obtain a method for accurate impact assessment of a transient instability event by modeling specific protection systems in transient stability analysis
- To obtain the overall risk of transient instability on the system as well as the risk of transient instability for all credible contingencies
- To obtain system security limits for transient instability based on risk assessment
- To compare deterministic security limits with risk-based security limits
- Incorporate the stochastic model for renewable energy sources in reliability assessment

- To perform risk-based security assessment for the future electricity grid with high renewable penetration
- To incorporate the variation of wind generation and solar PV generation on risk assessment
- To develop an interactive diagnostics tool contingency ranking and impact analysis based on risk assessment

1.4 Dissertation organization

The report is organized as follows. Chapter 2 presents a detailed literature review of the existing work done in dynamic security assessment, risk-based security assessment and probabilistic transient stability studies. Chapter 3 presents the mathematical background for the risk assessment procedure and the derivation of the expressions for probability and impact of transient instability. Chapter 4 discusses the WTG models used in the simulations and the modeling of the protection system for impact assessment. Chapter 5 illustrates the detailed risk assessment procedure, test systems description and the detailed simulation results. Chapter 6 provides analytical explanations of the simulation results obtained using a simple one machine test case. Chapter 7 presents the RBSA diagnostics and contingency ranking interactive tool developed to investigate specific operating conditions. Chapter 8 summarizes the main conclusions of the research done on the development of a systematic approach to risk-based dynamic security assessment of the power system. In addition, this chapter discusses some of the future work that needs to be done for advancement of the proposed methodology. The appendices contain –

A. Fault rates of selected contingencies for the test system

B. CPU time metrics for RBSA methodology

C. Power flow data for one of the test system

D. Dynamic data for one of the test system

E. Out of step relay setting data, relay operation summary for a second test system

F. Scripts used to perfrom automated time domain simulation

G. MATLAB codes for risk calculations

H. MATLAB codes for plotting equal area criterion for a test case

I. R codes used to develop a diagnostics tool for RBSA.

Chapter 2

LITERATURE REVIEW

In this section, the previous work on probabilistic and risk-based methods for system security assessment is presented and discussed.

2.1 Dynamic security assessment

Dynamic security assessment (DSA) of the power system is the aspect of determination of the overall capability of a power system to withstand the transition, following a contingency, to a new steady state condition [4]. DSA has been a challenging problem in power systems research since late 1970 when fast and robust computation of dynamic security limits became essential as systems became large and complex. In [4], El-Kady et al. presented an efficient computerized technique for power system dynamic system security assessment using the transient energy function (TEF) method. Use of pattern recognition for fast transient stability analysis has been demonstrated by several efforts [5-9]. Recently, modern data mining approaches have been utilized in DSA along with phasor measurement unit (PMU) data [10-11]. The literature review of DSA shows that over time DSA has evolved to a more data-centric approach.

2.2 Probabilistic transient stability assessment

A significant amount of literature is available on probabilistic transient instability assessment. Anderson and Bose in [12] proposed a method for obtaining probabilistic transient stability assessment by using distribution functions based on location, fault type and sequence. Anderson, Bose and Timko in [13] demonstrated the use of Monte Carlo simulations in the computation of probabilistic measures for the transient stability problem. Billinton, Carvalho and Kuruganty, in [14], demonstrated approximate methods for evaluating probabilistic transient instability and identifying critical stability areas for system planning. In [15-16], Billinton and Kuruganty developed an approach for obtaining a stability index for individual lines as well as for the overall system for different fault types. The effect of clearing times and reclosing times were also investigated for critical lines. In [17], Billinton and Kuruganty proposed the use of stochastic models of protection system in probabilistic transient stability assessment by considering the probability density functions of the protection system components. Aboreshaid, Billinton, and Firuzabad, in [18], described the use of the bisection method for evaluating probabilistic transient stability.

In [19], Wu, Tsai, and Yu presented an approach to evaluate the distribution of the probability of instability. In [20], Hsu, Yun-Yih, and Chang used conditional probabilities in the evaluation of probabilistic transient instability.

2.3 Risk-based security assessment

In [3, 21-28], a risk-based security assessment of power systems is presented for operations and planning. In [21], McCalley, Fouad, Vittal, Irizarry-Rivera, Agrawal, and Farmer presented a risk-based security index for determining operating limits in stability-limited power systems. In [22], Acker, McCalley, Vittal, and Pecas Lopes presented a risk-based transient stability assessment procedure. The impact assessment was obtained through offline simulation with under-frequency relays by estimating the cost of load shedding. Generators going out-of-step were also considered in the impact estimation. Ming, McCalley, Vittal, and Tayyib, in [23], discussed the online evaluation of risk indices for security assessment. The EPRI report [3] by McCalley, Vittal, Dai, Fu, Irizarry-Rivera, Acker, Wan and Zhao provided a detailed discussion on risk-based security assessment for different aspects of power system performance. The report described the concepts and algorithms developed in building a decision-making framework for computing the risk associated with power system disturbances. The report discussed the risk assessment procedure for line overload, transformer overload, voltage instability, voltage limit violations, transient instability and special protection systems. In [25], Fu Zhao, McCalley, Vittal, and Abi-Samra presented a risk-based security assessment for special protection systems. Dissanayaka, Annakkage, Jayasekara, and Bagen, in [26], presented a linearized technique to determine a risk-based index for dynamic security. Abapour and Haghifam, in [27], presented a method for on-line assessment of the risk of transient instability.

2.4 Deterministic vs. probabilistic risk assessment

Vaahedi, W. Li, Chia and Dommel, in [29], presented the results of the probabilistic transient stability assessment on a large-scale system of B. C. Hydro and showed that deterministic criterion produces conservative results and that the deterministic criterion does not always correspond to the worst-case scenario. In [30], Maruejouls, Sermanson, Lee, and Zhang discussed the probabilistic reliability assessment using risk indices for overloads, voltage violations, voltage stability and load loss events. In [31], Kirschen, Jayaweera, Nedic, and Allan demonstrated the use of a probabilistic indicator based on ‘expected energy not served’ to estimate the level of system stress and its inverse - security. They suggested the use of the indicator in conjunction with deterministic criteria for the system operation decisions.

In [32], Kirsten and Jayaweera compared the differences between risk-based and deterministic security assessment methods and illustrated the benefits of risk-based security assessment over traditional deterministic approaches.

2.5 Security assessment with renewable generation

The United States electricity grid has witnessed increased deployment of renewable energy in recent years. In 2013, around 523 million MW-hours of energy produced in the United States were from renewable energy sources [33]. The major drivers for the increased renewable generation are the reduced cost of electricity production and the state-level renewable energy portfolio standards. The majority of the renewable energy penetration is in the form of utility-scale solar PV panels and type-4 wind turbine generators. The increased penetration of converter-based generation can have a significant effect on the transient stability of a power system. Most of the research efforts [34-38] in this area have focused on small signal stability analysis as well as transient stability analysis. The studies show that increased renewable penetration can have both beneficial and detrimental effects on system stability. Due to the altered dynamics of the system because of increased the converter-interfaced generation, it is essential that the reliability standards for transmission planning should be re-visited. In [39], Faried, Billinton, and Aboreshaid incorporated wind farms in the evaluation of the probabilistic transient stability of power system using a stochastic two-mass model of the WTG.

2.6 Summary

Most the literature on probabilistic and risk-based security assessment methods emphasize the benefit of the probabilistic methods over deterministic methods for security assessment. The present NERC reliability standards [1] for transmission planning are based on deterministic methods, but in [2] NERC mentions the need of probabilistic security standards for long-term planning to enhance resource adequacy metrics. With the recent trends in increased renewable penetration, stable operation of the power system will be dependent on a proper security assessment by system planners. The literature survey presented above also shows that in previous work the impact assessment is simplistic and is not evaluated for all fault types and fault locations.

Chapter 3

RISK-BASED TRANSIENT STABILITY ASSESSMENT

In this chapter, the theory behind risk-based security assessment (RBSA) of the transient instability problem is discussed. Risk is defined as the product of the probability of an occurrence of an event and the consequence of that particular event. The computed risk is equivalent to the expected cost of a transient instability event. The computed risk is useful in making system security decisions related to stability performance. The evaluation of the risk of transient instability is computationally intensive due to repetitive time domain simulations involved. In the following section, the mathematical expressions required to assess the transient instability risk is discussed.

3.1 Risk evaluation

The two main components of risk evaluation are the probability of occurrence of an event and the impact/consequence of that event [3, 22]. The following notations will be used in this report for the mathematical representation of the risk of transient instability:

F_i: event of occurrence of a fault on the i^{th} circuit

A: variable that denotes the type of fault. Three-phase to ground fault, two--phase to ground fault, phase-to-phase fault and one-phase to ground fault are represented by the indices 1, 2, 3 and 4 respectively

N_c: total number of critical circuits considered in the evaluation

E_i: "N-1" contingency event due to occurrence of the fault F_i

X: pre-contingency operating point

K: transient instability event due to one or more generators losing synchronism

Pr: probability

Imp: Impact

The risk due to a transient instability event *K* over the next time period at the pre-contingency operating point *X* due to all possible *N*-1 contingencies is evaluated as

$$\begin{aligned} Risk(K \mid X) &= Pr(K \mid X) Imp(K \mid X) \\ &= \sum_{i=1}^{N_c} Pr(K \cap E_i \mid X) Imp(K \cap E_i \mid X). \end{aligned} \tag{3.1}$$

3.2 Probability of transient instability

It is assumed that following a fault F_i the circuit is disconnected due to correct circuit breaker operation and the fault is cleared after a fixed interval of time-based on the voltage level at which the fault occurs. This event E_i is transiently unstable if one or more generators lose synchronism. Since the different types of faults (*A* = 1, 2, 3, 4) are mutually exclusive and exhaustive events, the following expression can be obtained

$$\begin{aligned} K \cap E_i &= K \cap E_i \cap \big((A=1) \cup (A=2) \cup (A=3) \cup (A=4)\big) \\ &= \big(K \cap E_i \cap (A=1)\big) \cup \big(K \cap E_i \cap (A=2)\big) \cup \big(K \cap E_i \cap (A=3)\big) \cup \big(K \cap E_i \cap (A=4)\big). \end{aligned} \tag{3.2}$$

Hence, the probability of transient instability can be expressed as

$$Pr(K \cap E_i \mid X) = \sum_{n=1}^{4} Pr(K \cap E_i \cap (A=n) \mid X). \tag{3.3}$$

The notation *X* for the operating condition is dropped in the following expressions due to the simplicity of notation.

$$
\begin{aligned}
Pr(K \cap E_i) &= \sum_{n=1}^{4} Pr\left(K \cap E_i \cap (A=n)\right) \\
&= \sum_{n=1}^{4} Pr(E_i) Pr\left((A=n) \mid E_i\right) Pr\left(K \mid E_i \cap (A=n)\right)
\end{aligned}
\tag{3.4}
$$

In addition, the probability of occurrence of a fault at different line locations is assumed to follow a uniform distribution; hence, the likelihood of occurrence of a fault on any part of the circuit is equal throughout the circuit. Hence, (3.4) can be re-written as follows:

$$
Pr(K \cap E_i) = \sum_{k=1}^{L} \sum_{n=1}^{4} Pr(E_{ik}) Pr\left((A=n) \mid E_i\right) Pr\left(K \mid E_i \cap (A=n)\right) \tag{3.5}
$$

where $Pr(E_{ik})$ is the probability of occurrence of a fault on the k^{th} section of the of the i^{th} circuit with L segments. From (3.5), it can be observed that there are three parts in the probability expression. In the following subsections, the detailed analysis of the probability expression in (3.5) is discussed.

3.2.1. Fault occurrence

The first part, $Pr(E_i)$ is the probability of occurrence of the considered N-1 contingency. Each line has a fault rate that can be obtained from historical data. It is assumed that the occurrence of a fault on the i^{th} circuit is a homogeneous Poisson process [3, 22]. Given the failure rate λ_i (faults/hour) of the i^{th} circuit, the fault probability of the i^{th} circuit is given as:

$$
\begin{aligned}
Pr(F_i) &= 1 - e^{-\lambda_i} \\
i &= 1, \ldots, N_c.
\end{aligned}
\tag{3.6}
$$

The time interval, in this report, is one hour and is decided by the choice of fault rates, λ, which are estimated in a number of events per hour. The occurrence of faults on different circuits are mutually independent of each other, hence the following expression can be derived [3, 22],

$$
\begin{aligned}
Pr(E_i) &= Pr\left(\overline{F}_1 \cap \overline{F}_2 \cap \cdots \overline{F}_{i-1} \cap F_i \cap \overline{F}_{i+1} \cdots \overline{F}_{N_c}\right) \\
&= Pr(F_i) \prod_{j \neq i} Pr\left(\overline{F}_j\right) \\
&= \left(1 - e^{-\lambda_i}\right) e^{-\sum_{j \neq i} \lambda_j} .
\end{aligned}
\tag{3.7}
$$

3.2.2. Fault location

To account for the influence of fault location on the probability of transient instability, a discrete uniform distribution is assumed. Since very few historical data are available on the locations of the faults on the lines, assuming that all locations of faults along the line have an equal probability of occurrence is a good engineering assumption. If appropriate historical information is available on fault locations on a circuit the information can be used without loss of generality. In this dissertation work, a uniform distribution is assumed for the fault location. Considering, each line has L segments, the probability of occurrence of the fault on the k^{th} section of the of the i^{th} circuit for the next unit time is given by

$$
Pr(E_{ik}) = \frac{\left(1 - e^{-\lambda_i}\right) e^{-\sum_{j \neq i} \lambda_j}}{L} . \tag{3.8}
$$

3.2.3. Fault type

The second expression $Pr\left((A = n) \mid E_i\right)$ in (3.5) denotes the probability of occurrence of a specific type of fault. Table 3.1 shows the different fault types with decreasing order of severity: three phase-to-ground fault (LLL), two phase-to-ground fault (LLG), line-to-line fault (LL) and single line-to-ground fault (SLG). In stability studies, the negative sequence and zero sequence voltages and currents are usually not of interest but their effects on faults are represented by equivalent impedance as seen from the point of fault. Depending on the type of fault, an effective impedance (Z_{ef}), measured in terms of negative sequence impedance (Z_{neg}) and zero sequence impedance (Z_0), is inserted in the positive sequence network as shown in Figure 3.1. Table 3.1 shows the effective fault impedances for different fault types for stability studies [42]. From historical data, the frequency f_n of occurrence of each type of fault can be obtained for the individual circuits. For each fault type, the probability expression is given by

$$Pr((A=n)|E_i) = \frac{f_n}{\sum_{n=1}^{4} f_n} \qquad n = 1,2,3,4 \tag{3.9}$$

Table 3.1 Fault representation in transient stability studies

n	**Fault type**	**Effective Impedance *(Z_{ef})***
1	LLL	0
2	LLG	$\frac{Z_0 Z_{neg}}{Z_0 + Z_{neg}}$
3	LL	Z_{neg}
4	SLG	$Z_{neg} + Z_0$

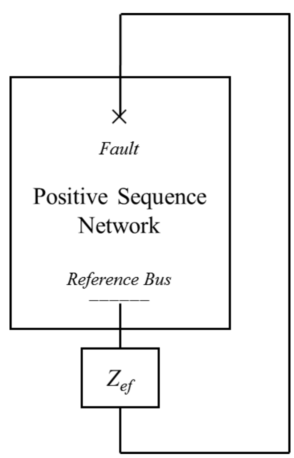


Figure 3.1 Fault representation in transient stability studies

3.2.4. Probability of transient instability

The third expression $Pr(K|E_i \cap (A=n))$ in (3.5) denotes the probability of transient instability of an event. The value of the expression is one if the system is unstable and zero if stable. The angle margin based transient instability index is used to distinguish between stable and unstable systems.

3.3 Stochastic modeling of wind power generation

The reliability of the power system is significantly impacted by the intermittent nature of any renewable energy injected to the grid especially the wind energy sources. The industry-wide deterministic reliability standards fail to incorporate the uncertainty associated with the wind power generation in operation and planning studies. With the adoption of renewable generation portfolio standards, large numbers of renewable energy sources are being added to the electricity grid. Hence, the variability of such sources should be modeled into the reliability standards for system planning. The current deterministic standards used in system planning consider only the worst-case scenario and do not incorporate the stochastic nature of the wind energy sources. In [38], the authors present the need of probabilistic wind energy modeling in reliability assessment. In this dissertation, to incorporate the stochastic nature of the wind energy an additional probability expression is introduced in (3.5). In [40, 41], the expression for the probability of transient stability incorporating the stochastic wind generation model is

$$Pr(K \cap E_i) = \sum_{k=1}^{L} \sum_{n=1}^{4} \sum_{w=0}^{100} Pr(E_{ik}) Pr((A=n) \mid E_i) Pr(P_{WTG}^{w}) Pr(K \mid E_i \cap (A=n)) \quad (3.10)$$

In (3.10), $Pr(P_{WTG}^{w})$ is the probability of wind generation output obtained from the probability distribution function and w is the wind generation output as a percentage of the installed wind capacity operational. The probability of wind generation output is evaluated from a fitted cumulative distribution function (CDF). Since, risk is estimated at discrete steps of wind generation penetration levels, the probability $Pr(P_{WTG})$ is also estimated for the specific wind generation level steps. For example, $Pr(P_{WTG} \; at \; w=15\%) = Pr(10<w\leq15) = F_{WTG}(15)-F_{WTG}(10)$ if the probabilities are estimated for every 5% step size, where F_{WTG} is the CDF for a wind generation farm. Figure 3.2 shows a typical fitted CDF of wind power output. The CDF can be obtained from historical data as well as forecasted wind power output. In this dissertation, the CDF is evaluated from historical data of a typical wind energy farm.

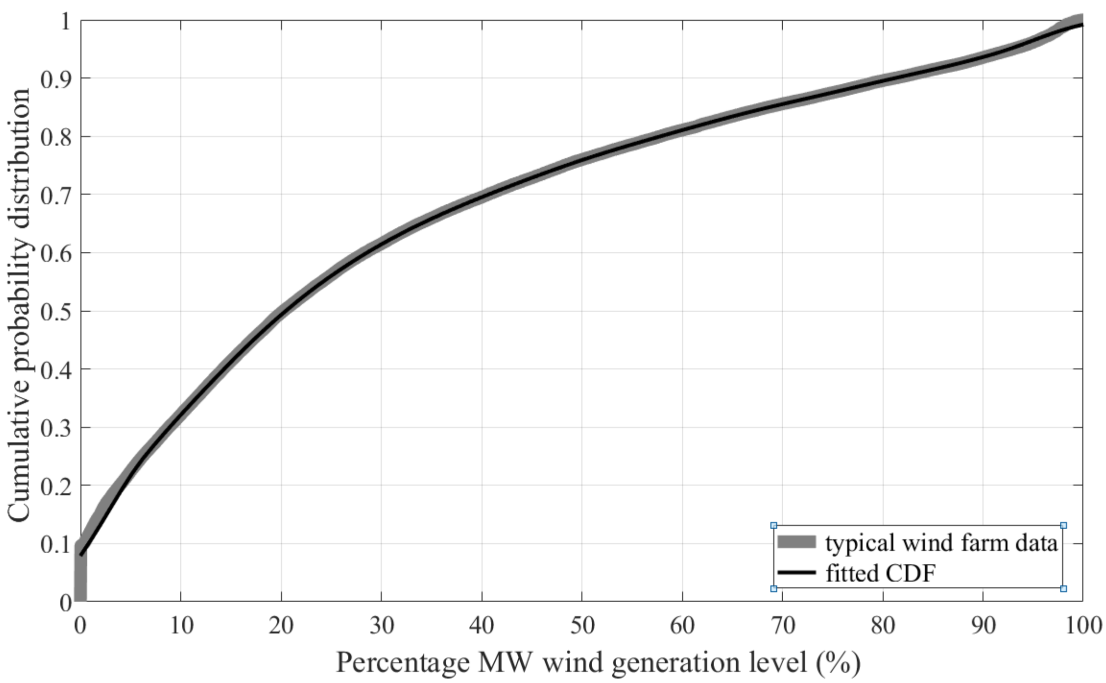


Figure 3.2 Cumulative probability distribution of a typical wind farm

3.4 Impact assessment of transient instability

The quantification of the impact/consequence of the transient instability is one of the most formidable problems in RBSA. In this dissertation, a novel procedure for determining the impact of transient instability is presented. Several critical protection systems are modeled such that following a contingency corrective actions are taken to move the system to a new stable operating point. The corrective actions (in terms of generation / load tripping) are used in the impact estimation. The following protection systems are modeled in this work [40,41]:

- Out-of-step (OOS) protection scheme for both transmission lines and generators
- Under-frequency load shedding
- Over/under-frequency generator tripping
- Over/under-voltage generator tripping.

OOS tripping is used to distinguish between stable and unstable power swings and initiate pre-determined network sectionalizing or islanding [43]. The NERC PRC standards [44] provide the required guidelines for automatic under-frequency load shedding. Over-frequency and under-frequency generator tripping is required to maintain generation-load balance [45]. Reference [44] also provide guidelines for over-frequency and under-frequency generator tripping. Due to tripping of generators, certain areas in the system can become generation deficit because of the loss of critical lines and out-of-step generators. To protect the system from frequency instability, under-frequency load shedding relays progressively remove the loads when the frequency drops below set thresholds. Based on time domain simulations, the total MW load shed and total generation MW tripped are used in estimating the impact of the transient instability event. Two methods have been analyzed for quantifying the impact of a transient instability event. The first method gives an economic perspective of the effort required to stabilize an unstable event while the second method estimates the expected unserved MW load following a transient instability event. The two impact assessment methods are explained in the next subsection.

3.4.1. Impact assessment: Method 1

The economic impact of transient instability can be represented as follows:

$$Imp_i = \sum_{k=1}^{L}\sum_{n=1}^{4} Imp_{gen} + \sum_{k=1}^{L}\sum_{n=1}^{4} Imp_{load} \tag{3.11}$$

where Imp_i is the impact of transient instability for the i^{th} contingency. Imp_{gen} is the impact due to the replacement cost of generators being tripped and Imp_{load} is the impact due to customer load interruptions. Assuming that original cost of generation is $c_{original}$ (\$/MWh), replacement generator cost is given by $c_{replacement}$ (\$/MWh), generator MW tripped is P_g and outage time is h hours, the expression for the loss of revenue due to generator tripping is given by [3, 22]

$$Imp_{gen} = \left(c_{replacement} - c_{original}\right) P_g h\,. \tag{3.12}$$

It should be noted that the replacement generation mentioned above is assumed to be available at the same location where generator outage takes place and is not imported from a diffent location. The effect of importing replacement generation from a different location is not modeled in this methodology. Due to tripping of generators, certain areas in the system can become generation deficit due to loss of critical lines and generators losing synchronism. To protect the system from frequency instability, under-frequency load shedding relays progressively remove the loads if the frequency drops below unacceptable values. The economic impact due to customer load interruption is estimated by the product of total load shed in MW and a large penalty factor due to load interruption in S/MW. The impact due to customer load interruption is given by [3, 22]

$$Imp_{load} = c_{load} P_{loadshed} \tag{3.13}$$

where c_{load} (\$/MW) is a large penalty due to customer load interruption, $P_{loadshed}$ is the total load shed. The modeling of the protection system for the impact assessment is discussed in detail in chapter 4.

3.4.2. Impact assessment: Method 2

It is proposed that the impact of instability is estimated by the corrective MW load shedding required for maintaining the system stability. Unlike the first method, it is not dependent on generation/load costs which are difficult to obtain in the planning stages. The operational risk metric ρ is estimated as the product of the corrective load shedding required for maintaining system stability in MW and the total probability of occurrence of the event given by (3.5) or (3.10). Hence, the operational risk metric ρ is defined as the expected value of MW load loss corresponding to the load shedding due to security preserving corrective control for the unit time interval [40, 41]. The operational risk metric ρ has the unit of MW as it is the probability weighted sum of all load loss events considered in the risk assessment procedure. The risk metric ρ described in this work is used only as a numeric identifier for ranking contingencies and can be used to differentiate between contingencies and operating conditions. The numerical value of risk metric ρ is low as it is a weighted sum of the actual impact (MW load loss) with different probability terms. In this methodology, no replacement generation is considered if a generator is tripped and the metric is solely based on MW load loss following an event.

Figure 3.3 provides an illustration of the effect of operational decisions on the risk metric for a typical system. The risk assessment can be performed for various operational decision variables like system loading, tie-line flows, generation levels and other similar variables. In this dissertation, two operational decision variables are considered in the risk assessment— i. system loading above base case and ii. renewable generation level. It can be observed that the risk metric is sensitive to the selected performance criterion.

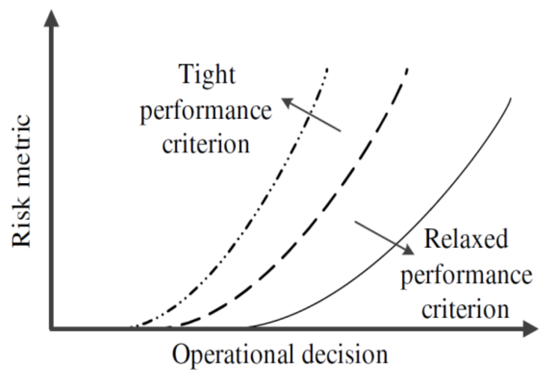


Figure 3.3 Risk metric vs. operational decision

3.5 Summary

In this chapter, the mathematical expressions for RBSA have been discussed. The probability of the occurrence of a transient instability event and its impact estimation methods are discussed in detail. Typical values of the different parameters for risk estimation are provided in Chapter 5. In the following chapter, the modeling of wind turbine generators and the protection system are discussed.

Chapter 4

MODELING OF WIND TURBINE GENERATOR AND PROTECTION SYSTEM

4.1 Modeling of wind turbine generators

The dynamic behavior of the WTG is significantly different from the conventional synchronous generators. Hence, the dynamic performance of the power system changes due to ever-increasing penetration of renewable generation in the form of WTGs. In this dissertation work, WTGs are modeled as type-4 [46-48] since it is the most widely used WTG technology worldwide. Type-4 WTG models have been developed to simulate the performance of wind turbines employing generators connected to the grid via power converters. Accurate WTG models are developed and maintained by the turbine manufacturers but those models are not publicly disclosed by them. This has led to the use of generic WTG models, which can capture the properties of most type-4 WTGs [46-48]. The modeling of WTG for time domain simulations mainly consists of two parts–

- Power flow model for WTG
- Dynamic model for WTG.

4.1.1. Power flow model for WTG

A wind plant for grid studies is modeled with a local grid collecting the output of individual WTGs at a single point of interconnection to the grid [46]. The multiple identical WTGs can be approximated to be in parallel to form a single equivalent machine behind an equivalent reactance. The power flow model of a wind plant is shown in Figure 4.1. The model consists of a single WTG with a unit transformer of *M* times the MVA rating of each individual WTG, where *M* is the total number of WTGs in the plant. For the power flow study, the wind farm is modeled as a conventional generator bus. The generator real power output (P_{gen}), maximum reactive power output (Q_{max}) and minimum reactive power output (Q_{min}) are set at M times the individual WTG unit capabilities. Typical collector system voltages are at distribution levels – 12.5 kV or 34.5 kV for 60 Hz application. The substation transformer ratings are dependent on the total number of WTGs in the plant with a typical impedance of 10%. In this dissertation work, WTGS are modeled as GE 1.5 MW WTG.

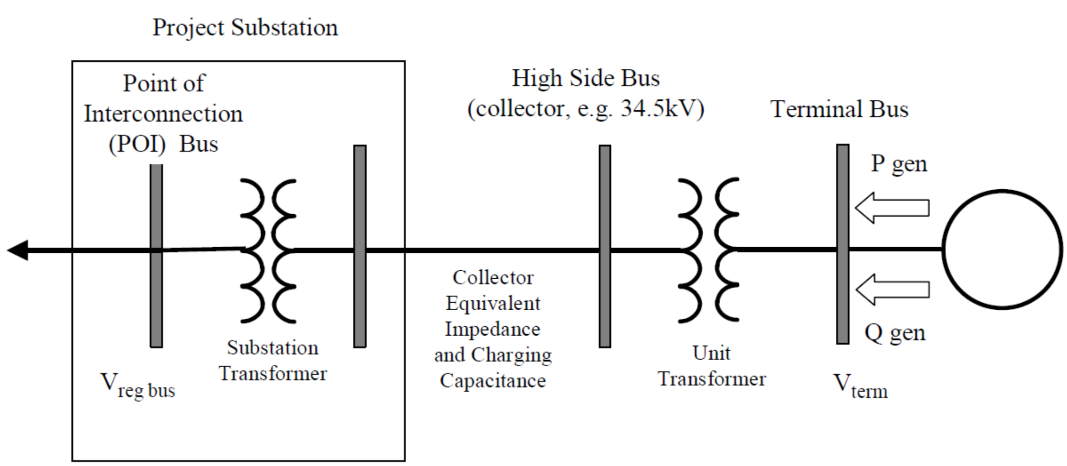


Figure 4.1 Simplified power flow model of a wind power plant, [46]

4.1.2. Dynamic model for type-4 WTG

The power flow solution provides the initial conditions for the dynamic model. The WTG dynamic model can be divided into four functional blocks as shown in Figure 4.2. The PSLF dynamic models for type-4 WTG are as follows [51]:

- GEWTG: generator/converter model
- EWTGFC: electrical control model
- WNDTGE: wind turbine and turbine control model.

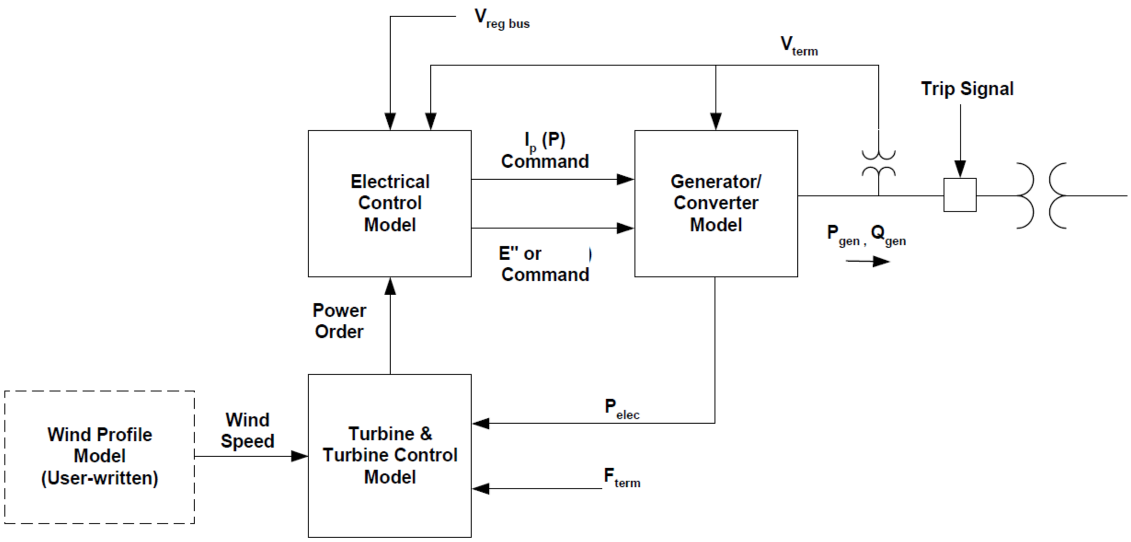


Figure 4.2 GE WTG dynamic model overall structure [46]

The generator/converter model injects real and reactive current into the network following commands from the other control blocks. The model also includes a low voltage power logic that is used to limit the real current command during and immediately following sustained faults [48]. The electrical control model includes reactive power control and voltage regulation.

4.1.3. GEWTG: generator/converter model

The WT3G model is an equivalent of the generator and the full converter providing the interface between the network and the WTG. This model contains no mechanical state variables. All flux dynamics are eliminated in the model to account for the fast response to the electrical commands from the electrical control model through the converter. The model is represented both by reactive and active current commands from the electrical control model [48].

4.1.4. EWTGFC: electrical control model

This model controls the active power and reactive power to be injected into the network based on the inputs from the turbine model (P_{ord}) and from the supervisory VAr controller (Q_{ord}) [48]. The model includes additional functions like dynamic braking resistor and converter current limit. The objective of the dynamic braking resistor is to minimize the WTG response to large system disturbances. The objective of the current order limit is to check and prevent the active and reactive power injections from exceeding the converter maximum capability. Active or reactive power can be prioritized by selecting a user-specified flag.

4.1.5. WNDTGE: wind turbine and turbine control model

This model represents the simplified mechanical dynamics of the wind turbine along with relevant control models.

4.2 Modeling of protection system

The aim of modeling the protection systems in this dissertation work is to quantify the impact of the transient instability event. The protection systems are modelled such that following a contingency the system should be transiently stable. In order to stabilize the system, three types of protection systems are modelled in this work [40, 41]:

a. Out-of-step (OOS) protection scheme for both transmission lines and generators

b. Under-frequency load shedding

c. Over/under-frequency generator tripping

d. Over/under-voltage generator tripping.

4.2.1. OOS protection modeling

The philosophy behind out-of-step protection is simple and straightforward: protect the power system during unstable power swings and avoid tripping of any equipment during stable power swings. When two areas of a power system or two interconnected systems lose synchronism, the areas must be separated quickly and in a controlled manner to avoid system blackout and damage to costly equipment. Controlled tripping of power system equipment will prevent widespread loss of load and maintain maximum service continuity.

OOS detection is based on the principle that the power swing is an electromechanical transient process has a longer time constant than that for faults and the positive sequence apparent impedance changes slowly during the power swing than during a fault. The fundamental technique to distinguish a fault from an OOS condition is to observe the rate of change of apparent impedance. There are two broad functionalities of OOS protection [43]:

- OOS tripping
- OOS blocking.

OOS tripping is used to distinguish between stable and unstable power swing and initiate pre-determined network sectionalizing or islanding. The OOS blocking function is used to distinguish between faults and power swings to avoid the faulty operation of distance relays during the power swing. In this work, only the OOS tripping function is implemented for impact assessment of transient instability. A simple impedance based OOS tripping relay is considered with concentric circle characteristics as shown in Figure 4.5.

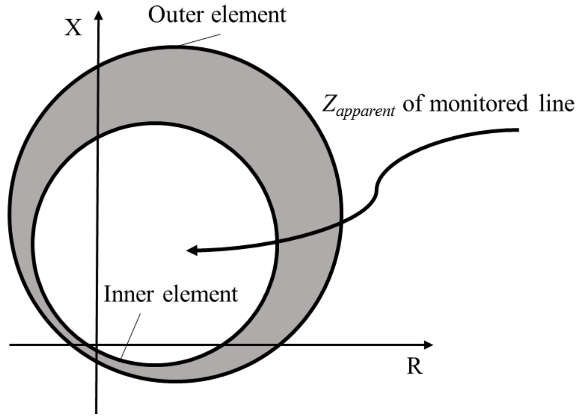


Figure 4.3 Concentric circle based OOS trip relay model

This relay has two elements an inner element and an outer element. The apparent impedance $Z_{apparent}$ of the monitored line is checked against these two elements. If $Z_{apparent}$ stays in the outer element for a specified time and then enters the inner element, a power swing is detected and a tripping signal is initiated. The block diagram of the OOS relay setting for a line connecting bus *P* and bus *Q* is shown in Figure 4.6.

RAPP+j*XAPP* is the apparent impedance *Z* of a monitored line #*P*-*Q*. The inner and outer element characteristics must be set according to the OOS relay settings. The model assumes that the inner element is entirely within the outer element. The output of these blocks has logical value: zero if the input ($Z_{apparent}$) is out of their circles or one if $Z_{apparent}$ is inside their circles. The OOS relay trips the line #*P*-*Q* and transfer trips lines #*R*-*S* and #*T*-*U* if the following conditions are met: $Z_{apparent}$ is in the outer element (but not in the inner element) for at least 3 cycles, and then $Z_{apparent}$ enters the inner element. The apparent impedance plots for stable and unstable swings for the line #*P*-*Q* are shown in Figure 4.7 (a) and 4.7 (b) respectively.

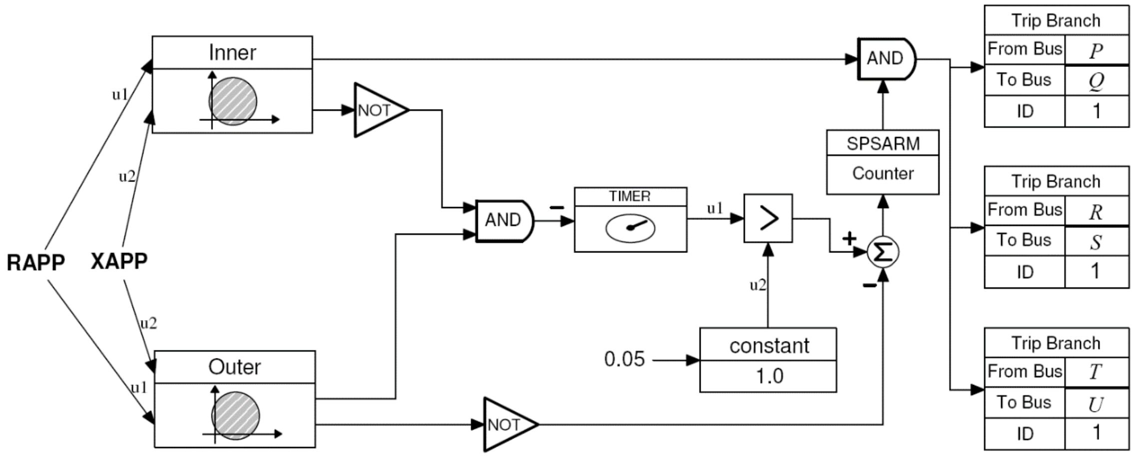
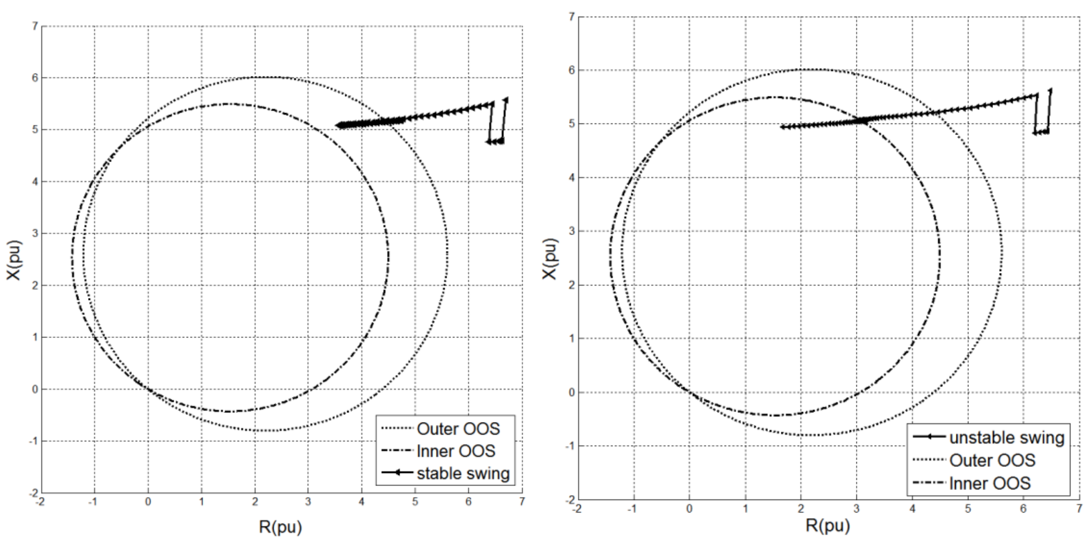


Figure 4.4 User defined model for OOS tripping for line #*P-Q*

The circular OOS characteristic function is defined by the parameters *rf*, *rr* and angle θ as illustrated in the Figure 4.8, where *rf* is the forward reach (pu *Z*), *rr* is the reverse reach (pu *Z*) (positive is "behind" the bus) and the angle θ is the centerline angle in degrees ($-180 \leq \theta \leq 180$).



(a) **(b)**

Figure 4.5 Apparent impedance during stable and unstable power swings

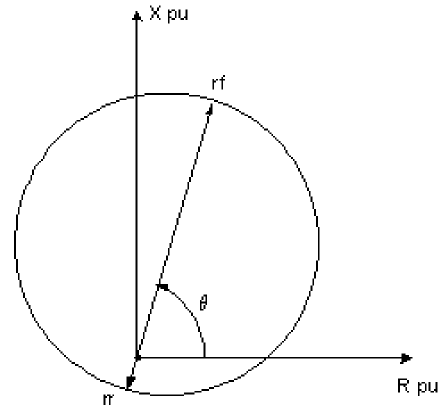


Figure 4.6 Circular OOS characteristic function

4.2.2. Electrical center detection in large power systems

Visual screening of all R-X plots to detect stable and unstable power swing can be a challenging task in large power systems, hence, computational techniques to detect electrical centers can be utilized. In [52], a systematic approach to locate all electrical centers in a transmission network is proposed based on the fact that if an electrical center exists on a transmission line, then the corresponding power swing plotted in the R-X plane cuts the transmission line impedance. The algorithm to detect electrical center on transmission line as explained below. For a given positive sequence time domain simulation, at the snapshot 't', the relay impedances of two consecutive time intervals are Z_t $(=R_t + jX_t)$ and Z_{t-1} where '$t-1$' denotes the first instant of the postfault trajectory. The projections $\alpha = -X_L{*}R_t + R_L{*}X_t$ and $\beta = -X_L{*}R_{t-1} + R_L{*}X_{t-1}$ onto the orthogonal axis of the transmission line impedance ($Z_L = R_L + jX_L$) are estimated. If α and β have opposite signs, then Z_t and Z_{t-1} are on the opposite sides of the transmission line impedance indicating that the possibility of an electrical center. If either of the projections are zero, then the corresponding point (R_E, X_E) lie on the transmission line impedance. For the case where, α and β have opposite signs, the coordinates of intersection (R_E, X_E) can be calculated by $R_E = c/(m_L - m_R)$ and $X_E = m_L*R_E$ where $m_R = (X_t - X_{t-1})/(R_t - R_{t-1})$, $m_L = X_L/R_L$ and $c = X_t - m_R*R_t$.

4.2.3. Under-frequency load shedding (UFLS)

The primary requirement of UFLS is to trip excess load to obtain generation-load balance following a disturbance that results in tripping of lines and/or generators causing that area generation deficit [43]. Since generator turbines cannot operate at low frequencies (56-58 Hz), it is necessary to maintain frequency near the nominal frequency (60 Hz). Slow changes in load can be compensated by the system by governor action if generators have available spinning reserve and equilibrium can be reached. However, during transient outages, the excess load is fed by the available kinetic energy of the rotating machines and frequency starts dropping. The only way to stabilize the system under such conditions is progressively shedding the load at pre-determined load centers at certain frequency thresholds.

The NERC reliability standard [44] for the Eastern Interconnection provides the required guidelines for automatic under-frequency load shedding. Table 4.2 shows the UFLS criterion for the Eastern Interconnection for utilities with net peak loads greater than 100 MW.

Table 4.1 UFLS attributes for with net peak load greater than 100MW

Frequency Threshold (Hz)	**Total Nominal Operating Time (s)**	**Load Shed at Stage (%)**	**Cumulative Load Shed (%)**
59.5	0.07	10	10
59.2	0.07	20	30
58.8	0.07	20	50

4.2.4. Over/under-frequency and over/under-voltage generator tripping

Over-frequency and under-frequency generator tripping is required to maintain generation-load balance [43]. If any area is load deficit, the generators start speeding up. The generator turbines are designed to operate near nominal frequency and operation at an off-nominal frequency can damage the turbine blades. To protect the costly turbine generators, the NERC reliability criteria for UFLS [44] also provide guidelines for over-frequency and under-frequency generator tripping. Figure 4.9 shows the generator over-frequency and under-frequency performance characteristics and trip modeling criteria. In this work, the generators modeled with over-frequency and under-frequency relays are tripped if the over-frequency threshold of 61.2 Hz for 2 s is violated or the under-frequency threshold of 58.2 Hz for 2 s is violated.

Generators are designed to operate at a continuous minimum terminal voltage of 0.95 pu of its rated voltage, while delivering power at rated voltage and frequency. Under-voltage can reduce the stability limit, result in excessive reactive power import and malfunctioning of voltage sensitive equipment. In this dissertation, if the generator terminal voltage reduces to 0.90 pu for 1.0 s, then the generator is tripped. Generator overvoltage protection, on the other hand, is required to prevent insulation breakdown due to sustained terminal overvoltage. The generator insulation is capable of operating at continuous over-voltage of 1.05 pu of its rated voltage. If the generator terminal voltage increases to 1.15 pu for 0.5 s, the generators are tripped.

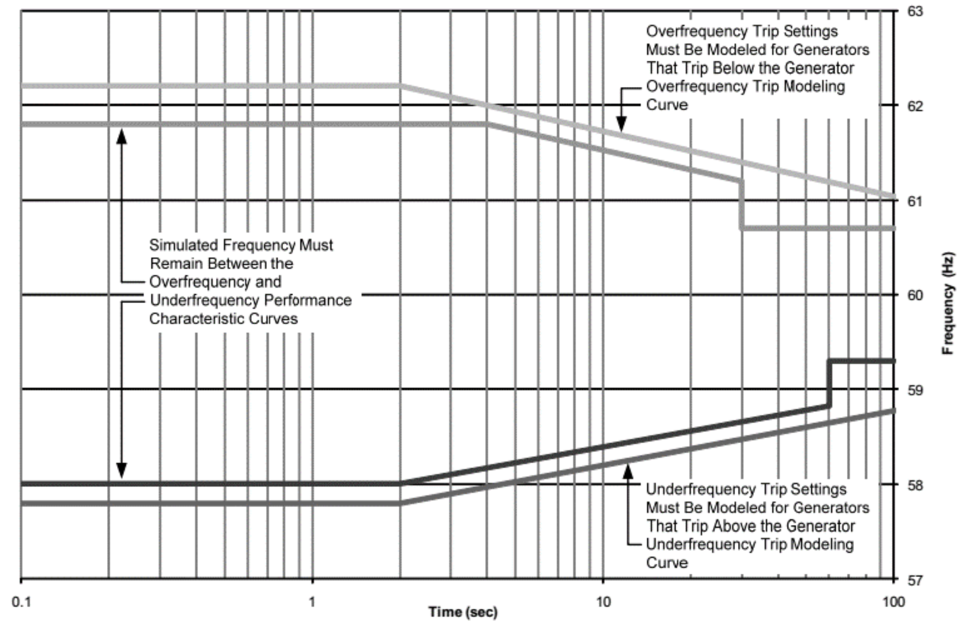


Figure 4.7 Design performance and modeling curves for over and under frequency generator trip [44]

4.3 Summary

In this chapter, the mathematical modeling of WTGs and protection systems required for risk based transient instability assessment are discussed. RBSA simulation procedures and results are provided in the following chapter.

Chapter 5

RBSA SIMULATIONS AND RESULTS

This chapter provides the detailed simulation results of RBSA for transient instability. The test is performed on the test system as described in the previous chapter. The research encompasses the evaluation of risk indices of transient instability for security assessment. The study is conducted using analytical tools from the GE PSLF software. The simulations are automated using EPCL [51] based scripting available in the PSLF package. The automated EPCL scripts export transient stability simulation results into data files. Another MATLAB code is used to read the data files for risk assessment and generation of plots and graphs.

5.1 RBSA procedure

The flow chart of the overall procedure to evaluate risk based transient instability is provided in Figure 5.1. A set of credible contingencies is selected for voltage levels greater than 100 kV. For each credible contingency, exhaustive positive sequence time domain simulations are performed for different fault types (three-phase fault, double line-to-ground fault, line-to-line fault and single line-to-ground fault) and at different fault locations (near bus, far bus and center) for lines and at two ends of all transformers. The protection systems listed earlier are modeled such that for all credible contingencies corrective actions are taken such that system settles to a new stable operating point. The impact of a fault is determined by the effort in tripping generators and loads to maintain stability. The generator tripping and load shedding data for the contingency is used to evaluate the impact of transient instability. For each contingency, the risk is evaluated for different operating conditions. The simulations are performed at different system loading levels and with varying wind generation output at each loading level.

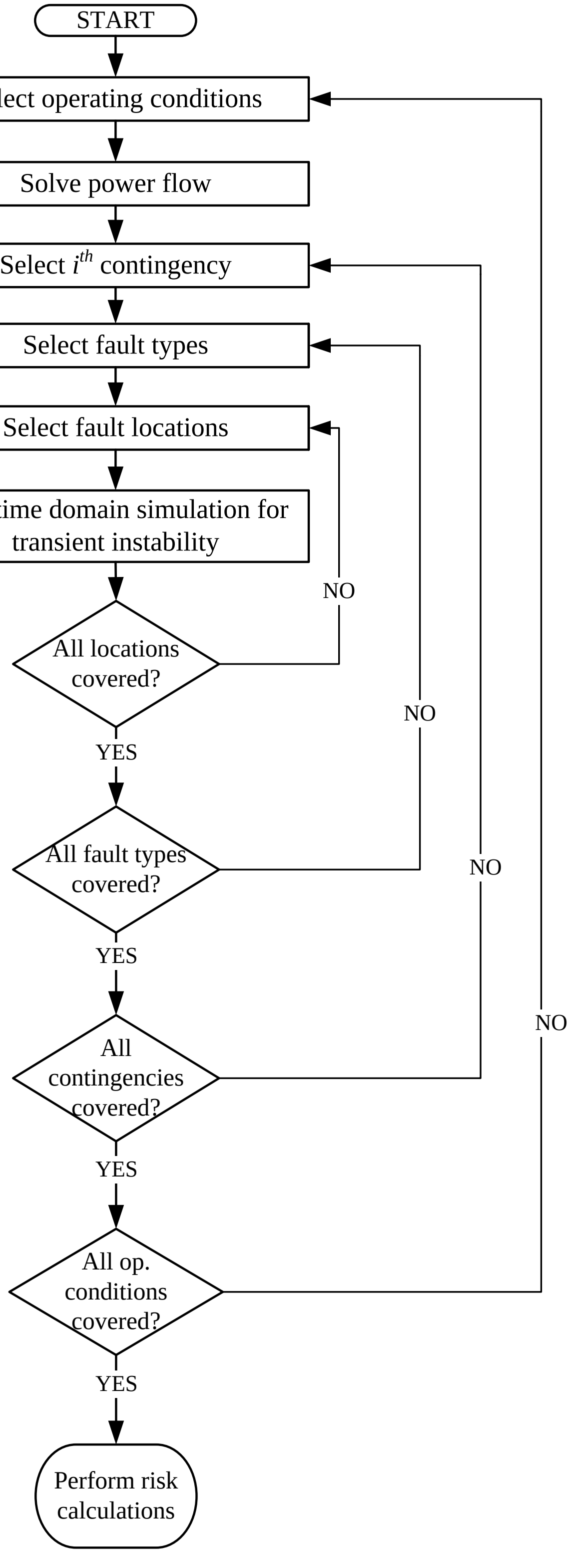


Figure 5.1 Flow chart for risk-based transient instability assessment

Using realistic statistical data from the Canadian Electricity Authority [55], the probabilities of transient instability are calculated. The overall risk of the system with all contingencies considered is also evaluated for different operating conditions. The uncertainty of the injected wind power is also incorporated into the risk calculation using a simple stochastic model of the wind generation output. Equal risk contours are plotted to illustrate the effect of system loading and renewable generation on system risk and hence on system reliability.

5.2 System description

A synthetic test system (T1) is generated to perform the risk-based transient stability assessment. The synthetic system is generated to represent a realistic test system consisting of all the major features of a realistic power system for transient stability and reliability studies for system planning. The single line diagram of the test system is shown in Figure 5.2. The system consists of 11 conventional synchronous generators with detailed generator, governor and exciter models. The total installed capacity of conventional generation (17,000 MW). Renewable generation in the form of type-4 WTG is added at different locations within the test system with installed capacity of 1,680 MW. Table 5.1 provides the details of the generators in the test system T1. The test system is divided into 5 distinct zones to illustrate the risk-based transient stability assessment method. The risk is evaluated for each zone separately which can help in identifying the highest risk and lowest risk zones. The detailed system model is provided in the Appendices.

Table 5.1 Details of the installed generators in the test system

Bus	Generator type	Capacity (MW)	PSLF models	Bus	Generator type	Capacity (MW)	PSLF models
1	hydro	2000	genrou, exst1, hygov	8	WTG type-4	300	gewtg, ewtgfc, wndtge
2	hydro	2000	genrou, exst1, hygov	28	WTG type-4	150	gewtg, ewtgfc, wndtge
4	coal	1000	genrou, exst1, tgov1	29	WTG type-4	150	gewtg, ewtgfc, wndtge
5	coal	1000	genrou, exst1, tgov1	30	WTG type-4	150	gewtg, ewtgfc, wndtge
7	gas turbine	1000	genrou, exst1, ggov1	31	WTG type-4	150	gewtg, ewtgfc, wndtge
11	gas turbine	500	genrou, exst1, ggov1	32	WTG type-4	150	gewtg, ewtgfc, wndtge
14	nuclear	2000	genrou, exst1, tgov1	33	WTG type-4	105	gewtg, ewtgfc, wndtge
20	coal	1500	genrou, exst1, tgov1	34	WTG type-4	200	gewtg, ewtgfc, wndtge
22	coal	2000	genrou, exst1, tgov1	35	WTG type-4	200	gewtg, ewtgfc, wndtge
24	coal	4000	genrou, exst1, tgov1	36	WTG type-4	105	gewtg, ewtgfc, wndtge
26	coal	1000	genrou, exst1, tgov1				
TOTAL		17,000		TOTAL		1,680	

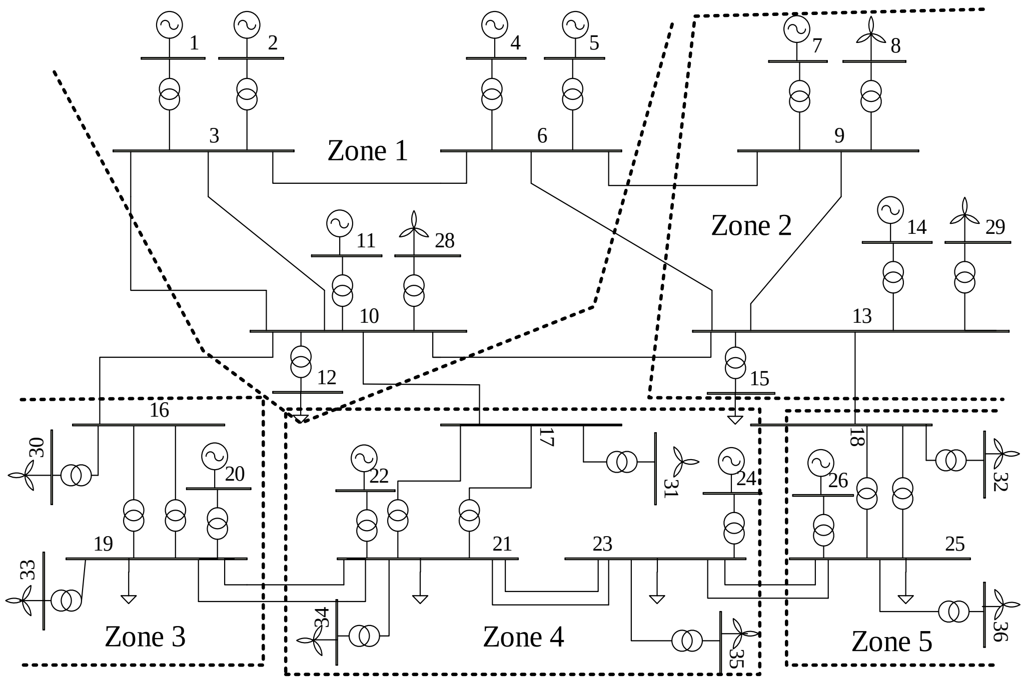


Figure 5.2 Synthetic test system for RBSA [40, 41]

Table 5.2 Test system T1 summary

Buses	56
Generators	11 (synchronous) +10 Wind farms
Lines	30
Total synchronous Generation	17,000 MW installed capacity
Wind Generation	1,680 MW installed capacity

5.3 Operating conditions

The base case of the test system T1 is stable for all credible first contingencies. To generate the set of different operating conditions the system loading is varied from the base case loading. Designating 100% loading as the base case loading, the system loading is increased in steps of 5% until 185% above the base case. The generators are dispatched in accordance with each load scenario. For each loading scenario, the wind generation injected into the system is also varied from 0% to 100% in steps of 10%. Hence, we obtain a grid of scenarios to perform the simulations. As the wind power injection in increased, the conventional synchronous generators are rescheduled to produce less in order to maintain the generation-load balance.

5.4 Credible contingency selection

The preliminary set of contingencies is selected by finding all transmission line and transformers above 100 kV. This preliminary contingency list is used to run the worst-case faults (3 phase-to-ground fault on the terminal buses) at the highest operating condition possible (185% loading above the base case). Those contingencies that are transiently unstable for the worst-case test mentioned above are considered as credible contingencies. This worst-case test led to 19 overall contingencies (14 transmission line contingencies and 5 transformer contingencies) which are used for the risk assessment procedure. The contingency list is provided in Table A.1 and Table A.2 of the Appendix A. Further, in the RBSA procedure for varying loading conditions – three-phase faults are first considered near the terminal buses, if these three-phase faults trigger generator tripping/load shedding, only then other fault types are considered. These filters are already implemented in the RBSA and help in reducing the computational burden by not simulating cases, which do not cause transient instability problems. Further simplifications are also possible to incorporate in the RBSA methodology, for example, the bisection method based approach can be used to minimize the risk calculation for all possible loading levels.

5.5 Parameters used in risk assessment

In this section, the detailed list of parameters used for the risk assessment of the test system is provided.

5.5.1. Fault rates of transmission lines

The fault rates for different lines are required to evaluate the probability of transient instability as shown in (3.7). The Canadian Electricity Authority 2012 annual report [55] provides transmission system reliability statistical data. The transmission line statistics for line-related transient forced outages data provides the frequency of outage of transmission lines for different voltage levels in number per 100 mile-annum. For transformers, the fault rates are available as per the voltage ratings as shown in Table 5.3. The fault rates of the transmission lines in outages/hour are evaluated based on the line lengths.

Table 5.3 Transient forced outage statistical data, from [55]

Transmission lines		**Transformers**	
Voltage classification	**Frequency (number / 100 mile-annum)**	**Voltage classification**	**Frequency (number / annum)**
100 kV	1.3573	100-199 kV	0.1143
220 kV	0.7548	500-599 kV	0.1364
345 kV	0.1506		
500 kV	1.8535		

5.5.2. Probability of fault types

The fault type probabilities assumed for the risk assessment discussed in this work is given in Table 5.4. These values are usually obtained from historical data. The SLG fault has the highest probability of occurrence while the three-phase fault is the least probable.

Table 5.4 Fault type probabilities

n	**Fault type**	**Fault Probability (%)**
1	LLL	6.2
2	LLG	10.0
3	LL	8.8
4	SLG	75

5.5.3. Fault location probability

A discrete uniform distribution is adopted in the risk assessment procedure where each of the 14 lines is divided into 2 segments. Hence, 3 line fault locations exist – 0.1%, 50% and 99.9%. The severity of the fault diminishes towards the center of the line and the faults near the terminal buses (0.1% and 99.9% location) are the most severe. Equal probability of occurrence of the fault throughout the line is considered. If data for the frequency of fault occurrence for different line locations are available, it can be easily incorporated into the probability calculations.

5.5.4. Fault clearing time

It is assumed that following any fault the circuit breakers open and clear the fault in 5 cycles. A fixed clearing time of 5 cycles is considered for all contingencies. Based on the operating voltage level of the line considered, the fault clearing time can be changed without any loss of generality. In this dissertation, the simulations are performed in GE PSLF for four different fault types at different locations with 5 cycles fault clearance. Although PSLF does not provide the stuck breaker simulation as a default option, it can be modeled by clearing the furthest bus at a nominal clearing time of 5 cycles while delaying the fault clearance in the near bus to 10-16 cycles and initiating adjacent breakers to operate. Since the proposed RBSA method incorporates modeling of the protection system to evaluate the impact, any type of contingency that can be simulated in time domain simulation can be analyzed using the RBSA and its impact can be assessed through the tripping of generation/load.

Also, for contingencies resulting in cascading events where the loss of transient stability occurs during the cascade but not directly caused by an initial short circuit, the RBSA method can be used if the protection system is modeled such that cascading events can be simulated in time domain simulation. Some, initial short circuits can trigger cascading failures which are observed in the simulations. Such cases were included in the RBSA. In such cases, the length of the time domain simulation is increased for the system to settle to a new operating condition.

5.5.5. Wind generation stochastic model

To incorporate the stochastic model of wind power generation, a probability density curve of a typical wind power plant is obtained from historical data. In this research, a typical wind farm data from Australian Energy Market Operator (AEMO) is used to obtain the probability density curve and cumulative density curve. The cumulative density curve is fitted to get the CDF for wind power generation as shown in Figure 3.2 in chapter 3.

5.5.6. Impact assessment parameters

For each particular fault, the impact of transient instability is obtained based on the special protection system (SPS) operation action report obtained from the time domain simulations. The impact (Method I) is assessed based on the generator tripping and load shedding information. The impact of each contingency for a particular fault type and fault location is calculated as in (3.10-3.12). Table 5.5 shows the different parameters used for impact estimation. The parameters are in line with previous works on RBSA for transient instability [3, 22] and the Ontario Power Authority website [56]. To evaluate the impact by Method 2, no additional parameters are required.

Table 5.5 Impact assessment parameters

Generator outage duration *h*	10 hours
$c_{replacement}$ –cost of replacement generation	85 $/MWh
$c_{original}$– original cost of generation	60 $/MWh
c_{load} – penalty due to load interruption	1000 $/MW

5.6 Deterministic transient instability criterion

The deterministic "*N*-1" security criterion is assessed by evaluating the worst-case contingency. The worst-case contingency for the test system is obtained by progressively increasing the loading of the system from base case and running time domain simulations for all credible contingencies for the three-phase faults near the terminal buses (0.1% and 99.9% location). When the system becomes "*N*-1" transiently unstable, the particular contingency, which makes the system unstable is defined as the worst-case contingency. The highest system loading at which the system is "*N*-1" stable is defined as the deterministic security limit. For the test system, the limiting operating condition occurs at a loading level 33.0 % above the base case due to contingency#1 –three-phase fault near bus #6, cleared by opening line # 3–6 after 5 cycles. Figures 5.3 and 5.4 show the rotor angle plots for all the 11 generators for contingency #1 at the limiting loading cases. The generators at bus #4 and bus #5 lose synchronism and system become unstable at a load 34% above base case. Hence, the deterministic "*N*-1" security margin of the system for transient instability is 33.0% above the base case loading.

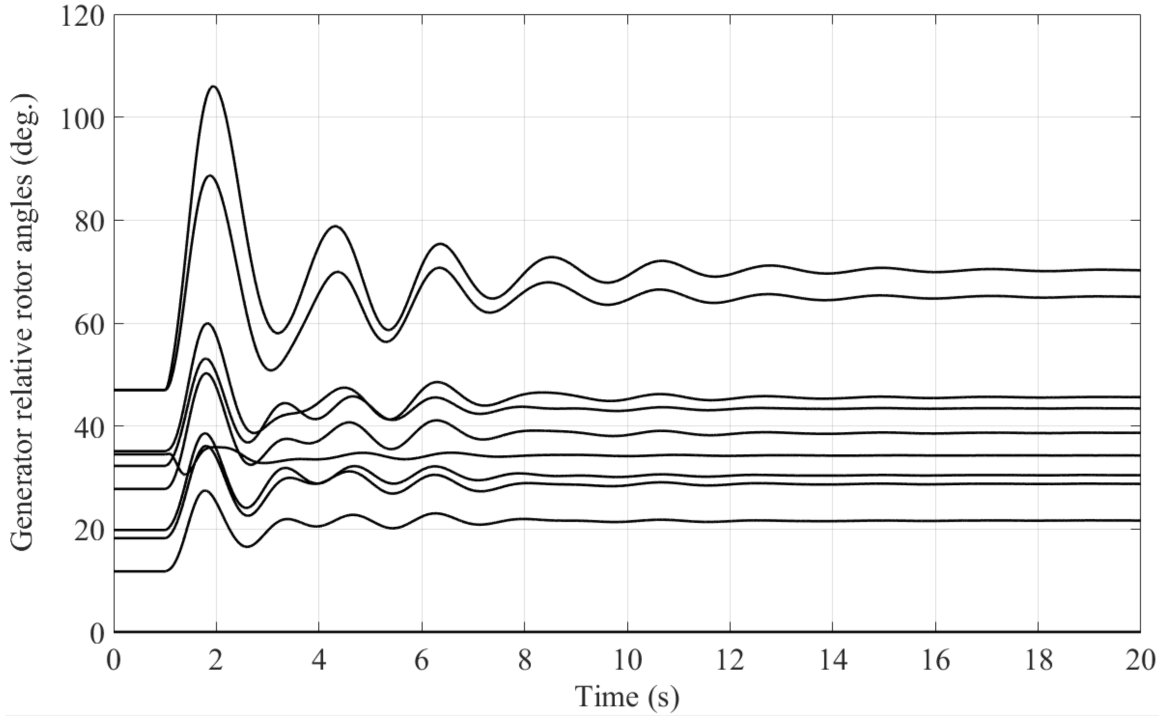


Figure 5.3 Relative rotor angles of the generators for a loading 33.0% above the base case

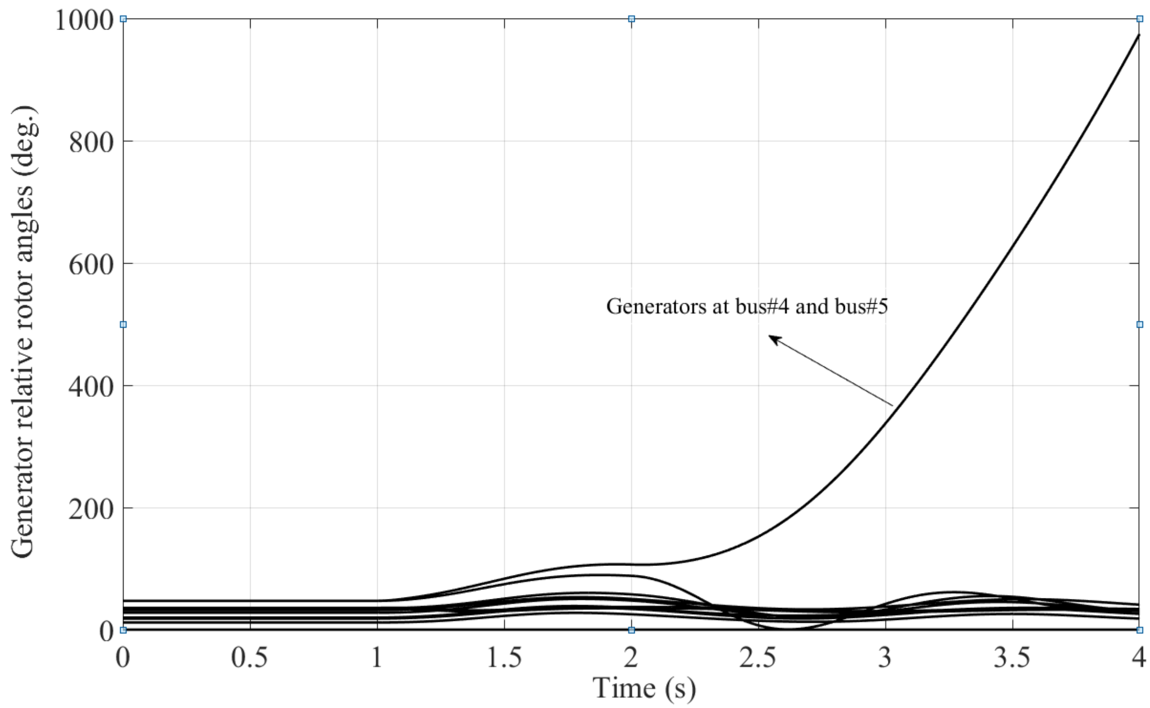


Figure 5.4 Relative rotor angles of the generators for a loading 34.0% above the base case

5.7 Risk-based security assessment for transient instability

This section illustrates the detailed results of the risk-based security assessment for transient instability. The operational risk metric ρ values at each operating condition are estimated by conducting ψ number of deterministic positive sequence time domain simulations event by event [40, 41]. The generic expression for the number of time domain simulations required is given by (5.1),

$$\psi = PQR\left(\left(S_{line}T_{line}\right) + \left(S_{xfmr}T_{xfmr}\right)\right). \tag{5.1}$$

In (5.1), (P = 18) denotes the number of loading scenarios, (Q = 6) denotes the wind generation levels, (R = 4) denotes the fault types, (S_{line} = 14) denotes the number of transmission line contingencies considered, (S_{xfmr} = 5) denotes the number of transformer contingencies considered, (T_{line} = 3) denotes the fault locations on the transmission lines and (T_{xfmr} = 2) denotes the fault locations on the transformers. Hence, a total of 22,464 deterministic simulations are required to be performed to obtain the risk contours. However, to reduce the computational burden in the RBSA procedure, the three-phase faults near the terminal buses are first considered, if these three-phase faults trigger generator tripping/load shedding, only then other fault types are simulated.

The exhaustive time domain simulations provide a measure of risk for two varying operating parameters – system loading above base case and amount of renewable injection. Figure 5.5 and Figure 5.6 shows the mesh plot of system overall risk with percentage loading above base case in the x-axis, MW renewable generation in the y-axis and the risk is the z-axis. In Figure 5.5, the risk is estimated using in $/hour with impact modeled as per method I and in Figure 5.6, the risk is estimated in terms of risk metric ρ with the impact modeled as per method 2. The risk estimated using method 2 consists of only load shedding information and the load shedding variable is weighted by a large penalty factor and hence, the risk characteristics of both methods are similar. It should be noted that an operating condition that depicts a high operational risk in Figure 5.5 may have only a low financial risk in Figure 5.6 if the cost parameters are varied. Figure 5.7 shows the financial risk of the system at 672 MW of wind generation for different penalty costs due to load interruption. It can be observed that the financial risk metric is highly sensitive to the choice of the cost parameters. The risk metric ρ, on the other hand, is insensitive to any cost parameter and provides a risk value determined by operational conditions. In order to maintain consistency, all risk values are expressed in terms of the operational risk metric ρ, henceforth, in the report. From Figure 5.5, it can be seen that the risk increases sharply when the system is loaded 150% above base case. In addition, it can be observed that higher the renewable power injection; lower is the system risk due to transient instability. The results show that converter-based generation has a significant effect on the system risk and hence on the system reliability [40, 41].

The operation of the protection system of the highest risk contingency risk contingency at the limiting operating condition (165% of base case and 0 MW renewable injection) is tabulated in Table 5.6. It can be seen that 1183.2 MW of generation is tripped and 1182.2 MW of load is tripped to maintain stability. Table 5.7 shows the operation of the protection system for the deterministic worst-case contingency at the limiting operating condition (135% base case loading and 0 MW renewable injection). It can be observed that only 986.6 MW of generation is tripped but no load has been shed. The governors of the other generators are able to increase the mechanical power input to stabilize the system and load shedding is not required. Hence, the impact of the deterministic worst-case contingency is less on the system for a transient stability event. In addition, from Appendix A - Table A.1 it can be observed that the fault rate of the worst-case line is lower than the highest risk contingency line. In this case, both the probability of occurrence of fault and impact of transient stability influences the risk estimate.

Table 5.6 Protection system activated for highest risk contingency (Contingency #6, fault on line #9-13) at 165% base case loading

Gen bus	**time (s)**	**Protection operated**	**MW tripped**	**Total tripped (MW)**
4	2.488	under-voltage (GP1)	591.6	1183.2
5	2.488	under-voltage (GP1)	591.6	
Load bus	**time(s)**	**Protection operated**	**MW shed**	**Total shed (MW)**
19	5.384	under-freq (stage 1 LSDT1)	268.5	1182.2
21	5.376	under-freq (stage 1 LSDT1)	259.8	
23	5.288	under-freq (stage 1 LSDT1)	394.1	
25	5.388	under-freq (stage 1 LSDT1)	259.8	

Table 5.7 Protection system activated for deterministic worst-case contingency (Contingency #1, fault on line #3-6) at 135% base case loading

Gen bus	**time (s)**	**Protection operated**	**MW tripped**	**Total tripped (MW)**
4	2.088	under-voltage (GP1)	484.3	968.6
5	2.088	under-voltage (GP1)	484.3	
Load bus	**time(s)**	**Protection operated**	**MW shed**	**Total shed (MW)**
-	-	-	0.0	0.0

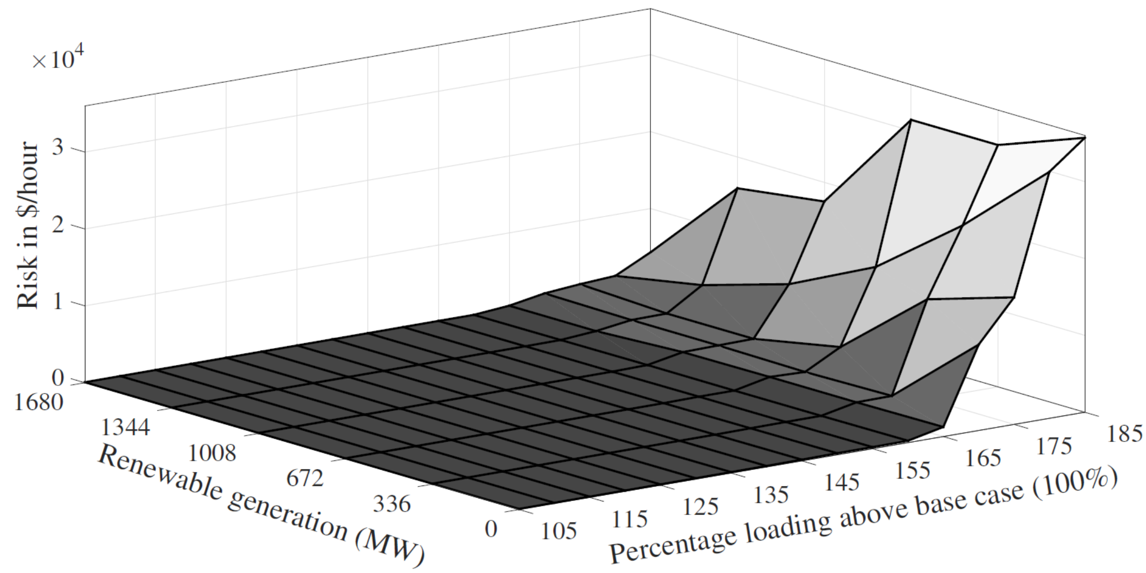


Figure 5.5 Overall risk of the system in $/hour for varying load and wind power injection

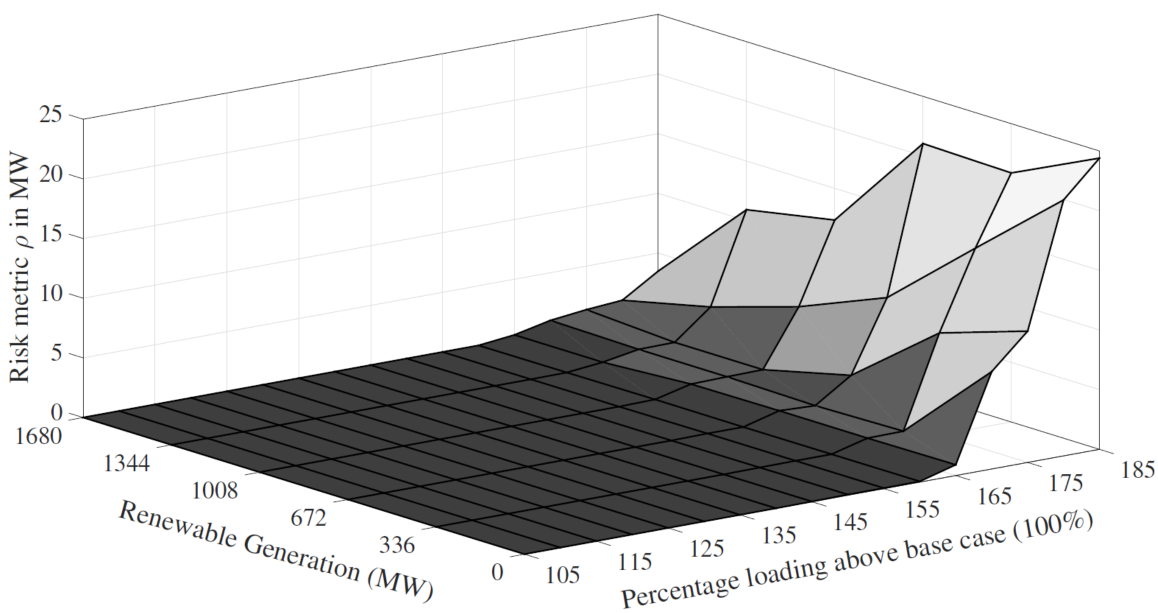


Figure 5.6 Overall risk metric ρ of the system for varying load and wind power injection

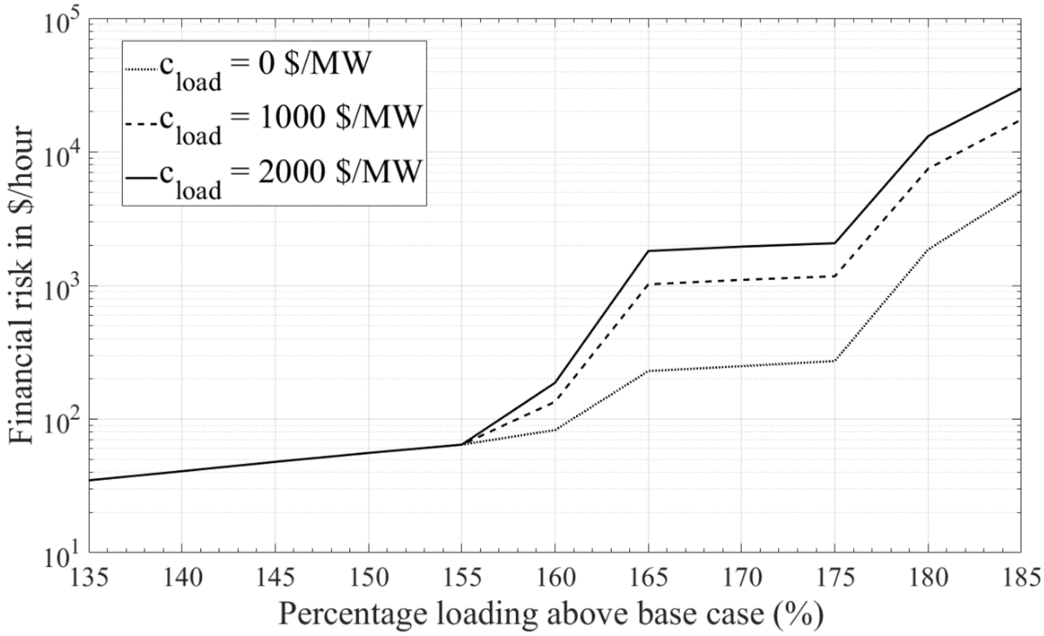


Figure 5.7 Financial risk of the system at 672 MW of wind generation for different penalty costs due to load interruption

5.7.1. Equi-risk contours

Figure 5.8 shows the equal risk (equi-risk) contours for varying system loading and varying wind power injection. The safe operating region can be easily identified from the equal risk plot. The lines represent the equal risk contours and the number on the line represent the value of risk. For example, after 165% of base case loading and 0 MW renewable generation, the risk metric value is 1.5. The risk metric value is 1.5 till 177% of base case loading and 1680 MW renewable generation. The equi-risk contours provide a detailed illustration of the risk of an operating point and the sensitivity of operating conditions on the risk metric [40, 41]. It can be observed from the figure that the equi-risk contours have positive slopes indicating that the presence of converter-interfaced generation can reduce the estimated operational risk. The type-4 full-converter WTGs have faster dynamics compared to conventional synchronous generators and can help in improving the transient stability limits. The detailed explanation of the positive slopes in the equi-risk contour plots is presented in Chapter 6. It can be inferred that probabilistic risk-based dynamic security assessment can provide useful and critical information on system reliability.

Figure 5.9 shows the equal risk contours for each zone separately. From Figure 5.9 it can be seen that Zone 1 is the lowest risk zone while Zone 4 is the highest risk zone. In the test system T1, Zone 1 is a generation rich zone while Zone 4 is generation deficit region and obtains most of its power through critical tie lines. Hence, any contingency on the critical tie lines serving Zone 4 can cause significant transient stability problems in the region and affect the reliability. The zonal risk contours can help system planners identify critical zones within the system easily and set the reliability criterion. Safe operating limits for a particular zone can be easily identified using this risk assessment technique. The equal risk contours can provide clear information on the bases on which security decisions are made. The zonal risk contours show that converter-interfaced renewable generation helps in lowering risk of load loss, as indicated by the positive slopes of the equi-risk contours in all five zones.

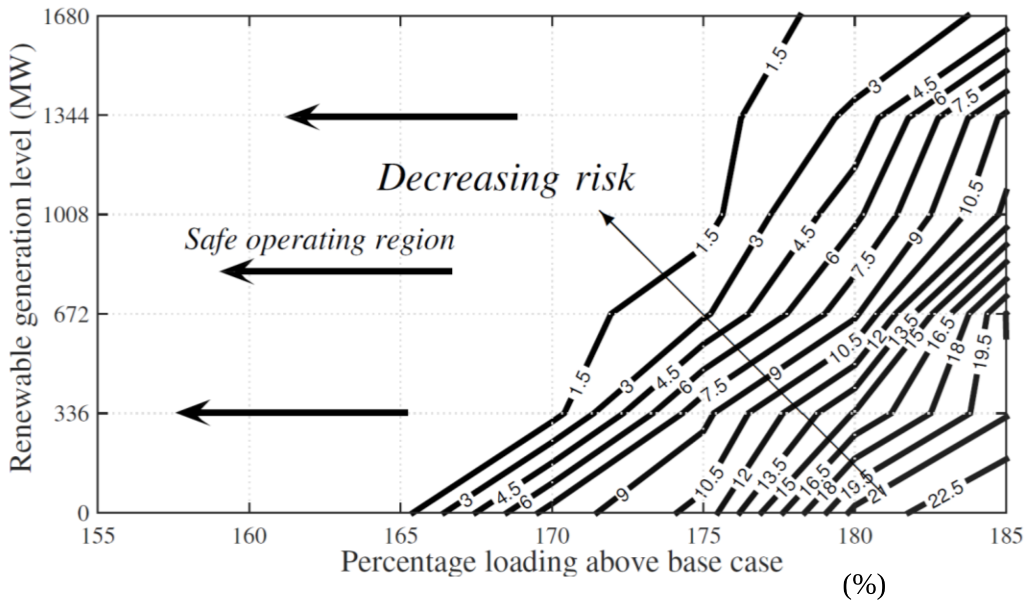


Figure 5.8 System-wide equal risk contours in terms of risk metric ρ in MW

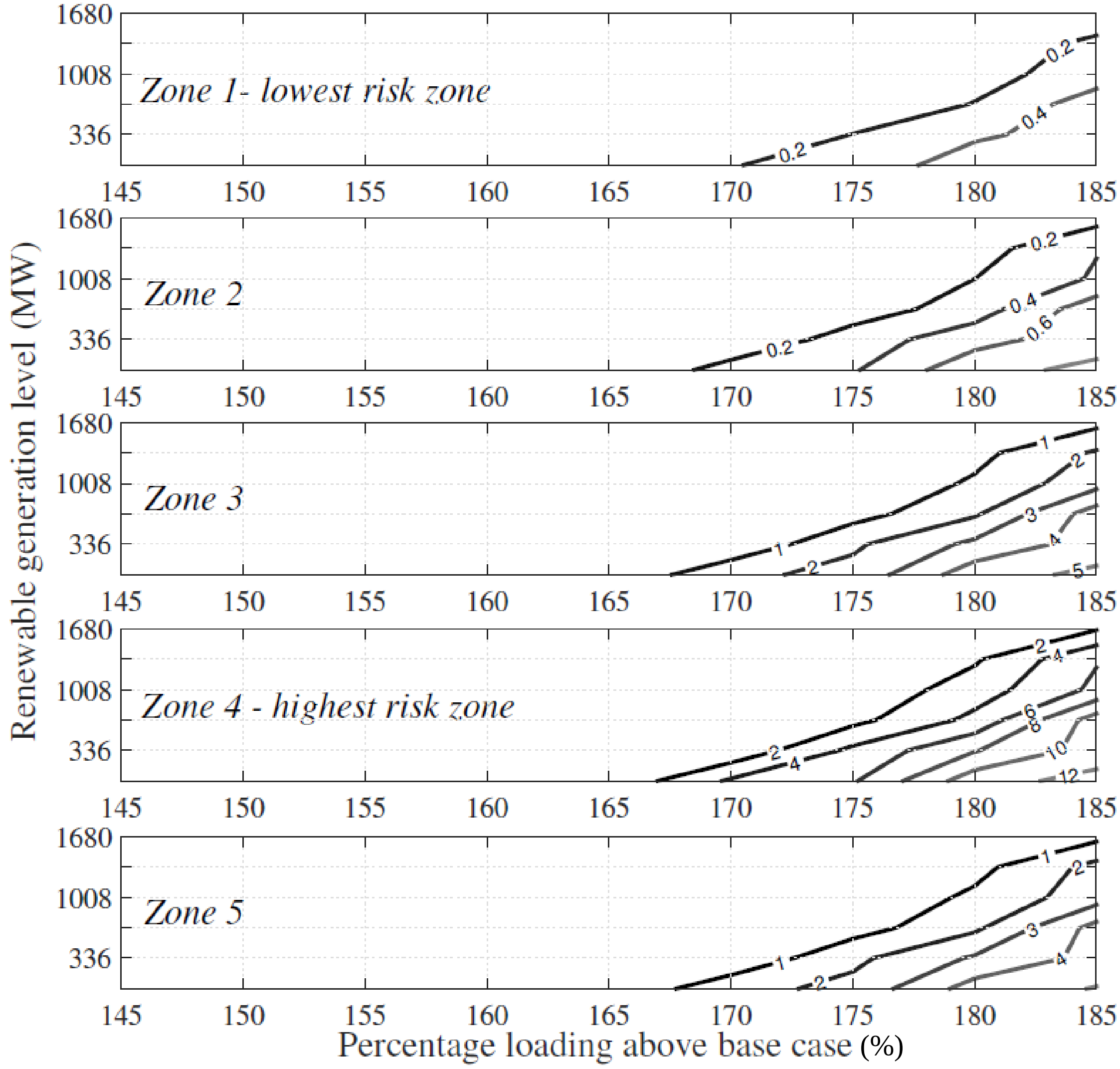


Figure 5.9 Zonal equal risk contours in terms of risk metric ρ in MW

5.7.2. Risk estimation using stochastic wind generation model

In this section, the risk estimation using the stochastic wind generation model is presented. Wind energy like most other renewable generation sources is uncertain in nature. In traditional deterministic reliability assessment, the variability and the intermittency of the wind power generation are not modeled. In the future electricity grid with high penetration of renewable energy, the stochastic nature of such renewable energy sources should be incorporated in the reliability assessment studies. Figure 5.10 shows the calculated risk metric ρ at different wind generation levels and the risk estimated using the stochastic wind generation model. A fitted cumulative density function generated from a typical wind farm historical data as shown in Figure 3.2 is used to obtain the probability distribution at different wind generation levels. It can be seen from Figure 5.10 that the risk estimations at different wind generation levels integrate into the equivalent overall system risk estimated as shown by the dotted line. It should be noted that the risk estimated using the stochastic model is given by (3.10) and can be defined as the sum of the operational risk metric ρ at different renewable generation levels weighted by the probabilities of wind generation level ($Pr(P_{WTG})$) [40, 41]. The figure also shows that as the converter-interfaced wind generation is increased, the operational risk metric ρ is reduced. The stochastic wind generation model can provide an estimate of the overall system risk when an accurate forecast of wind generation is not available. In instances, where accurate knowledge of wind generation information is available, the risk estimation using the exact wind generation level can be used. It should also be noted that a higher wind generation level results in lower operational risk ρ.

Table 5.8 provides a further illustration and quantification of the effect of wind generation on the operational risk metric. From Table 5.8, it can be observed that the risk metric values are provided for the no wind generation case, 100% wind capacity generation level and for the risk metric considering the stochastic wind generation model. The mean risk relaxation for the case with 100% wind capacity generation is 90.9% from the no wind generation case. The mean risk relaxation considering stochastic wind generation model is 51.0% which indicates that converter interfaced wind generation is beneficial to the system in reducing the risk of transient stability events even after incorporating the uncertainty of wind generation.

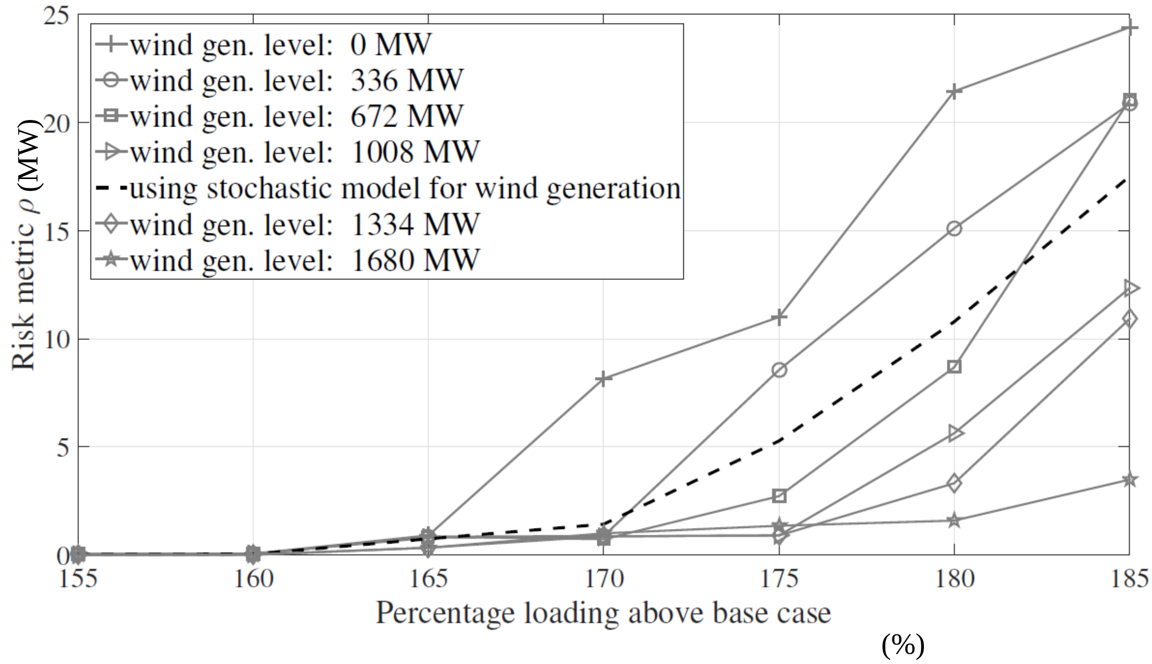


Figure 5.10 Risk estimation using stochastic wind generation model

Table 5.8 Effect of wind generation and uncertainty on risk metric

Loading above base case (%)	**Risk metric ρ (MW)**		
	0 MW wind	**1680 MW wind**	**Uncertain wind**
145	0.0160	0.0000	0.0013
150	0.0492	0.0000	0.0143
155	0.0389	0.0000	0.0272
160	0.0525	0.0000	0.0340
165	0.8843	0.3188	0.7283
170	8.1238	0.9843	1.4064
175	10.9622	1.3254	5.2474
180	21.3771	1.5633	10.7489
185	24.3298	3.4559	17.4492
Mean risk relaxation due to wind generation		90.9%	51.0%

5.7.3. Effect of seasonal variations and load uncertainty on risk assessment

The wind power generation levels usually vary with seasons and hence can have a significant effect on the security of the system. To illustrate the effect of seasonal wind power generation variations on RBSA, two distinct wind power distribution curves are obtained for summer and winter months as seen in Figure 5.11. The probability distributions show that the percentage wind power generation is more in summer months compared to winter months and the effect can be seen in the risk calculations in Figure 5.12. In summer months, higher wind power generation results in lowered risk due to loss of load. Hence, RBSA can be used effectively in incorporating the effect of seasonal variations in the renewable generation in system planning [40, 41].

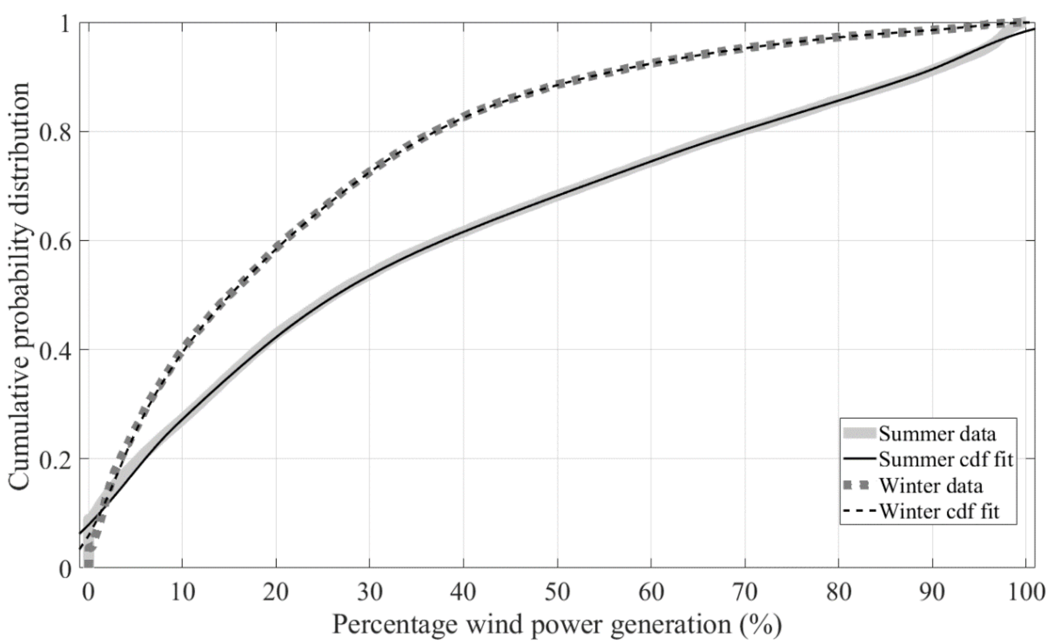


Figure 5.11 Seasonal variation in wind generation probability distribution

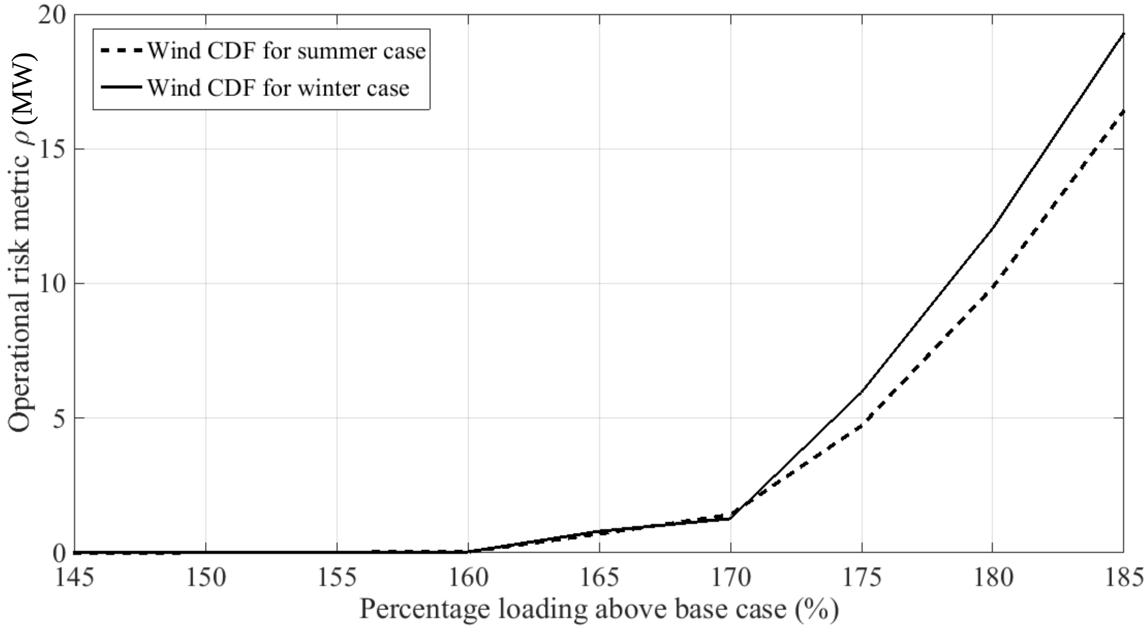


Figure 5.12 Effect of seasonal variation in wind power generation on risk assessment

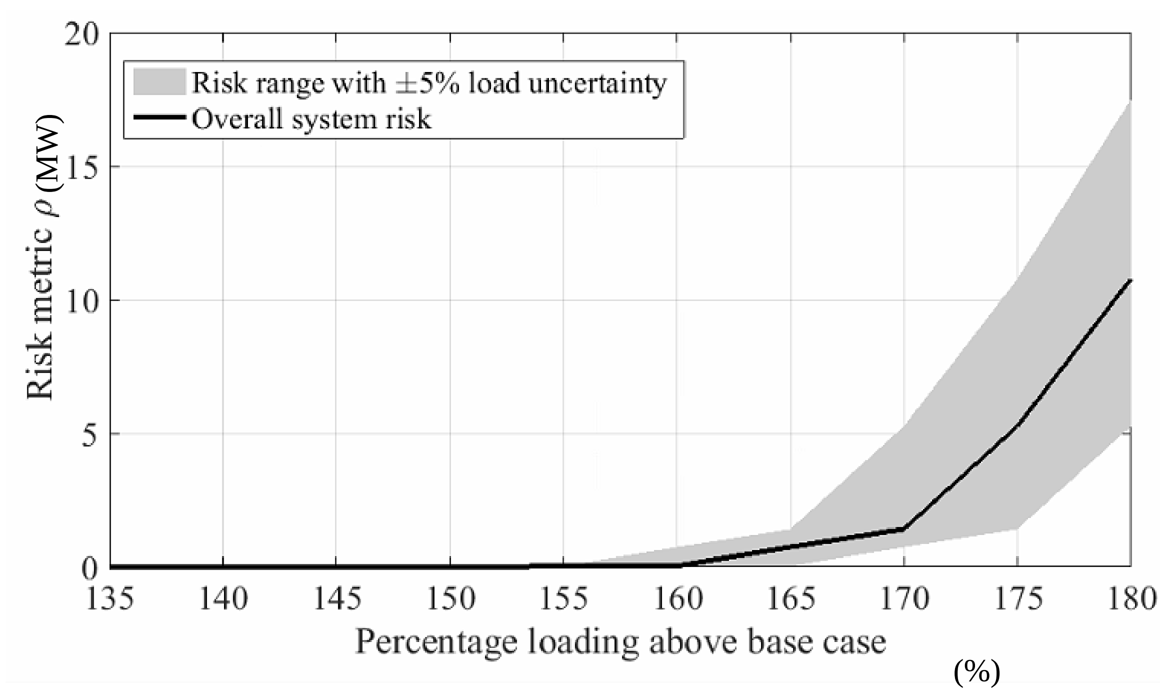


Figure 5.13 Effect of load uncertainty on risk assessment

The risk assessment has been performed at different loading levels using a stochastic model for wind generation. However, considering a load uncertainty of ±5% of base case loading, a risk range/band can be obtained as shown in Figure 5.13. This result can be useful in instances when accurate load forecasts are not available. From Figure 5.13 it can be observed that the width of the risk band increases as the system stress level is increased with increased loading.

5.7.4. Risk-based security limits

Figure 5.14 shows the risk estimated using the stochastic wind generation profile for the individual contingencies. The contingency with the largest mean value of risk over the system loading range is defined as the highest risk contingency which is contingency #6 (fault on line # 9-13) for the test system T1. As a comparison, the deterministic "*N*-1" security criterion is assessed by progressively increasing the loading of the system from base case and running three-phase fault time domain simulations for all credible contingencies.

Table 5.9 shows the simulation summary for the test system T1 consisting of the number of simulations at the different loading levels requiring corrective load shedding and the corresponding risk metric ρ. It can be observed that at 140% above base case, none of the disturbances result in corrective load shedding and the risk metric ρ is zero. At 145% loading, there are 3 cases where corrective load shedding (1%—10% of the loading level) is required, but the risk metric ρ is still very low. As the loading level is increased further, the risk metric ρ increases by small magnitude until the 160% above base case loading level where, a large number of corrective load shedding actions are required, rendering the risk metric ρ to increase significantly [40, 41].

Table 5.9 Simulation summary of corrective load shedding (LS) and risk metric for different loading scenarios

Loading level (%)	Number of simulations requiring corrective load shedding (LS)				Risk metric ρ (MW)
	0%	**1-10%**	**11-40%**	**>40%**	
140	1248	0	0	0	0
145	1245	3	0	0	0.0013
150	1242	6	0	0	0.0147
155	1239	9	0	0	0.0278
160	1233	15	0	0	0.0348
165	1155	92	1	0	0.7419
170	1143	75	12	18	1.4209
175	1110	64	18	53	5.2692
180	1031	68	27	122	10.7867
185	963	56	22	207	17.5038

The NERC deterministic "*N*-1" criterion [1] states that no generator can go out of step and no load should be tripped following a single contingency. From the simulation results, it can be observed that the system has sufficient margin to withstand the tripping of a generator without any instance of corrective load shedding at 140% loading, providing an additional 7% security margin from the deterministic criterion. Between 133% and 140% loading, a contingency will result in generators pulling out of synchronism and being tripped — but will not require corrective load shedding and hence has a computed risk metric ρ of zero. The constraint of 'no generators to be tripped' provides a limit on loading level and does not allow the system to utilize its capability to withstand generator tripping following a fault. Above 140%, there is a probability but not a certainty, that a contingency will result in corrective load shedding. Thus, setting a loading limit using deterministic criterion will lead to a lower limit than with the use of the risk criterion. The first instances of load shedding occur at 145% loading level and the system incurs a very low value of operational risk (ρ = 0.0013). In this report, it is proposed that the security limits can be relaxed using the operational risk metric ρ. Figure 5.15 shows the plot of the operational risk metric ρ on a logarithmic scale. It is to be noted that the security limits could be further relaxed above 140% loading while maintaining the risk metric ρ at a significantly low value and with minimal corrective load shedding. The risk-based approach provides a clear visualization of the sensitivity of operational decision on the system risk.

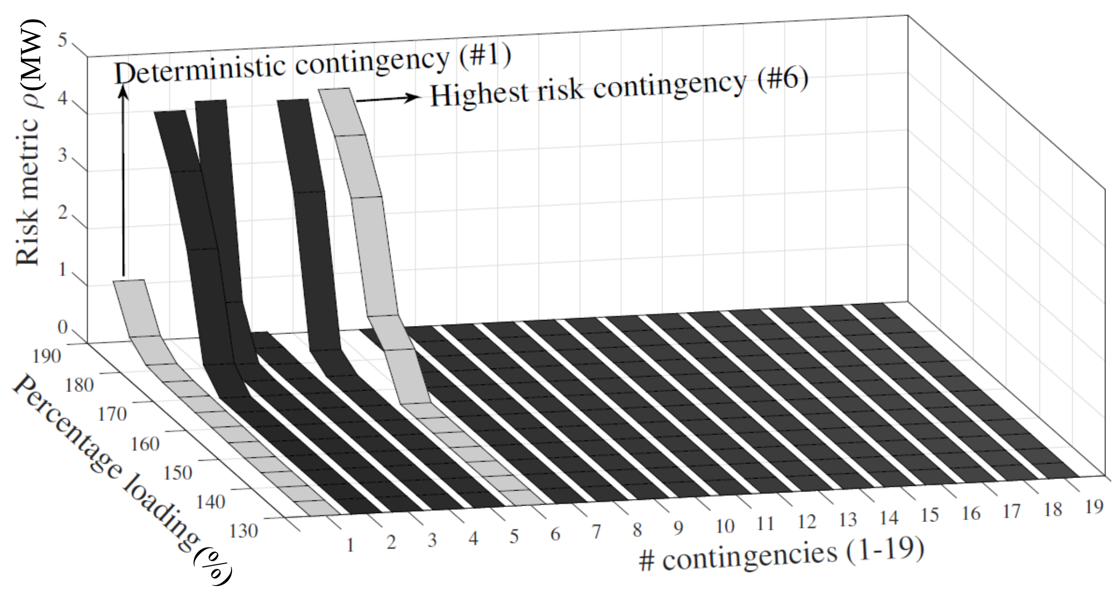


Figure 5.14 Risk metric ρ for individual contingencies at varying loading levels

Figure 5.15 shows the "*N*-1" security margins for deterministic and risk-based transient instability assessment for transient stability. The deterministic approach gives conservative results which result in lower security limits. On the other hand, risk-based security assessment provides higher operating limits based on both the likelihood as well as the consequence of instability. It can also be observed that the overall risk of the system is very low at both the risk-based security limit and deterministic security limits. The comparison shows how the risk-based security criterion provides non-conservative security limits and does provide relevant information about the actual risk of operation at that limit [40, 41].

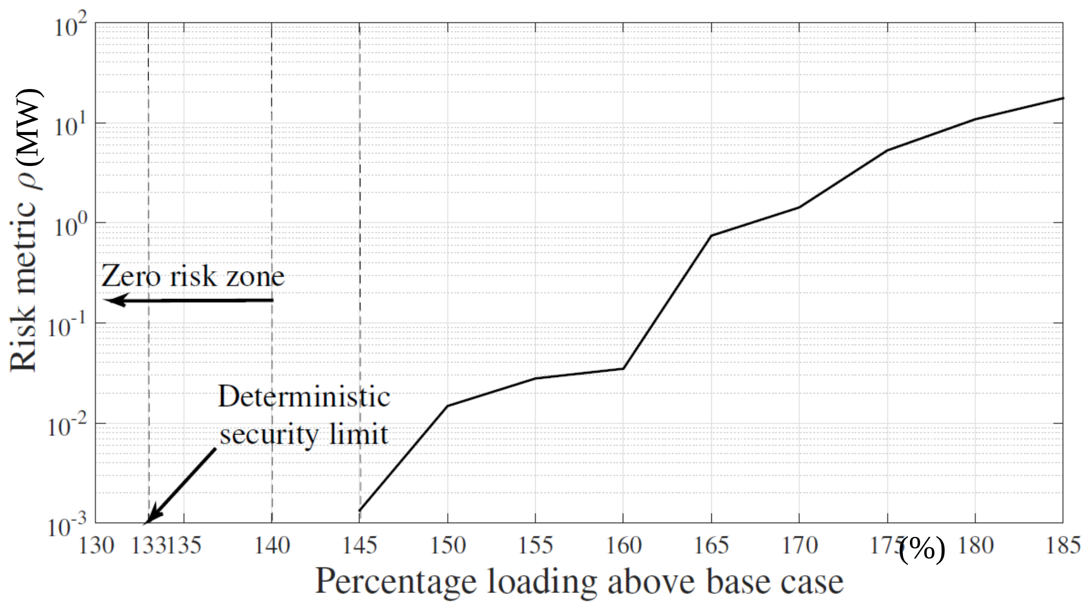


Figure 5.15 Comparison of deterministic and RBSA limits

5.8 RBSA for future grid with very high renewable penetration

In this experiment, the synchronous generators present in the test system are gradually replaced by converter-based renewable generation (type-4 WTG). The total generation capacity is not changed in the system. The MVA ratings of the generators are adjusted according to the percentage of converter based generation. The renewable penetration is varied from 0% to 80% in steps of 20%. Figure 5.16 shows the system overall risk for varying renewable penetration and at four different loading levels. It can be seen that with higher renewable penetration the risk on the system due to the transient stability event is reduced. Hence, with respect to system dynamics and transient stability, high converter-based generation is beneficial for the system considered. The variability and intermittency of such generation sources have not been considered in this study.

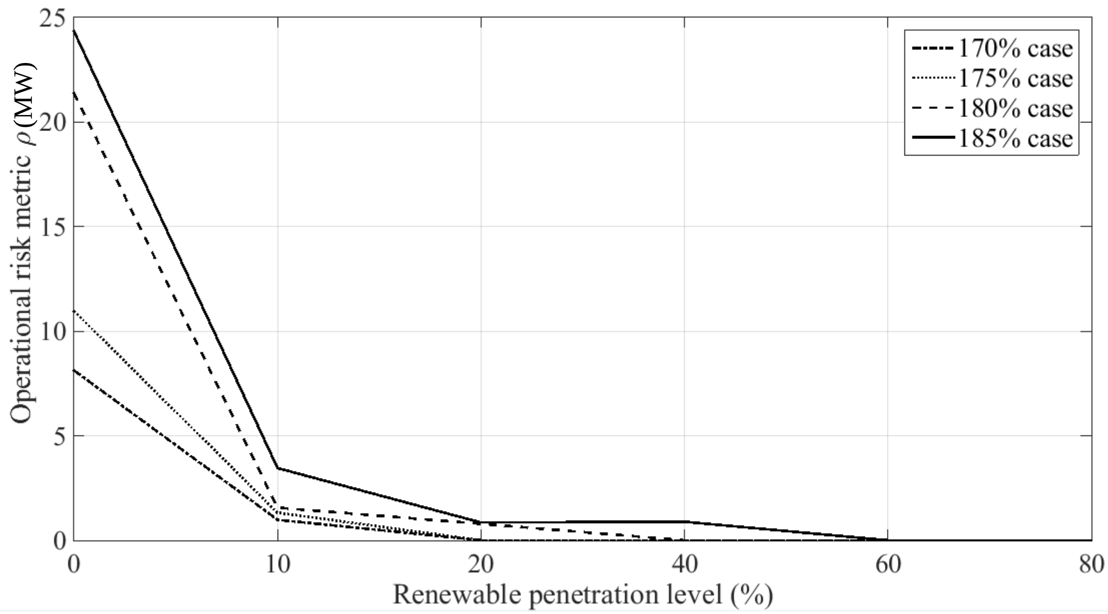


Figure 5.16 Risk estimation for the test system with very high renewable penetration

5.9 RBSA with wind and solar photovoltaic generation

In this study, a test system T2 is used to perform RBSA with wind generation and utility scale solar generation. The test system T2 is a reduced system model of the Western Electricity Coordinating Council (WECC) system used in the industry for stability studies. Figure 5.17 shows the single line diagram of the test system along with the demarcation for the 3 distinct zones.

Table 5.10 Test system T2 summary

Buses	188
Generators	34 (synchronous) + WTG + solar PV
Lines	103
Total synchronous generation	139200 MW installed capacity
Wind generation	24456 MW installed capacity
Solar PV generation	11157 MW installed capacity

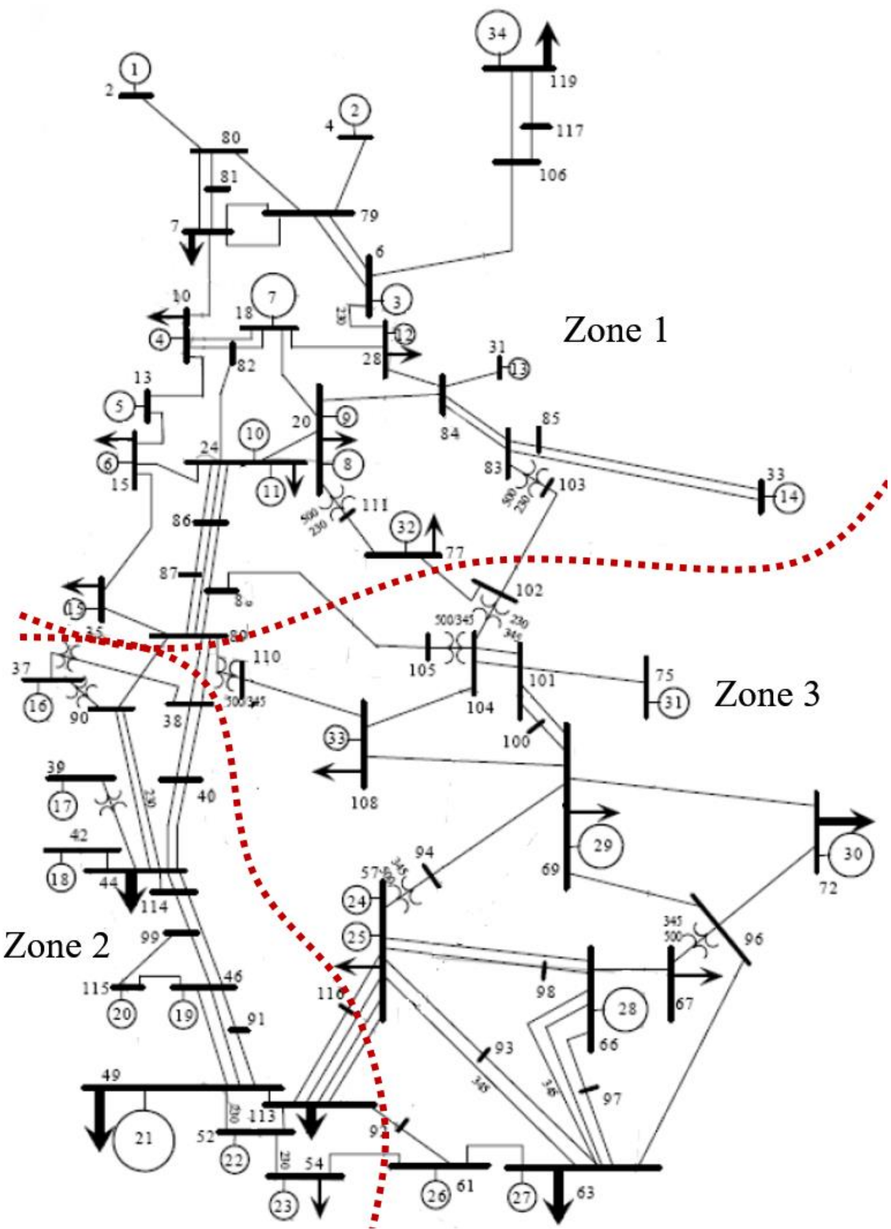


Figure 5.17 Test system T2: reduced WECC model

The system consists of 34 conventional synchronous generators with detailed generator, governor and exciter models. The total installed capacity of conventional generation (139,200 MW). The dynamics of the synchronous machines are modelled in detail with governors and exciters. Renewable generation in the form of type-4 WTG is added at different locations within the test system with installed capacity of 24,456 MW (21.4% of system load) and solar PV generation 11,157 MW (9.8% of system load). All WTG and solar PV are modelled using the GE generic models available in PSLF software. Table 5.11 provides the zone wise details of the renewable generators in the test system T2. The data for the solar and wind penetration level are obtained from the US Energy Information Administration website [57].

Table 5.11 Test system T2 renewable generation installed capacity

Zone 1		**Zone 2**		**Zone 3**		**System total**	
WTG	PV	WTG	PV	WTG	PV	WTG	PV
11548 MW	275 MW	4540 MW	6758 MW	8368 MW	4124 MW	24456 MW	11157 MW

The protection systems are modeled as discussed in chapter 4. The OOS tripping relays are placed on selected transmission lines based on the electrical center detection algorithm discussed in chapter 4, section 4.2.2 and the OOS tripping relay settings are provided in appendix E. The summary of the OOS trip operations for different contingencies is also provided in appendix E.

5.9.1. Operating scenarios for test system T2

In this study, a summer high loading scenario is selected as the base case with total system loading of 114,175 MW and 15% system reserve level. A grid of power flow scenarios is generated by varying the wind generation and solar PV generation independently from 0% to 100% installed capacity in steps of 12.5%. For each of the operating point, positive sequence time domain simulations are performed for transmission line '*N*-1' contingencies for different fault types and fault locations. The simulation results are discussed in the following section.

5.9.2. Test system T2 simulation results

Figure 5.18 shows the mesh plot for the risk assessment of the test system T2 for varying wind and solar penetration. The plot shows that the operational risk metric ρ is maximum for the operating scenario with zero wind and solar PV generation and the risk metric ρ value reduces as the penetration level of wind and solar generation is increased. This result also aligns with the results from test system T1 showing that converter-interfaced generation is beneficial to the electricity grid for stabilizing transient instability events. '*N*-1-1' contingency analysis is a crucial part of transmission planning studies especially for large interconnected systems like the WECC system. In the next experiment, a critical tie-line (#line 89-38) carrying power from zone 1 to zone 2 is tripped at pre-fault to perform a '*N*-1-1' RBSA study. Tripping a critical tie-line results is a stressed system which is more vulnerable to further transient events as the power flows on the other lines carrying power from area 1 to area 2 are increased. The RBSA is performed with the new pre-fault operating point and the mesh plot of the simulation is shown in figure 5.19. From the figure, although the risk metric ρ values are higher than the previous case but higher penetration levels of converter-interfaced generation results in lower risk. The plots from the case with and without the pre-contingency line trip are superimposed on the same graph in Figure 5.20 and the effect of the stressed condition on the system risk metric can be visually identified. Similarly, other '*N*-1-1' events can be studied using the RBSA methodology and system planners can analyze system risk visually for different operating scenarios and can also obtain a sensitivity of the system risk to renewable penetration level. It is to be noted that the risk reduction due to higher solar or wind generation level is based on the assumption that the renewable generation is considered to be a certainty. If a stochastic model for wind and solar is incorporated the mean risk relaxation will be less.

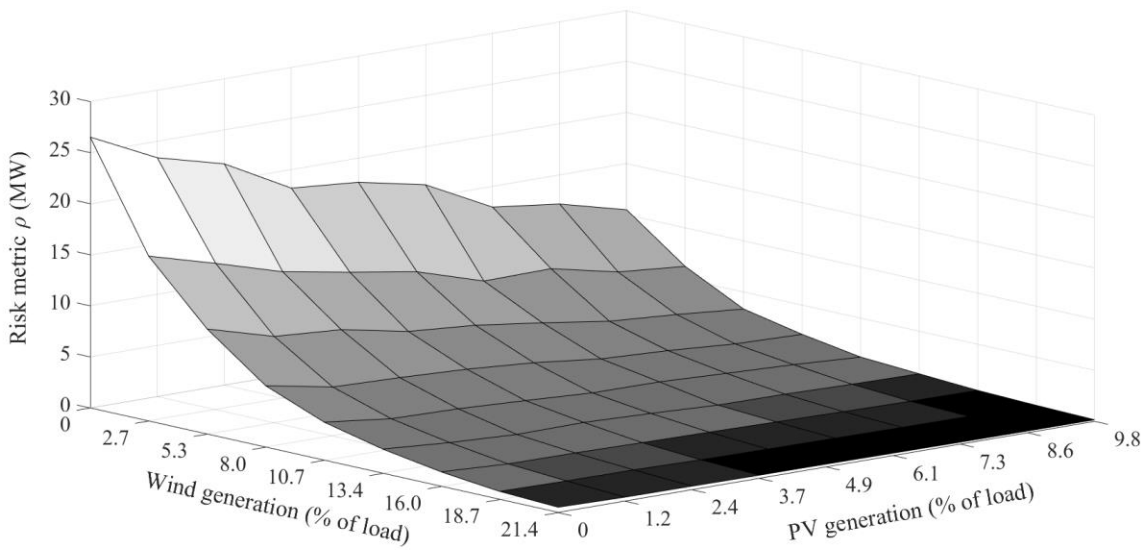


Figure 5.18 Risk metric ρ of the system T2 base case for varying PV and wind power generation

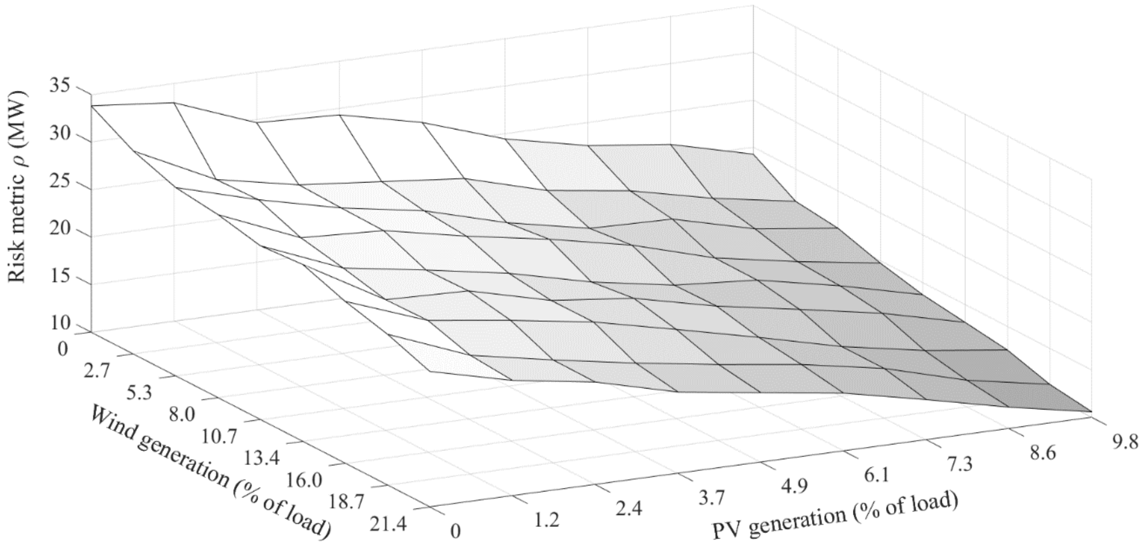


Figure 5.19 Risk metric ρ of the system T2 with line #80-38 tripped at pre-fault

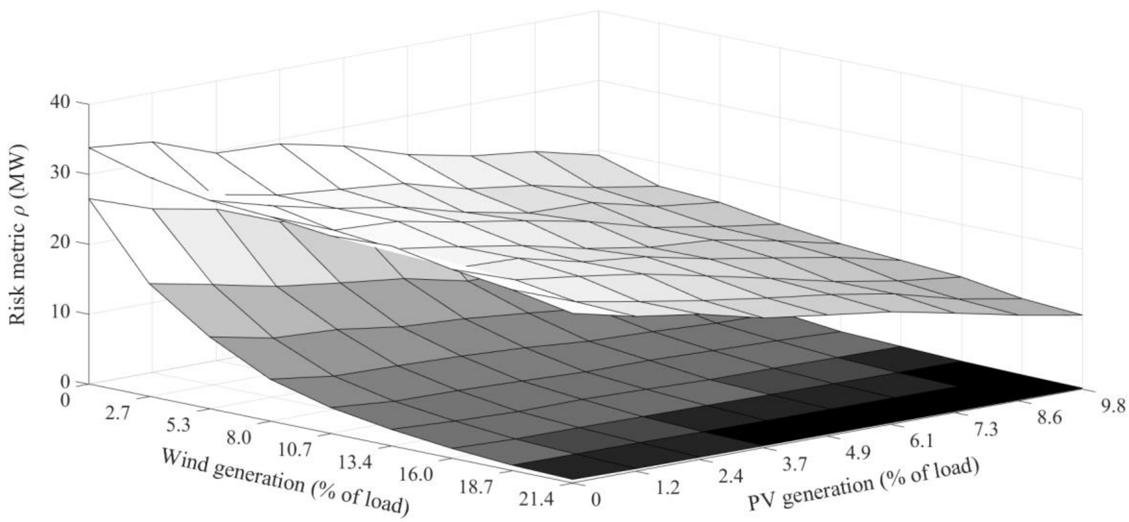


Figure 5.20 Comparison of risk metric ρ of the system T2 with and without line #80-38 tripped at pre-fault

5.10 Summary

In this chapter, the RBSA simulations results have been discussed. The CPU time metrics are presented in Appendix B to provide an understanding of the scalability of the proposed methodology. Details of the steady state and dynamic model parameters are provided in Appendix C and Appendix D respectively. The OOS relay settings for the test case T2 are provided in Appendix E. The summary of the OOS relay tripping operations for different contingencies at a selected operating condition are also provided in Appendix E. The PSLF EPCL codes and the MATLAB risk estimation codes are provided Appendix F and Appendix G respectively. In the following chapter, the analytical explanations of the simulation results are presented using a simple single machine test case.

Chapter 6

ANALYTICAL EXPLANATION OF RBSA RESULTS

6.1 Simple test case (T3)

In chapter 5, the positive slopes in the equi-risk contour plots (Figure 5.8 and Figure 5.9) show that converter-interfaced renewable generation has a significant impact on system risk. To illustrate the above phenomenon, a simple test system (T3) is considered as shown in Figure 6.1. T3 consists of a synchronous generator at bus #1 and a type-4 WTG at bus #1’ connected to a 230 kV transmission system (two transmission lines).

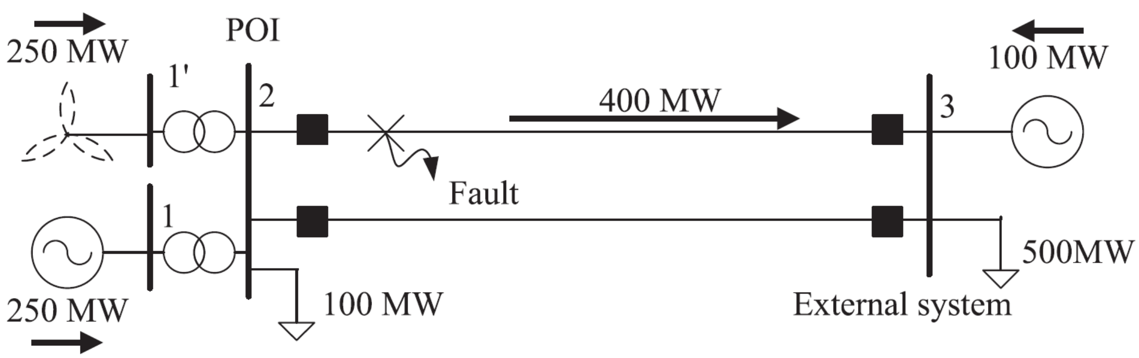


Figure 6.1 Simple test system (T3)

The synchronous machine is modeled using a detailed positive sequence model with exciter and governor and the WTG is modeled as a generic GE WTG full-converter model [51]. There is a local constant impedance load of 100 MW at bus #2. Two 230 kV transmission lines are present between bus #2 and bus #3. Bus #3 is modeled as the infinite bus with a constant impedance load of 500 MW. To maintain the generation-load balance, 100 MW is imported from the external system to feed the local load. Hence, for normal operation, the tie line flow is 400 MW. Different cases are considered by varying the ratio of the synchronous machine and the WTG MVA capacity. A three-phase fault is simulated near bus #2 at time t = 1 s and cleared after 5 cycles by removing the faulted line. Figure 6.2 shows the active power flow in the line #2-3 and Figure 6.3 shows the voltage at the point of interconnection (POI) for all the different cases considered obtained using positive sequence time domain simulation in PSLF software.

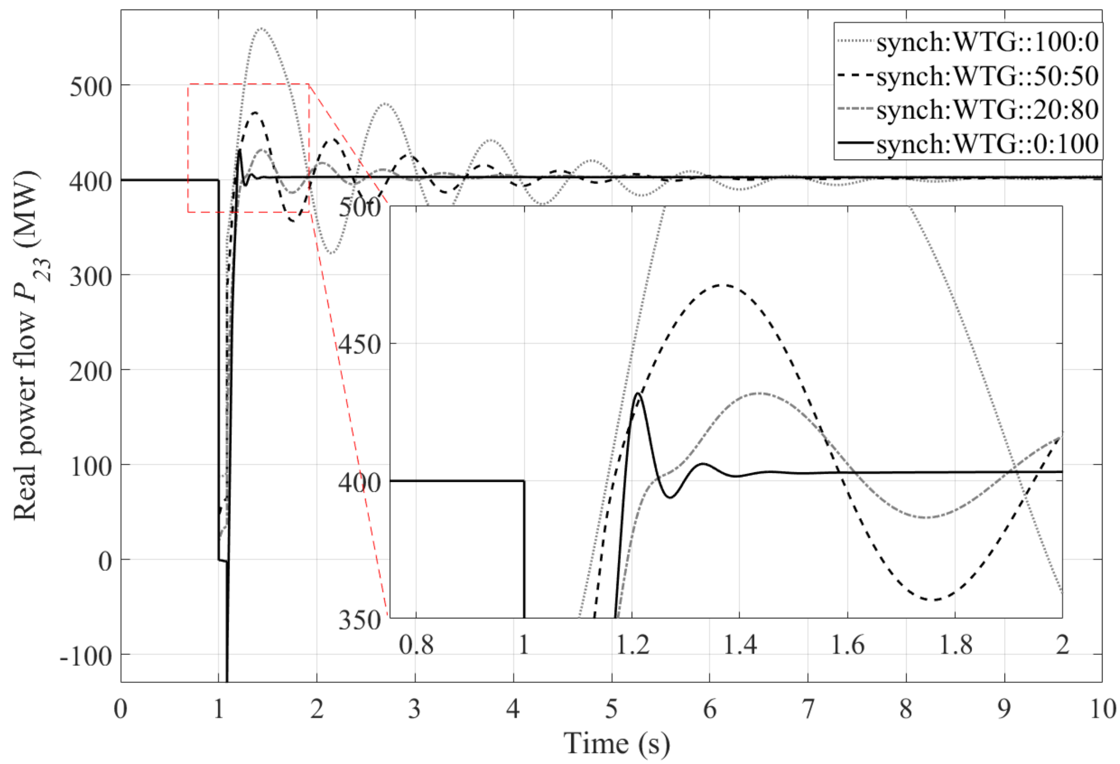


Figure 6.2 Active power flow at the POI for the test system T3

From Figure 6.2 it can be seen that as the converter-interfaced penetration is increased, oscillations on the active power transfer are reduced, with faster settling time. It can be observed from Figure 6.3 that higher converter-interfaced penetration results in faster voltage recovery and reduced voltage dip at the POI. The faster settling of the oscillations in case of higher wind generation level can be explained on the basis of lower decelerating power required to settle to a new operating point. The synchronous machines require large decelerating power and have slower voltage recovery following a fault.

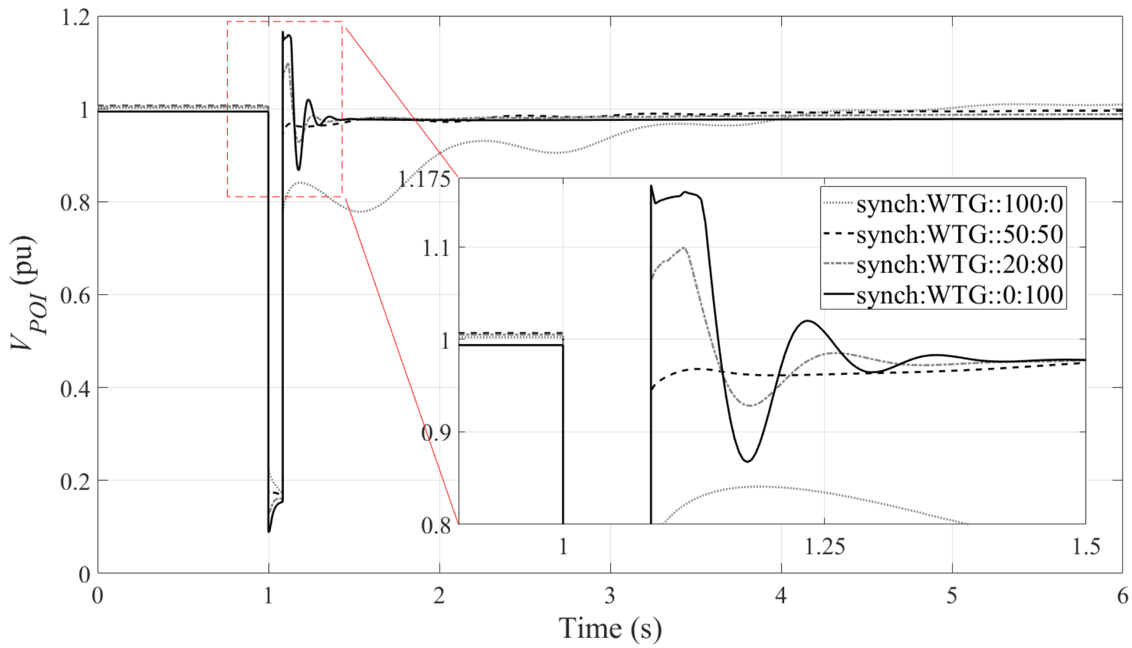


Figure 6.3 Voltage at the POI for the test system T3

6.2 Equal area criterion of the test case (T3)

To analytically describe the effect of renewable generation on transient stability events, the behavior of the full-converter WTG model is approximately represented by a negative load and a STATCOM (to simulate the voltage regulation of type-4 WTG) at the POI. Using the swing equations and the calculated pre-fault, fault and post-fault impedances, the *P*-δ relationships are obtained for the two cases. Figure 6.4a shows the equal area criterion for the 100% synchronous generation case where the critical clearing angle $\delta_{cr} < \pi/2$. Figure 6.4b shows the equal area criterion for the case with 50% synchronous machine with a negative load and a STATCOM. It can be observed that the mechanical power P_{mech} for the synchronous machine has reduced to 0.5 pu as 50% of the generation is represented by negative load. The detailed expression of the P-δ relationship with a STATCOM model is provided in detail in [58]. It can be seen in Figure 6.4b that the $\delta_{cr} > \pi/2$ results in a higher transient stability limit.

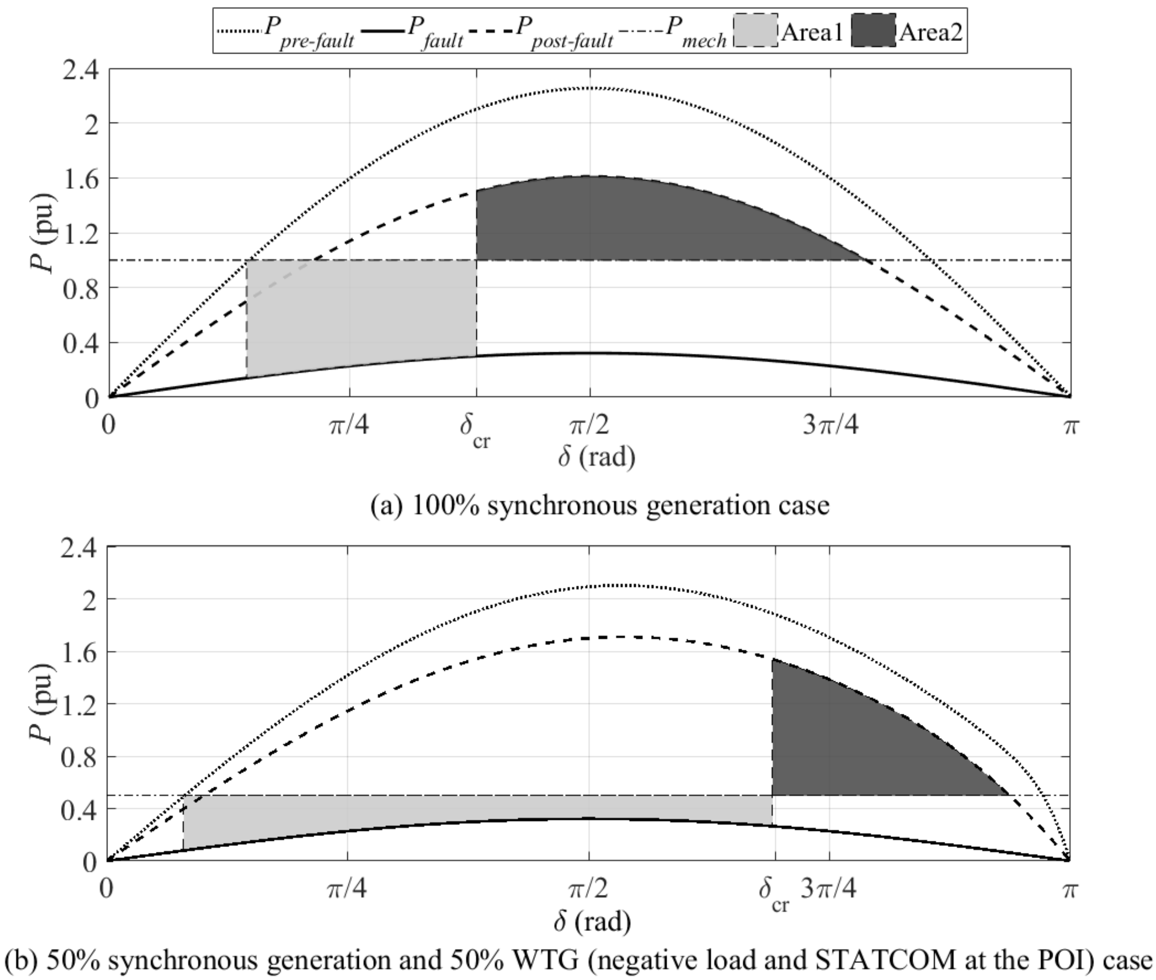


Figure 6.4 Equal area criterion for test system T3

6.3 Summary

The effect of converter interfaced renewable generation on transient stability has been illustrated using a simple test system. The equal area criterion is derived analytically by assuming that a full converter WTG behaves like a negative load and a STATCOM at the POI. The analysis shows that full converter interfaced generation can enhance the transient stability limits. The MATLAB code for plotting the equal area criterion is provided in Appendix H. In the following chapter, the RBSA Contingency Ranking and Diagnostics Tool is presented.

Chapter 7

RBSA CONTINGENCY RANKING AND DIAGNOSTICS TOOL

The RBSA procedure generates a large dataset consisting of time domain simulation data, risk assessment data and contingency ranking data. Representation and visualization of the assessment of this large dataset is critically important in transmission planning and decision making. In this chapter, the RBSA contingency ranking and diagnostics tool is presented. This tool provides a comprehensive user interactive platform to navigate the risk assessment results. The tool is designed using the open source statistical data analytics platform R-Project for Statistical Computing [59] and R-shiny package [60]. The RBSA software including the user interface has been entirely programmed in R as a part of the research work.

7.1 Architecture of the RBSA diagnostics tool

The overall architecture of the tool is illustrated in Figure 7.1. The RBSA background batch process consists of the automated scripts to perform the time domain simulations in GE PSLF for all operating conditions as well as the risk calculations using the probabilistic models. The results of risk calculations as well as the time domain simulations for individual contingencies are stored in spreadsheets to be used by the RBSA diagnostics tool. The RBSA diagnostics tool provides an interactive user interface where the RBSA results and contingency ranking reports can be explored and compared based on specific user inputs. The tool can run on a standalone terminal as well as on a server which can be accessed by multiple users at the same time. Users can select different test systems and scenarios using a single platform. The platform provides fast interactive solution to risk based contingency analysis and does not require repeated execution of time domain simulations or risk assessment calculations to investigate a specific operating condition.

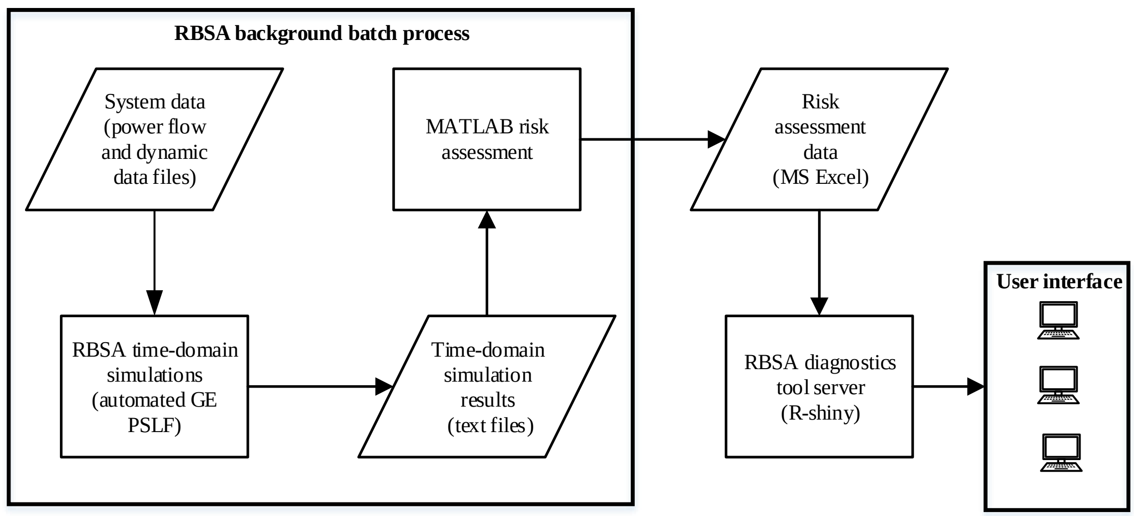


Figure 7.1 RBSA diagnostics tool system architecture

7.2 RBSA diagnostics tool for test system T1

Figure 7.2 shows the screenshot of the RBSA diagnostics tool when the risk assessment data for test case T1 is loaded into the tool. The user can select the loading condition as well as the renewable generation level, the diagnostic tool then displays the risk metric ρ for the selected operating condition on the screen. An interactive mesh plot of the risk metric for different operating points is also displayed. Figure 7.3 shows the screenshot of contingency analysis tab of the RBSA diagnostics tool for the test system T1. This tab displays the contingency ranking based on the operational risk metric ρ and the contingency list including fault rates. Figure 7.4 and 7.5 shows the impact analysis tab of the RBSA diagnostics tool. The impact analysis tab displays the contingencies in the descending order of the risk metric ρ and two boxes for impact assessment results. The impact assessment box provides user selections for contingency number, fault type and fault locations and displays the MW load loss, MW generation loss and fault rate for the selected contingency. The two impact analysis boxes enable the user to compare the two different contingencies simultaneously. This tool can provide the system planner with the information on how the risk metric translates to the actual generation and load loss for an operating condition. In Figure 7.4, at a loading level of 180% and renewable generation of 672 MW the risk metric ρ = 4.32 MW and the actual MW load loss and MW generation loss for a specific fault type and location is displayed along with the fault rate of the transmission line. Hence, an operational risk metric ρ = 4.32 MW can be translated to a deterministic event and its actual effect on the system in terms of MW load loss and MW generation loss can be evaluated. Figure 7.4 shows the case where the highest risk contingency (contingency #6) and the second highest risk contingency (contingency #2) have the same fault rates, hence the resulting risk values are dependent on the impact assessment. Contingency #6 has a higher load loss of 6851 MW compared to 4111 MW for Contingency #2. Hence, the risk metric value is dependent on the impact assessment results for the case 1. In Figure 7.5, contingency #5 has a higher fault rate compared to contingency #2 and results in higher value of risk metric ρ, although the actual MW load loss is lower in the latter case.

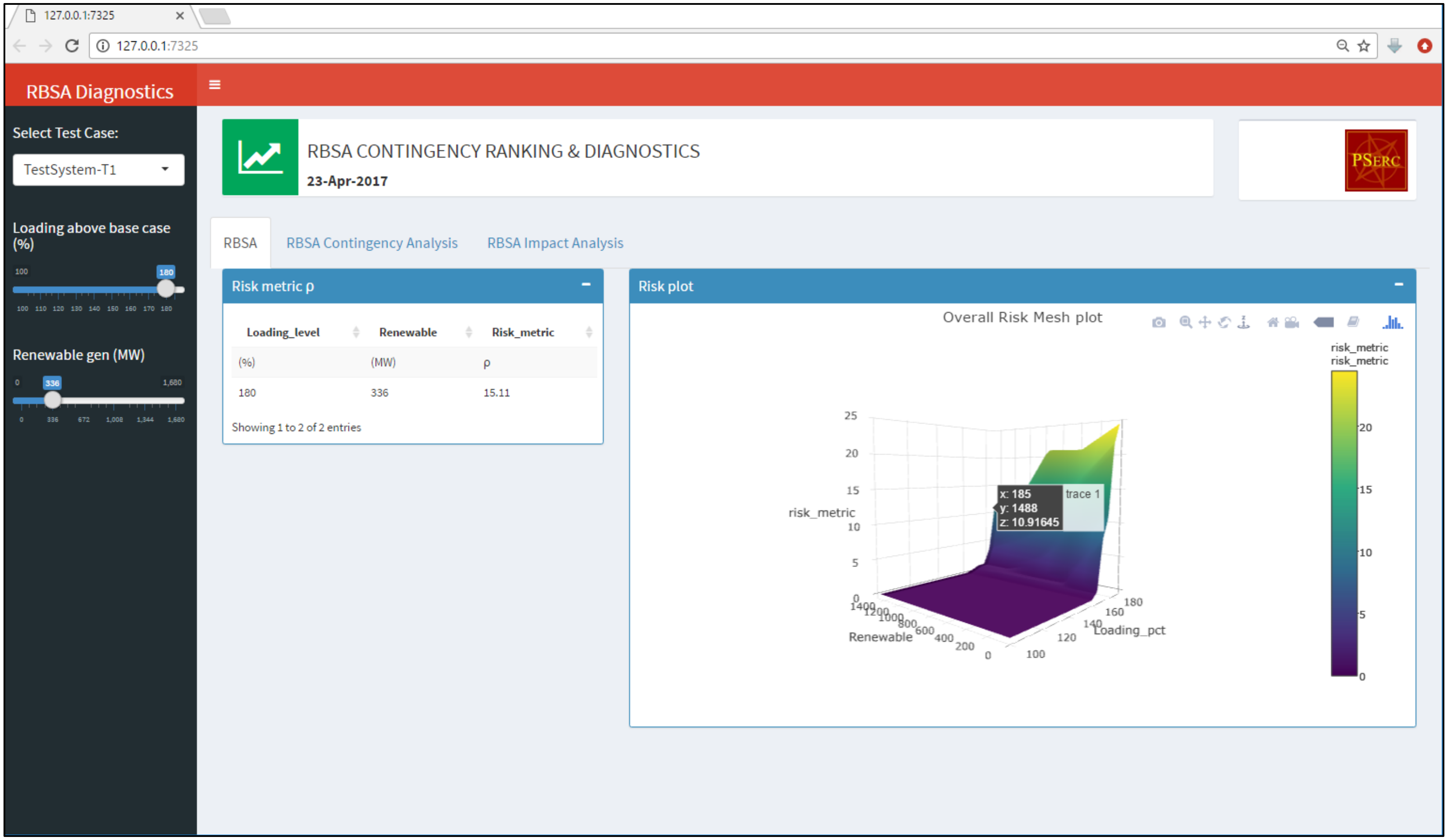


Figure 7.2 RBSA diagnostics tool: overall risk for test system T1

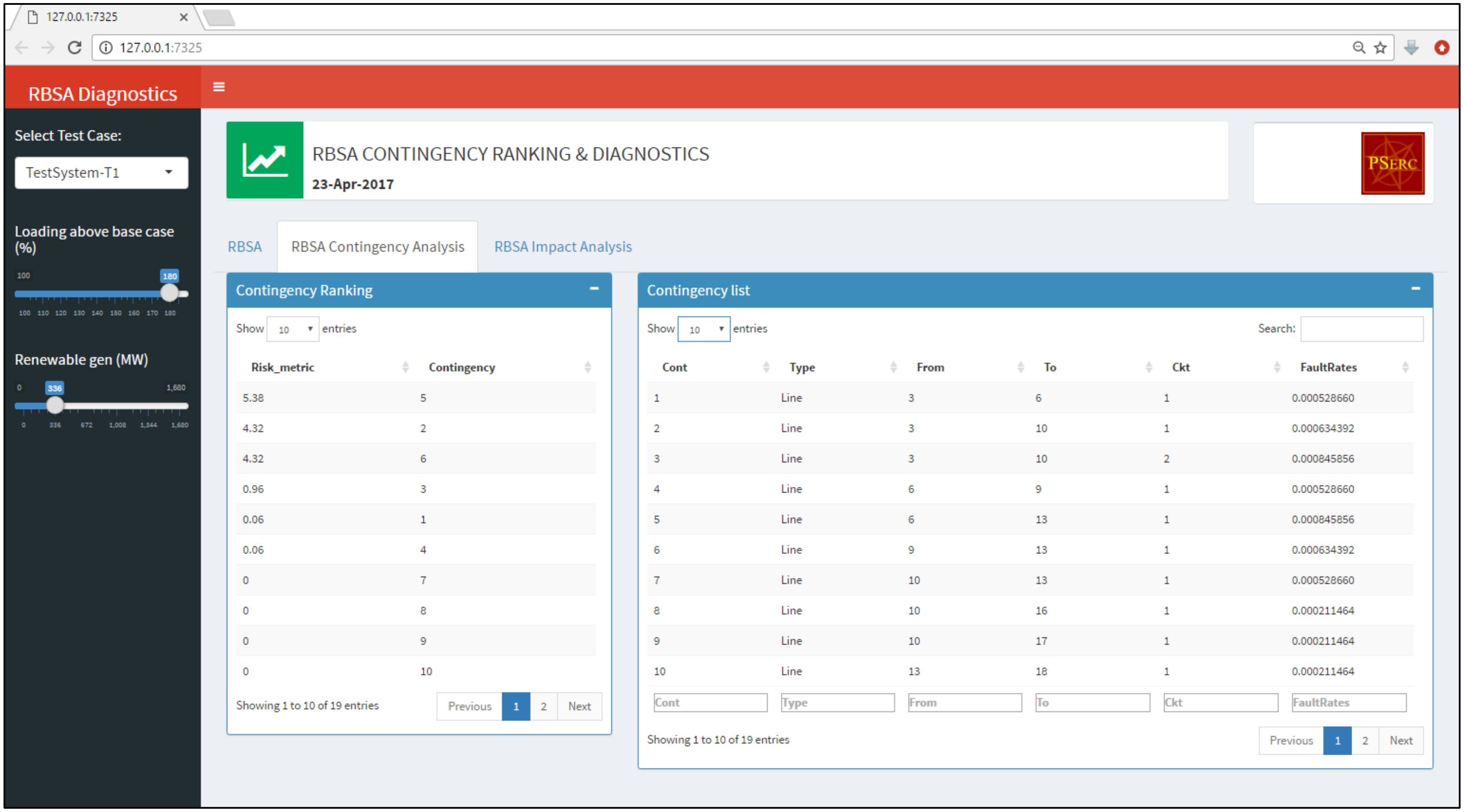


Figure 7.3 RBSA diagnostics tool: contingency ranking for test system T1

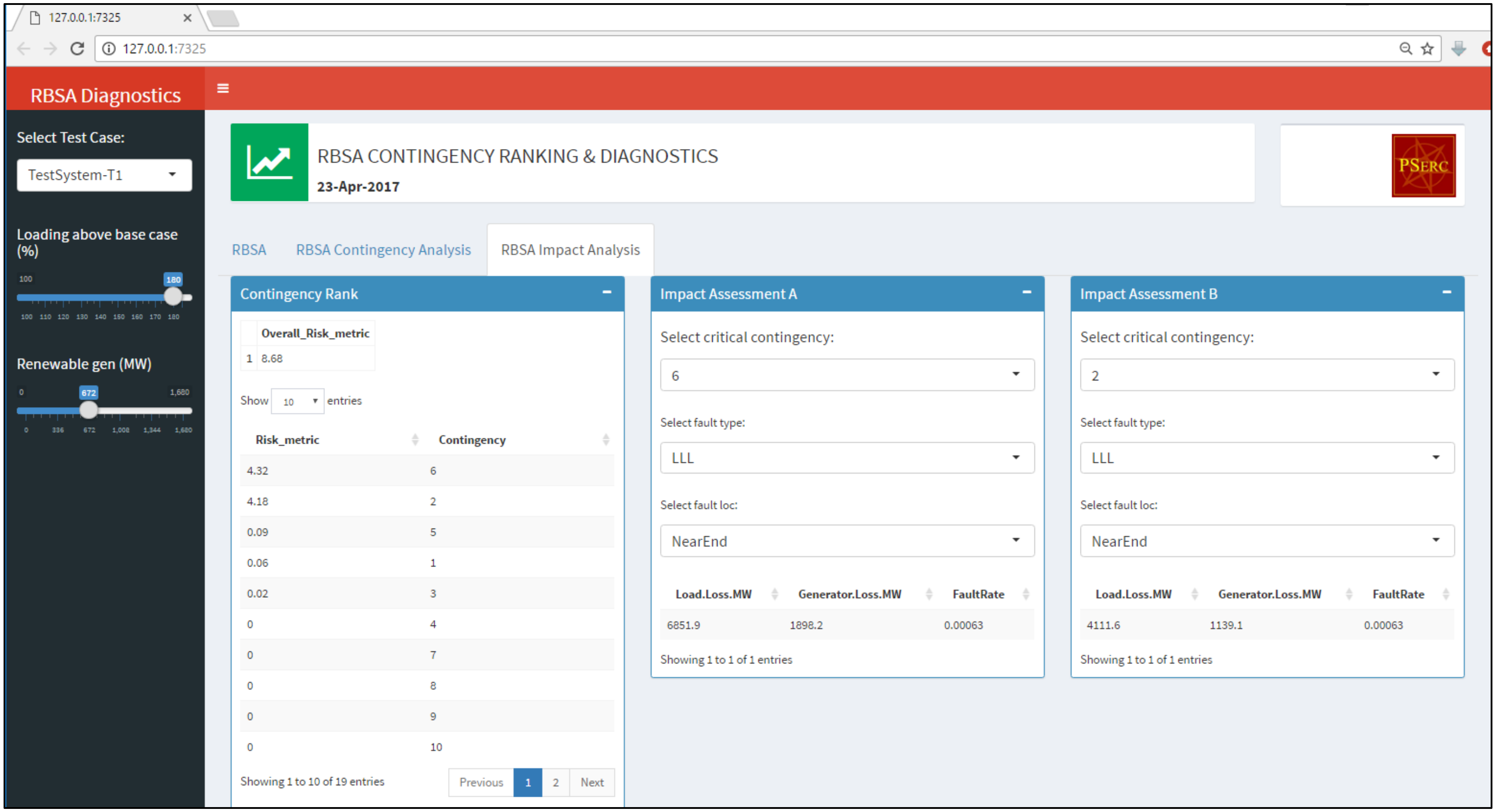


Figure 7.4 RBSA diagnostics tool: impact analysis for test system T1 – case 1

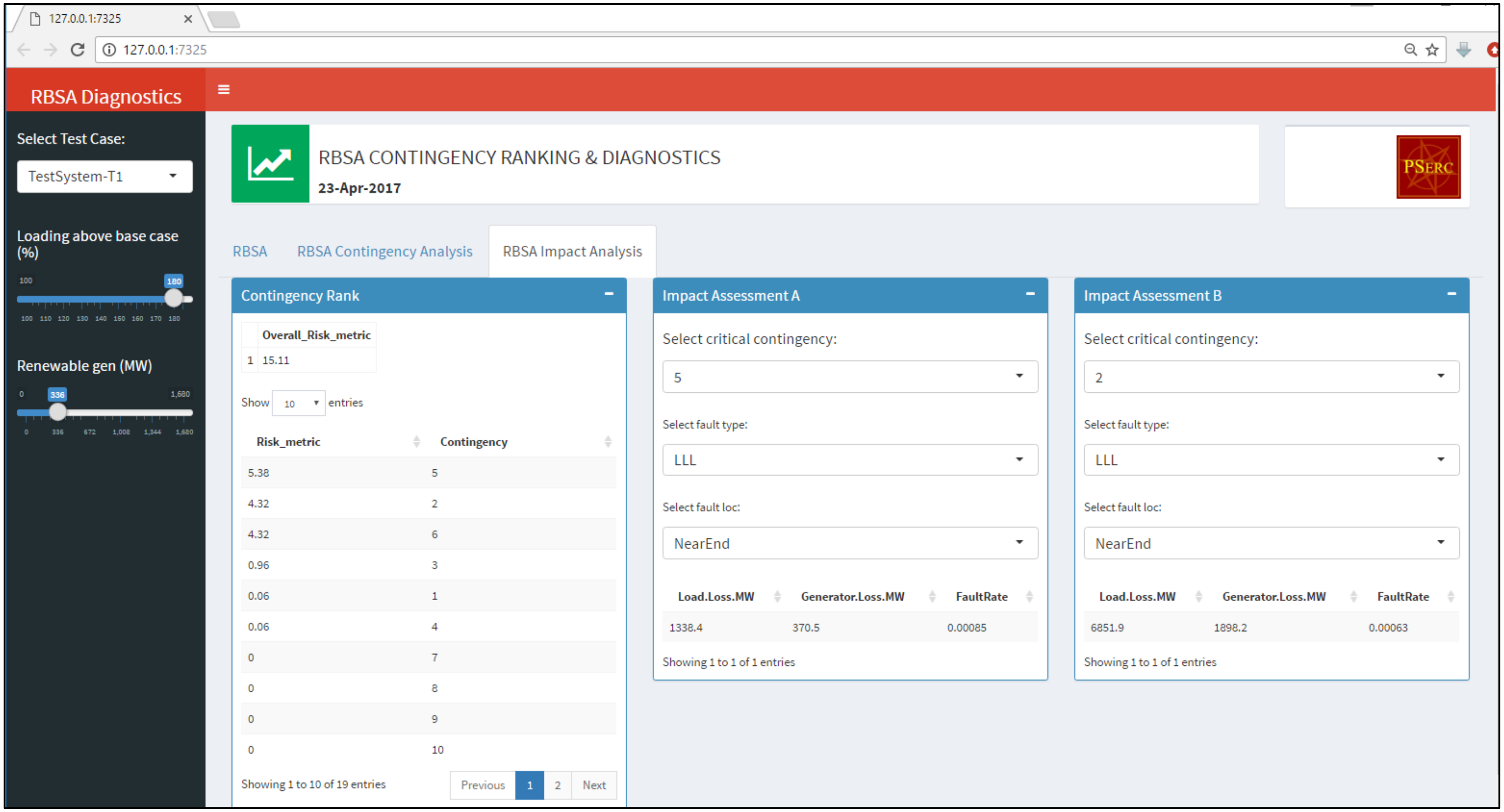


Figure 7.5 RBSA diagnostics tool: impact analysis for test system T1 – case 2

7.3 Summary

In this chapter, a framework for RBSA contingency analysis and diagnostics tool is presented. This diagnostics tools can be beneficial in system planning as users can interpret probabilistic risk metric values to actual load and generation loss for critical contingencies. This tool provides a simple user interface for navigating through the various operating conditions as well as select contingencies without executing time domain simulations or risk calculations, hence providing a fast and robust approach for handling large time domain simulation and risk assessment data. The following chapter presents the conclusions and future work for the research work.

Chapter 8

CONCLUSIONS AND FUTURE WORK

8.1 Conclusions

The traditional deterministic "*N*-1" criterion provides conservative limits and provides inadequate information about the probability of occurrence of the worst-case contingency to make crucial operational decisions. The risk-based method, on the other hand, helps in the quantification of the security criterion, providing an actual risk of a contingency on system security. The utilities, as well as system operators, have a transparent basis on which security limit decisions can be made.

The RBSA can be used in defining new standards for the transient stability of the system. The risk of operating the power system should be evaluated to rank the credible contingencies. Standards should be formulated such that the highest risk contingency is accounted for in the decision-making process for security assessment instead of the traditional worst-case contingency. Current NERC reliability standards are deterministic and do not incorporate any probabilistic methods. As a first step, RBSA can be compared with the current deterministic standards while making security decisions.

Identifying a risk threshold can be critical for a system and is not straight-forward. For the system to be reliable it must operate at very low risk and ideally the system should operate at zero risk. Selecting the risk threshold will require some detailed analyses on the high-risk contingencies that contribute most to the risk estimates. The risk threshold will vary from system to system. One approach may be to select a risk value as the initial threshold and then through detailed analyses of all the critical high-risk contingencies decide whether to increase or decrease the threshold. A few iterations of this technique can be used to set a risk threshold for a system or a particular contingency.

RBSA is used to estimate both overall system risk and risk of individual contingencies. The overall system risk is measured by summing the risk of all the credible contingencies and not by the highest/high-risk contingencies. RBSA helps in identifying the high-risk contingencies that can affect the system reliability. System planners can perform detailed analyses on the high-risk contingencies to make critical security decisions.

The effect of renewable penetration on system reliability can be investigated using RBSA. The equal risk contours can be used by system planners to determine secure operating regions. Zonal risk assessment can help system planners in identifying key areas within the system that can affect system reliability. From the simulation results, it can be seen that converter-based generation helps in reducing the risk due to transient instability due to its faster control and dynamics compared to synchronous generators. A stochastic model for wind generation is also introduced in the risk estimation procedure to incorporate the variability of such sources in the security assessment. The seasonal variations of wind power generation have also been analyzed. The effect of solar PV generation and wind generation in RBSA has been studied on an industry standard test case. Also, the '*N*-1-1' contingency analysis using RBSA has been discussed with the same test case.

The impact of transient instability can be assessed either by a cost based metric or by the proposed parameter independent operational risk metric ρ, the latter being easy to estimate. In systems where risk indices estimated from cost-based metrics are difficult to compare, the risk indices estimated using the operational risk metric ρ provide more insight into such systems.

The risk-based security assessment has a high computational burden due to a large number of time domain simulations involved. However, the disadvantage due to the added computational burden is compensated by the extended operating limits provided by this method. The computational burden is reduced by using different checks and filters to avoid time domain simulations for stable cases.

An interactive robust RBSA diagnostics tool has been developed which can be effectively used to map risk metric parameters to actual MW load loss values and explore the impact of specific contingencies based on specific user inputs. This tool can be used to visualize and analyze large simulation data obtained from time domain simulations.

Hence, RBSA if adapted the major benefit that can be expected is higher system operating limits based on both likelihood and impact of events and not on the worst-case scenario. The RBSA quantifies the sensistivity of uncertain renewable generation on the system risk. With the dynamics of the grid getting altered with addition of more and more renewable generation, RBSA can be effectively used by system planners in maintaining reliability and security of the future electricity grid.

8.2 Future work

The dependence between the loading condition and wind scenario is an important aspect of RBSA for systems with high renewable generation levels and can be considered in detail as a part of the future work.

The computational burden of RBSA is due to large number of time domain simulations involved in the assessment procedure rendering the methodology only useful for planning studies and not operational studies. Computational time can be reduced more than 50% using parallel computing techniques. Most of the power system simulation software are getting equipped with high performance computing algorithms that use multiple CPU cores to execute time domain simulations simultaneously. The applicability of RBSA using high performance computing can be an interesting topic for future studies.

Advanced machine learning algorithms can be used to train the RBSA data for different system operating conditions which can be used in forecasting system vulnerabilities in operations study by identify critical contingencies that might affect the system reliability. With the advancement in data mining and machine learning techniques many data centric approaches using PMU data are being developed to predict power system vulnerabilities. A PMU centric RBSA can also be formulated based on PMU data and transient stability simulation to detect online system risk.

Load at different locations are shed at pre-determined stages based on frequency threshold limits. Different load shedding strategies can affect the impact assessment and hence the risk assessment results. Moreover, the effect of composite load models on system risk can be a examined in the future.

Small signal stability and transient voltage stability phenomenon can be assessed using risk-based methods. In such cases, however, the impact can be assessed by linear/non-linear severity functions of modal damping (for small signal stability) and voltage profile (for transient voltage problems).

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APPENDIX A

FAULT RATES OF THE SELECTED CONTINGENCIES

Table A.1 Fault rates of the selected contingencies (transmission lines)

Cont #	From Bus	To Bus	Ckt	kV	length	fault rate
1	3	6	1	500	250	0.000529
2	3	10	1	500	300	0.000634
3	3	10	2	500	400	0.000846
4	6	9	1	500	250	0.000529
5	6	13	1	500	400	0.000846
6	9	13	1	500	300	0.000634
7	10	13	1	500	250	0.000529
8	10	16	1	500	100	0.000211
9	10	17	1	500	100	0.000211
10	13	18	1	500	100	0.000211
11	16	17	1	500	100	0.000211
12	19	21	1	110	20	3.1E-05
13	21	23	1	110	20	3.1E-05
14	23	25	1	110	20	3.1E-05

Table A.2 Fault rates of the selected contingencies (transformers)

Cont #	From Bus	To Bus	Id	From kV	To kV	fault rate
15	10	12	1	500	110	0.000529
16	13	15	1	500	110	0.000634
17	16	19	1	110	500	0.000846
18	17	21	1	110	500	0.000529
19	18	25	1	110	500	0.000846

APPENDIX B

CPU TIME METRICS

The CPU metrics for the proposed method is provided in Table B.1 where the total number of time domain simulations performed for risk estimation is given by ψ. The metrics are based on the performance on a 64-bit Intel(R) Core(TM) i7 quad-core 3.4 GHz CPU with 16 GB RAM.

Table B.1 CPU time metrics

<table>
<tr><td rowspan="2">Time domain simulation</td><td>time /simulation</td><td>total time</td></tr>
<tr><td>2.5 s</td><td>2.5×ψ s</td></tr>
<tr><td colspan="2">Post-processing risk estimation</td><td>34.652 s</td></tr>
</table>

APPENDIX C

TEST SYSTEM (T1) DATA -- POWER FLOW DATA

The power flow per unit data are on 100 MVA system base. Bus 1 is defined as the slack bus. The power flow data provided is for the base case loading with high wind generation case.

Table C.1 Transmission line data

From	**To**	**kV**	**Ckt**	**R (pu)**	**X(pu)**	**B(pu)**
3	6	500	1	0.0019	0.0426	3.9
3	10	500	1	0.002	0.064	5.89
3	10	500	2	0.003	0.085	7.85
6	9	500	1	0.0019	0.0426	3.9
6	13	500	1	0.003	0.085	7.85
9	13	500	1	0.002	0.064	5.89
10	13	500	1	0.0019	0.0426	3.9
10	16	500	1	0.001	0.02	1.95
10	17	500	1	0.001	0.02	1.95
13	18	500	1	0.001	0.02	1.95
13	18	500	2	0.001	0.02	1.95
16	17	500	1	0.001	0.02	1.95
19	21	110	1	0.0022	0.02	0.011
19	21	110	2	0.0022	0.02	0.011
21	23	110	1	0.0022	0.02	0.011
21	23	110	2	0.0022	0.02	0.011
21	23	110	3	0.0022	0.02	0.011
23	25	110	1	0.0022	0.02	0.011
23	25	110	2	0.0022	0.02	0.011
23	25	110	3	0.0022	0.02	0.011

Table C.2 Transformer data

Transformer type	**R(pu)**	**X(pu)**
Generator transformers	0.0012	0.12
Substation transformers	0.0006	0.06
WTG POI unit transformers	0.001	0.1

Table C.3 Generator data

Bus	Name	kV	Pgen	Qmax	Qmin	MVA	Pmax	Pmin
1	Gen1	22	29.6	750	-600	2200	2000	0
2	Gen2	22	280	325	-250	1200	1000	0
4	Gen11	22	280	325	-250	1200	1000	0
5	Gen12	22	280	325	-250	1200	1000	0
7	Gen9	22	280	325	-250	1200	1000	0
11	Gen3	22	120	175	-95	600	500	0
14	Gen7	22	800	850	-750	2400	2000	0
20	Gen4	22	600	500	-400	1800	1500	0
22	Gen5	22	800	1000	-800	2400	2000	0
24	Gen6	22	2050	1500	-1200	4500	4000	0
26	Gen8	22	450	360	-280	1200	1000	0
8	WTG8	0.69	300	145	-145	334	300	14
28	WTG28	0.69	150	72.5	-72.5	167	150	7
29	WTG29	0.69	150	72.5	-72.5	167	150	7
30	WTG30	0.69	150	72.5	-72.5	167	150	7
31	WTG31	0.69	150	72.5	-72.5	167	150	7
32	WTG32	0.69	150	72.5	-72.5	167	150	7
33	WTG33	0.69	105	50	-50	117	105	5
34	WTG34	0.69	210	100	-100	234	210	10
35	WTG35	0.69	210	100	-100	234	210	10
36	WTG36	0.69	105	50	-50	117	105	5

*Pgen, Pmax and Pmin are in MW, Qmax and Qmin are in MVAR

Table C.4 Load data

Bus	Name	kV	Pload (MW)	Qload (MVAR)
12	ACBus12	110	183.75	52.5
15	ACBus15	110	262.5	127.05
19	ACBus19	110	1627.5	406.88
21	ACBus21	110	1575	393.75
23	ACBus23	110	2388.75	735
25	ACBus25	110	1575	393.75

Table C.5 Shunt data

Bus	Name	kV	G(pu)	B (pu)
3	ACBus3	500	0	-7.848
6	ACBus6	500	0	-7.213
9	ACBus9	500	0	-3.514
10	ACBus10	500	0	-9.749
12	ACBus12	110	0	0.572
13	ACBus13	500	0	-8.881
15	ACBus15	110	0	1.331
19	ACBus19	110	0	3.212
21	ACBus21	110	0	2.841
23	ACBus23	110	0	8.353
25	ACBus25	110	0	3.457

APPENDIX D

TEST SYSTEM (T1) DATA -- DYNAMIC DATA

The WTG data used in this paper is the default data provided in the GE PSLF user manual [49] for the GE generic WTG models -- GEWTG, EWTGFC and WNDTGE. The synchronous machine governor models are listed in Table D.1. Default governor model parameters are used as provided in the GE PSLF user manual [49]. The generator per unit dynamic data is on the corresponding machine MVA base.

Table D.1 Synchronous machine inertia constant and governor models

Bus	Name	H (s)	Governor model
1	Gen1	3.9	HYGOV
2	Gen2	3.9	HYGOV
4	Gen11	6.5	TGOV1
5	Gen12	6.5	TGOV1
7	Gen9	5.0	GGOV1
11	Gen3	5.0	GGOV1
14	Gen7	6.5	TGOV1
20	Gen4	6.0	TGOV1
22	Gen5	4.5	TGOV1
24	Gen6	4.5	TGOV1
26	Gen8	4.5	TGOV1

Table D.2 Synchronous generator dynamic data -- GENROU

Tpdo	7	D-axis transient rotor time constant, s
Tppdo	0.025	D-axis sub-transient rotor time constant, s
Tpqo	0.75	Q-axis transient rotor time constant, s
Tppqo	0.05	Q-axis sub-transient rotor time constant, s
D	0	Damping factor, pu
Ld	2.2	D-axis synchronous reactance, pu
Lq	2.1	Q-axis synchronous reactance, pu
Lpd	0.22	D-axis transient reactance, pu
Lpq	0.416	Q-axis transient reactance, pu
Lppd	0.2	D-axis sub-transient reactance, pu
Ll	0.147	Stator leakage reactance, pu
S1	0.109	Saturation factor at 1 pu flux
S12	0.3	Saturation factor at 1.2 pu flux
Ra	0	Stator resistance, pu
Rcomp	0	Compounding resistance for voltage control, pu
Xcomp	-0.07	Compounding reactance for voltage control, pu

Table D.3 Exciter data -- EXST1

Tr	0	Filter time constant, s
Vimax	0.1	Maximum error, pu
Vimin	-0.1	Minimum error, pu
Tc	1	Lead time constant, s
Tb	10	Lag time constant, s
Ka	100	Gain, pu
Ta	0.02	Time constant, s
Vrmax	5	Maximum controller output, pu
Vrmin	-5	Minimum controller output, pu
Kc	0.05	Excitation system regulation factor, pu
Kf	0	Rate feedback gain
Tf	1	Rate feedback time constant, s
Tc1	1	Lead time constant, s
Tb1	1	Lag time constant, s
Vamax	5	Maximum control element output, pu
Vamin	-5	Minimum control element output, pu
Xe	0.04	Excitation xfmr effective reactance, pu
Ilr	2.8	Maximum field current, pu
Klr	5	Gain on field current limit

Table D.4 Test system T1 – OOS relay settings

From bus	**To bus**	**Ckt**	**Outer circle**		**Inner circle**	
			forward reach (pu)	**angle (deg)**	**forward reach (pu)**	**angle (deg)**
10	17	1	0.01922	87.14	0.01602	87.14
10	16	1	0.01922	87.14	0.01602	87.14

APPENDIX E

TEST SYSTEM T2 – OOS RELAY SETTINGS, CONTINGENCY LIST AND OOS TRIP SUMMARY

Table E.1 Test system T2 – OOS relay settings

From bus	To bus	Ckt	Outer circle		Inner circle	
			forward reach (pu)	angle (deg)	forward reach (pu)	angle (deg)
6	28	1	0.04515	85.3	0.03010	85.3
6	79	1	0.04403	85.9	0.02935	85.9
10	13	1	0.02162	87.5	0.01441	87.5
33	83	1	0.04818	85.0	0.03212	85.0
33	85	1	0.03377	84.3	0.02251	84.3
44	114	1	0.01910	87.5	0.01273	87.5
44	114	2	0.03688	87.2	0.02459	87.2
79	7	1	0.02228	82.3	0.01486	82.3
80	7	1	0.02681	81.5	0.01788	81.5
83	84	1	0.01806	85.4	0.01204	85.4
84	20	1	0.03777	86.0	0.02518	86.0
89	35	1	0.03139	86.3	0.02092	86.3
96	69	1	0.12060	84.3	0.08040	84.3
96	72	1	0.18090	84.3	0.12060	84.3
108	69	1	0.24120	84.3	0.16080	84.3
111	77	1	0.28900	85.2	0.19267	85.2

Table E.2 Test system T2 – contingency list with fault rates

Contingency #	From bus	To bus	Ckt	Fault rate
1	2	80	1	0.0001603
2	4	79	1	0.0000525
3	6	28	1	0.0004654
4	6	79	1	0.0004542
5	6	106	1	0.0007955
6	7	10	1	0.0001607
7	10	13	1	0.0002234
8	13	15	1	0.0002234
9	15	35	1	0.0001688
10	18	10	1	0.0003115
11	18	20	1	0.0002569
12	18	28	1	0.0001807
13	18	82	1	0.0000782
14	20	24	1	0.0000248
15	24	15	1	0.0000745
16	24	86	1	0.0001390

17	31	84	1	0.0001539
18	33	83	1	0.0004964
19	33	85	1	0.0003475
20	38	40	1	0.0000732
21	40	44	1	0.0001452
22	42	44	1	0.0000037
23	44	114	1	0.0001973
24	46	49	1	0.0001018
25	46	91	1	0.0000416
26	49	113	1	0.0000701
27	54	61	1	0.0004049
28	57	63	1	0.0011789
29	57	66	1	0.0001775
30	57	93	1	0.0001018
31	57	98	1	0.0000446
32	61	63	1	0.0000248
33	63	66	1	0.0003413
34	63	97	1	0.0001986
35	66	67	1	0.0002587
36	72	69	1	0.0001891
37	77	102	1	0.0003032
38	79	7	1	0.0001024
39	80	7	1	0.0002743
40	80	79	1	0.0001179
41	80	81	1	0.0001452
42	81	7	1	0.0001452
43	82	10	1	0.0000419
44	82	24	1	0.0000920
45	83	84	1	0.0001861
46	83	85	1	0.0001479
47	84	20	1	0.0003891
48	84	28	1	0.0002507
49	86	87	1	0.0000517
50	86	88	1	0.0000422
51	86	89	1	0.0001042
52	87	89	1	0.0000517
53	88	89	1	0.0000943
54	88	105	1	0.0002978
55	89	35	1	0.0003239
56	89	38	1	0.0001117
57	89	90	1	0.0001526

58	90	44	1	0.0001539
59	91	49	1	0.0000416
60	92	61	1	0.0003100
61	93	63	1	0.0001018
62	94	69	1	0.0001512
63	96	69	1	0.0001008
64	96	72	1	0.0001512
65	97	66	1	0.0001986
66	98	66	1	0.0000446
67	99	46	1	0.0000683
68	99	115	1	0.0002507
69	100	69	1	0.0000101
70	101	69	1	0.0000202
71	101	75	1	0.0000121
72	101	100	1	0.0000101
73	103	102	1	0.0018193
74	104	101	1	0.0000252
75	104	108	1	0.0001260
76	106	117	1	0.0001241
77	106	119	1	0.0002482
78	108	69	1	0.0024820
79	110	108	1	0.0024820
80	111	77	1	0.0029784
81	113	57	1	0.0001564
82	113	92	1	0.0003100
83	113	116	1	0.0002128
84	114	46	1	0.0001799
85	114	99	1	0.0001117
86	115	46	1	0.0001309
87	116	57	1	0.0002128
88	117	119	1	0.0001241

Table E.3 Test system T2 – OOS tripping summary for case with line #89-38 tripped at pre-contingency and no wind or solar PV generation

Cont #	From bus	To bus	Ckt	ID	Tripped (s)	Cont #	From bus	To bus	Ckt	ID	Tripped (s)
3	96	69	1	1	3.162	38	6	28	1	1	1.879
3	111	77	1	1	2.512	38	96	69	1	1	3.167
4	96	69	1	1	3.183	38	111	77	1	1	1.892
4	96	72	1	1	4.154	39	6	28	1	1	1.896
4	111	77	1	1	2.467	39	111	77	1	1	1.883
4	96	69	1	1	3.279	39	6	28	1	1	2.617
4	96	72	1	1	5.950	39	79	7	1	1	2.421
4	108	69	1	1	4.967	39	111	77	1	1	2.029
4	111	77	1	1	5.746	40	6	28	1	1	2.746
5	44	114	1	1	3.196	40	79	7	1	1	2.475
5	96	69	1	1	2.754	40	96	69	1	1	3.625
5	96	72	1	1	3.658	40	111	77	1	1	1.958
5	111	77	1	1	2.029	40	96	69	1	1	2.858
5	44	114	1	1	4.383	40	111	77	1	1	2.092
5	44	114	2	2	3.546	41	96	69	1	1	2.771
5	96	69	1	1	2.917	41	111	77	1	1	2.017
5	96	72	1	1	3.808	41	6	28	1	1	2.650
5	111	77	1	1	2.300	41	79	7	1	1	2.471
6	44	114	2	2	9.942	41	80	7	1	1	2.471
6	96	69	1	1	6.554	41	111	77	1	1	2.042
6	96	72	1	1	5.525	42	96	69	1	1	3.025
6	108	69	1	1	8.667	42	111	77	1	1	2.158
6	111	77	1	1	9.312	42	6	28	1	1	4.371
7	96	69	1	1	5.483	42	44	114	1	1	4.000
7	96	72	1	1	4.687	42	79	7	1	1	4.346
7	108	69	1	1	7.025	42	96	69	1	1	2.925
7	96	69	1	1	2.754	42	96	72	1	1	3.962
7	96	72	1	1	5.037	42	111	77	1	1	2.158
7	108	69	1	1	4.537	43	96	69	1	1	3.596
8	96	69	1	1	5.633	43	111	77	1	1	1.962
8	96	72	1	1	5.258	43	96	69	1	1	2.662
8	44	114	2	2	7.729	43	96	72	1	1	5.792
8	96	69	1	1	2.996	43	108	69	1	1	4.354
8	96	72	1	1	3.917	44	96	69	1	1	2.571
8	111	77	1	1	2.275	44	96	72	1	1	3.767
9	96	69	1	1	3.129	44	108	69	1	1	4.154
9	96	72	1	1	4.458	44	111	77	1	1	4.875
9	108	69	1	1	4.854	44	96	69	1	1	5.617
9	111	77	1	1	5.521	44	96	72	1	1	4.967
10	96	69	1	1	5.554	44	108	69	1	1	7.183
10	96	72	1	1	4.871	44	111	77	1	1	7.946
10	108	69	1	1	6.767	45	96	69	1	1	5.167
10	111	77	1	1	7.554	45	96	72	1	1	4.687

11	96	69	1	1	2.896	45	111	77	1	1	7.450
11	96	72	1	1	4.862	46	33	83	1	1	1.558
11	108	69	1	1	5.996	47	33	83	1	1	1.621
11	111	77	1	1	6.854	47	111	77	1	1	2.775
11	96	69	1	1	5.767	48	111	77	1	1	3.112
11	96	72	1	1	4.975	48	84	20	1	1	1.475
12	96	69	1	1	5.433	49	84	20	1	1	1.617
12	96	72	1	1	4.992	54	111	77	1	1	5.408
12	96	69	1	1	3.321	56	96	69	1	1	2.233
12	96	72	1	1	4.537	56	96	72	1	1	5.217
12	108	69	1	1	4.846	56	111	77	1	1	5.483
12	111	77	1	1	5.583	57	96	69	1	1	2.850
13	6	28	1	1	3.146	57	96	72	1	1	4.708
13	84	20	1	1	2.629	57	111	77	1	1	8.975
13	96	69	1	1	3.504	57	96	69	1	1	2.167
13	96	72	1	1	4.254	57	96	72	1	1	4.221
13	111	77	1	1	2.533	57	108	69	1	1	6.617
13	33	83	1	1	7.196	58	96	72	1	1	5.150
13	44	114	1	1	3.796	58	96	72	1	1	7.962
13	96	69	1	1	2.733	59	96	69	1	1	8.308
13	96	72	1	1	3.617	59	96	72	1	1	7.562
13	108	69	1	1	7.046	59	96	72	1	1	7.904
13	111	77	1	1	1.846	60	96	69	1	1	4.396
14	44	114	1	1	3.158	60	96	72	1	1	3.417
14	96	69	1	1	2.700	60	108	69	1	1	6.408
14	96	72	1	1	3.579	60	111	77	1	1	9.117
14	111	77	1	1	1.892	61	96	69	1	1	8.171
14	111	77	1	1	1.225	61	96	72	1	1	7.583
15	96	69	1	1	4.542	62	96	69	1	1	8.137
15	111	77	1	1	1.221	62	96	72	1	1	3.700
15	96	69	1	1	2.450	62	108	69	1	1	9.883
15	96	72	1	1	3.625	62	96	69	1	1	7.962
15	111	77	1	1	1.712	62	96	72	1	1	7.192
16	96	69	1	1	5.850	63	96	69	1	1	1.571
16	96	72	1	1	5.500	63	96	72	1	1	2.487
16	96	69	1	1	3.262	63	108	69	1	1	5.562
16	96	72	1	1	6.175	63	111	77	1	1	6.212
16	111	77	1	1	1.546	63	96	72	1	1	3.708
17	44	114	1	1	5.187	63	108	69	1	1	9.658
17	96	69	1	1	3.446	64	96	72	1	1	2.704
17	96	72	1	1	4.833	64	108	69	1	1	5.708
17	111	77	1	1	2.437	64	96	69	1	1	7.696
18	33	85	1	1	1.625	64	108	69	1	1	9.383
19	33	85	1	1	1.667	65	96	69	1	1	2.583
19	33	83	1	1	1.517	65	108	69	1	1	5.075
20	33	83	1	1	1.612	66	96	72	1	1	8.092
20	96	72	1	1	8.117	67	96	72	1	1	8.487
21	96	72	1	1	7.929	68	96	72	1	1	8.229

21	96	69	1	1	8.737	70	96	69	1	1	1.704
21	96	72	1	1	7.425	70	96	72	1	1	3.133
22	96	72	1	1	4.504	70	108	69	1	1	5.346
24	96	69	1	1	7.875	71	96	69	1	1	1.629
24	96	72	1	1	4.308	71	96	72	1	1	2.987
24	108	69	1	1	9.454	71	108	69	1	1	5.329
25	96	69	1	1	4.400	71	111	77	1	1	2.208
25	96	72	1	1	3.417	72	111	77	1	1	2.062
25	108	69	1	1	6.425	74	96	69	1	1	9.050
25	111	77	1	1	8.933	74	96	72	1	1	8.096
25	96	69	1	1	7.892	75	96	69	1	1	4.946
25	96	72	1	1	4.262	75	96	72	1	1	4.417
25	108	69	1	1	9.467	75	108	69	1	1	6.533
26	96	72	1	1	7.942	76	96	69	1	1	6.579
26	44	114	1	1	2.625	76	96	72	1	1	5.679
26	44	114	2	2	1.925	76	108	69	1	1	8.396
26	96	69	1	1	1.958	76	111	77	1	1	9.125
26	96	72	1	1	2.104	77	96	69	1	1	3.708
26	108	69	1	1	4.850	77	96	72	1	1	6.104
27	44	114	1	1	3.246	77	108	69	1	1	5.079
27	44	114	2	2	2.075	77	96	69	1	1	6.583
27	96	69	1	1	2.096	77	96	72	1	1	5.683
27	96	72	1	1	2.233	77	108	69	1	1	8.392
27	96	72	1	1	4.479	77	111	77	1	1	9.121
28	96	72	1	1	7.767	78	96	69	1	1	4.054
28	96	69	1	1	8.137	78	111	77	1	1	2.442
28	96	72	1	1	7.487	79	96	69	1	1	1.942
29	96	72	1	1	7.671	79	96	72	1	1	3.254
29	96	69	1	1	8.079	79	111	77	1	1	6.087
29	96	72	1	1	4.021	81	96	69	1	1	7.967
29	108	69	1	1	9.771	81	96	72	1	1	4.058
30	96	72	1	1	8.021	81	108	69	1	1	9.692
30	96	69	1	1	8.179	82	96	69	1	1	8.137
30	96	72	1	1	3.625	82	96	72	1	1	3.837
31	96	72	1	1	3.858	82	108	69	1	1	9.904
33	44	114	2	2	3.025	82	96	69	1	1	7.712
33	96	69	1	1	8.517	82	96	72	1	1	3.992
33	96	72	1	1	3.846	82	108	69	1	1	9.492
34	96	72	1	1	7.950	83	96	69	1	1	7.767
34	96	69	1	1	8.337	83	96	72	1	1	4.117
34	96	72	1	1	3.921	83	108	69	1	1	9.475
35	96	72	1	1	4.404	87	96	72	1	1	7.829
36	96	72	1	1	8.583	88	96	69	1	1	7.925
36	96	72	1	1	1.583	88	96	72	1	1	3.808
37	96	69	1	1	1.729	88	108	69	1	1	9.771
37	96	72	1	1	9.133	88	96	69	1	1	3.667
37	111	77	1	1	1.612	88	96	72	1	1	6.158
38	111	77	1	1	1.358	88	108	69	1	1	5.021

APPENDIX F

PSLF EPCL CODE FOR AUTOMATION OF IMPACT ESTIMATION

```
/* this code will run the LLG dynamic simulation for risk assessment*/
$dyfile = "uts_wtf_sps2.dyd"
$rfile = "risk_test.rep"
$ifile="l_100_r_0.sav"
$infile1="contingency_list.txt"
$infile2="gen_type.txt"
$infile3 ="seq_data.txt"
$infile4="load_type.txt"
@return1 = setinput($infile1)
@return2 = setinput($infile2)
@return3 = setinput($infile3)
@return4 = setinput($infile4)
dim #gen_type_bus[76]
dim #gen_type_id[76]
dim #gen_zone[76]
dim #load_bus[6]
dim #load_zone[6]
dim #cont_type[19]
dim #cont_id[19]
dim #cont_efb[19]
dim #cont_etb[19]
dim #cont_ckt[19]
dim #seqbus[28]
dim #nseqr[28]
dim #nseqx[28]
dim #zseqr[28]
dim #zseqx[28]
@total_cont = 19
@total_gen = 76
@total_seq = 28
@total_loadbus = 6
for @par = 0 to @total_cont-1
        @return1 = input($infile1, #cont_type[@par], #cont_id[@par], #cont_efb[@par],
#cont_etb[@par], #cont_ckt[@par])
next
for @par = 0 to @total_gen-1
        @return2 = input($infile2, #gen_type_bus[@par], #gen_type_id[@par],
#gen_zone[@par])
next
for @par = 0 to @total_seq-1
        @return3 = input($infile3, #seqbus[@par], #nseqr[@par],  #nseqx[@par],
#zseqr[@par], #zseqx[@par])
        /* logterm(#seqbus[@par] , " ", #nseqr[@par] , " ",  #nseqx[@par] , " ",
#zseqr[@par] , " ", #zseqx[@par], "<") */
next
for @par = 0 to @total_loadbus-1
        @return4 = input($infile4, #load_bus[@par], #load_zone[@par])
next
/* format for simulation summary */
/* load ren cont type fb tb loc total_load_shed total_gen_trip */
@fixup = 0
@total_cont = 19
@i = getf($ifile)
@nbranch = casepar[0].nbrsec-1
@nxfmr  = casepar[0].ntran-1
@return = openlog("test_log.txt")
/* logprint("test_log.txt", "nbranch-", @nbranch," nxfmr-", @nxfmr, "<") */
for @step = 5 to 5
for @ren = 0 to 5
        $st = format(@step*5+100,0,0)
        $re = format(@ren*20,0,0)
        $outfile3="tripping_results_"+$st+"_"+$re+".txt"
        $outfile4 = "sim_2_"+$st+"_"+$re+".m"
        @i=openlog($outfile3)
        @i=setlog($outfile3)
        @i=openlog($outfile4)
        @i=setlog($outfile4)
        logprint($outfile4,"summary_",$st,"_",$re,"=[")
        $hfile="l_"+$st+"_r_"+$re+".sav"
```

```
for @cont = 0 to @total_cont-1
        dim #gen_pre[100]
        dim #gen_post[100]
        @tot_mw_gen = 0
        @tot_mvar_gen = 0
        @tot_mw_load = 0
        @tot_mvar_load = 0
        @in = 0
        @fixup = 0
        @wtgbase = 0
        @pvbase =0
        @nucbase = 0
        @coalbase = 0
        @hydrobase = 0
        @gasbase = 0
        @z1_gentrip = 0
        @z2_gentrip = 0
        @z3_gentrip = 0
        @z4_gentrip = 0
        @z5_gentrip = 0
        @z1_loadtrip = 0
        @z2_loadtrip = 0
        @z3_loadtrip = 0
        @z4_loadtrip = 0
        @z5_loadtrip = 0
        @z1_gen = 0
        @z2_gen = 0
        @z3_gen = 0
        @z4_gen = 0
        @z5_gen = 0
        @z1_load = 0
        @z2_load = 0
        @z3_load = 0
        @z4_load = 0
        @z5_load = 0
        @i = getf($hfile)
        for @loopg = 0 to casepar[0].ngen-1
                @gen_stat = gens[@loopg].st
                if (@gen_stat =1)
                        @tot_mw_gen = @tot_mw_gen + gens[@loopg].pgen
                        @tot_mvar_gen = @tot_mvar_gen + gens[@loopg].qgen
                        @igenbus = gens[@loopg].ibgen
                        @temp = bixst[@igenbus].extnum
                        #gen_pre[@in] = @temp
                        for @par = 0 to @total_gen-1
                                if (#gen_type_bus[@par]=@temp)
                                        if (#gen_type_id[@par] = 1)
                                                @coalbase = @coal-
base+gens[@loopg].pgen
                                        endif
                                        if (#gen_type_id[@par] = 2)
                                                @hydrobase = @hydro-
base+gens[@loopg].pgen
                                        endif
                                        if (#gen_type_id[@par] = 3)
                                                @gasbase = @gas-
base+gens[@loopg].pgen
                                        endif
                                        if (#gen_type_id[@par] = 4)
                                                @wtgbase =
@wtgbase+gens[@loopg].pgen
                                        endif
                                        if (#gen_type_id[@par] = 5)
                                                @pvbase =
@pvbase+gens[@loopg].pgen
                                        endif
                                        if (#gen_type_id[@par] = 6)
                                                @nucbase = @nu-
cbase+gens[@loopg].pgen
                                        endif
```

```
                                                if (#gen_zone[@par] = 1)
                                                        @z1_gen = @z1_gen +
gens[@loopg].pgen
                                                endif
                                                if (#gen_zone[@par] = 2)
                                                        @z2_gen = @z2_gen +
gens[@loopg].pgen
                                                endif
                                                if (#gen_zone[@par] = 3)
                                                        @z3_gen = @z3_gen +
gens[@loopg].pgen
                                                endif
                                                if (#gen_zone[@par] = 4)
                                                        @z4_gen = @z4_gen +
gens[@loopg].pgen
                                                endif
                                                if (#gen_zone[@par] = 5)
                                                        @z5_gen = @z5_gen +
gens[@loopg].pgen
                                                endif
                                        endif
                                next
                                @in = @in + 1
                        endif
                next
                for @loopl = 0 to casepar[0].nload-1
                        @tot_mw_load = @tot_mw_load + (load[@loopl].p)
                        @tot_mvar_load = @tot_mvar_load + (load[@loopl].q)
                        @lbus = load[@loopl].lbus
                        @temp = busd[@lbus].extnum
                        for @par = 0 to @total_loadbus-1
                                if (#load_bus[@par]=@temp)
                                        if (#load_zone[@par] = 1)
                                                @z1_load = @z1_load + (load[@loopl].p)
                                        endif
                                        if (#load_zone[@par] = 2)
                                                @z2_load = @z2_load + (load[@loopl].p)
                                        endif
                                        if (#load_zone[@par] = 3)
                                                @z3_load = @z3_load + (load[@loopl].p)
                                        endif
                                        if (#load_zone[@par] = 4)
                                                @z4_load = @z4_load + (load[@loopl].p)
                                        endif
                                        if (#load_zone[@par] = 5)
                                                @z5_load = @z5_load + (load[@loopl].p)
                                        endif
                                endif
                        next
                next
                $ct = format(@cont+1,0,0)
                if (#cont_type[@cont] =1)
                        for @loc_ndx = 0 to 2
                                if(@loc_ndx < 1)
                                        @loc = 0
                                endif
                                if(@loc_ndx = 1)
                                        @loc = 0.5
                                endif
                                if(@loc_ndx >1)
                                        @loc = 1
                                endif
                                @fixup = 0
                                @i = getf($hfile)
                                solpar[0].itnrmx = 25
                                solpar[0].itnrvl = 5
                                solpar[0].tapadj =1
                                solpar[0].swsadj = 1
                                @i = soln()
                                @i = psds()
```

```
$lc = format(@loc_ndx,0,0)
$pfile = "test.chf"
/*@i  = psds()*/
$pname = "2L_c"+$ct+"_l"+$lc+"_b"+$st+"_r"+$re+".chf"
logprint($outfile3,"< <", $pname, "<")
logprint($outfile3, "Loading above basecase % ",$st, "<")
logprint($outfile3, "Renewable penetration % ",$re, "<")
logprint($outfile3, "Contingency#",@cont+1, "<")
logprint($outfile3, "type:LLG:line<")
logprint($outfile3, "location ",@loc," <")
logprint($outfile3, "FromBus ",#cont_efb[@cont]," <")
logprint($outfile3, "ToBus ",#cont_etb[@cont]," <")
logprint($outfile3, "ckid ",#cont_ckt[@cont]," <")
logprint($outfile3, "<Total_MW_generation_online-pre-
contingency: ",@tot_mw_gen," <")
logprint($outfile3, "Total_MVAR_generation_online-pre-
contingency: ",@tot_mvar_gen," <")
logprint($outfile3, "Total_MW_load-pre-contingency:
",@tot_mw_load," <")
logprint($outfile3, "Total_MVAR_load-pre-contingency:
",@tot_mvar_load," <")
logprint($outfile3, "Zone1_MW_generation_pre-contingency:
",@z1_gen," <")
logprint($outfile3, "Zone1_MW_load_online-pre-
contingency: ",@z1_load," <")
logprint($outfile3, "Zone2_MW_generation_pre-contingency:
",@z2_gen," <")
logprint($outfile3, "Zone2_MW_load_online-pre-
contingency: ",@z2_load," <")
logprint($outfile3, "Zone3_MW_generation_pre-contingency:
",@z3_gen," <")
logprint($outfile3, "Zone3_MW_load_online-pre-
contingency: ",@z3_load," <")
logprint($outfile3, "Zone4_MW_generation_pre-contingency:
",@z4_gen," <")
logprint($outfile3, "Zone4_MW_load_online-pre-
contingency: ",@z4_load," <")
logprint($outfile3, "Zone5_MW_generation_pre-contingency:
",@z5_gen," <")
logprint($outfile3, "Zone5_MW_load_online-pre-
contingency: ",@z5_load," <")
logprint($outfile3, "Generators_online_pre-contingency:
<")
for @temp  = 0 to @in-1
        logprint($outfile3, #gen_pre[@temp]," ")
next
logprint($outfile3, "<<")
@i = rdyd($dyfile, $rfile, "1")
dypar[0].delt=0.004
dypar[0].angle_ref_gen = 0
@i = init($pfile, $rfile, "0","0")
dypar[0].nplot = 1
dypar[0].nscreen = 100
dypar[0].tpause = 1
@i = run()
dypar[0].nplot = 1
dypar[0].nscreen = 100
dypar[0].tpause = 20
@reffec = 0
@xeffec = 0
@nr = 0
@nx = 0
@zr = 0
@zx = 0
if (#cont_ckt[@cont] =1)
        @midbus = 990000 + #cont_efb[@cont] * 100 +
#cont_etb[@cont]
endif
if (#cont_ckt[@cont] =2)
```

```
				@midbus = 980000 + #cont_efb[@cont] * 100 +
#cont_etb[@cont]
			endif
			for @par = 0 to @total_seq-1
				if( #seqbus[@par]= #cont_efb[@cont])
					if(@loc = 0)
						@nr = #nseqr[@par]
						@nx = #nseqr[@par]
						@zr = #zseqr[@par]
						@zx = #zseqx[@par]
					endif
				endif
				if( #seqbus[@par]= #cont_etb[@cont])
					if(@loc = 1)
						@nr = #nseqr[@par]
						@nx = #nseqr[@par]
						@zr = #zseqr[@par]
						@zx = #zseqx[@par]
					endif
				endif
				if( #seqbus[@par]= @midbus)
					if(@loc = 0.5)
						@nr = #nseqr[@par]
						@nx = #nseqr[@par]
						@zr = #zseqr[@par]
						@zx = #zseqx[@par]
					endif
				endif
			next
			/* logterm(@nr, " ", @nx, " ", @zr, " ", @zx) */
			@reffec=((@nr*@zr-
@nx*@zx)*(@nr+@zr)+(@nx*@zr+@nr*@zx)*(@nx+@zx))/((@zr+@nr)*(@zr+@nr)+(@zx+@nx)*(@zx+@nx))
			@xeffec=((@nx*@zr+@nr*@zx)*(@nr+@zr)-(@nr*@zr-
@nx*@zx)*(@nx+@zx))/((@zr+@nr)*(@zr+@nr)+(@zx+@nx)*(@zx+@nx))
			dypar[0].faultr = @reffec
			dypar[0].faultx = @xeffec
			dypar[0].fault_from = format(#cont_efb[@cont],0,0)
			dypar[0].fault_to = format(#cont_etb[@cont],0,0)
			$ckid = format(#cont_ckt[@cont],0,0)
			dypar[0].fault_ck = $ckid
			dypar[0].fault_sec = 1
			dypar[0].fault_position = @loc
			dypar[0].t_fault_on = 1.0
			dypar[0].t_from_clear = 1.0833
			dypar[0].t_to_clear = 1.0833
			@i = run()
			logprint("test_log.txt", "dynamics done", @i, "<")

			@tot_mw_gen_trip = 0
			@tot_mvar_gen_trip = 0
			@tot_mw_gen_post= 0
			@tot_mvar_gen_post =0
			@in = 0
			@coal=@coalbase
			@hydro=@hydrobase
			@gas=@gasbase
			@wtg=@wtgbase
			@pv=@pvbase
			@nuc=@nucbase
			@z1_gentrip = @z1_gen
			@z2_gentrip = @z2_gen
			@z3_gentrip = @z3_gen
			@z4_gentrip = @z4_gen
			@z5_gentrip = @z5_gen

			for @loopg = 0 to casepar[0].ngen-1
				if (gens[@loopg].st =1)
					@tot_mw_gen_post = @tot_mw_gen_post +
gens[@loopg].pgen
```

```
                    @tot_mvar_gen_post = @tot_mvar_gen + gens[@loopg].qgen
                    @igenbus = gens[@loopg].ibgen
                    @temp = bixst[@igenbus].extnum
                    #gen_post[@in] = @temp
                    for @par = 0 to @total_gen-1
                            if (#gen_type_bus[@par] = @temp)
                                    if (#gen_type_id[@par] = 1)
                                            @coal = @coal-gens[@loopg].pgen
                                    endif
                                    if (#gen_type_id[@par] = 2)
                                            @hydro = @hydro-gens[@loopg].pgen
                                    endif
                                    if (#gen_type_id[@par] = 3)
                                            @gas = @gas-gens[@loopg].pgen
                                    endif
                                    if (#gen_type_id[@par] = 4)
                                            @wtg = @wtg-gens[@loopg].pgen
                                    endif
                                    if (#gen_type_id[@par] = 5)
                                            @pv = @pv-gens[@loopg].pgen
                                    endif
                                    if (#gen_type_id[@par] = 6)
                                            @nuc = @nuc-gens[@loopg].pgen
                                    endif
                                    if (#gen_zone[@par] = 1)
                                            @z1_gentrip = @z1_gentrip - gens[@loopg].pgen
                                    endif
                                    if (#gen_zone[@par] = 2)
                                            @z2_gentrip = @z2_gentrip - gens[@loopg].pgen
                                    endif
                                    if (#gen_zone[@par] = 3)
                                            @z3_gentrip = @z3_gentrip - gens[@loopg].pgen
                                    endif
                                    if (#gen_zone[@par] = 4)
                                            @z4_gentrip = @z4_gentrip - gens[@loopg].pgen
                                    endif
                                    if (#gen_zone[@par] = 5)
                                            @z5_gentrip = @z5_gentrip - gens[@loopg].pgen
                                    endif
                            endif
                    next
                    @in = @in +1
            endif
    next
    @tot_mw_load_post = 0
    @tot_mvar_load_post = 0
    @tot_load_mw_shed = 0
    @tot_load_mvar_shed = 0
    @z1_loadtrip = @z1_load
    @z2_loadtrip = @z2_load
    @z3_loadtrip = @z3_load
    @z4_loadtrip = @z4_load
```

```
                                @z5_loadtrip = @z5_load
                                for @loopl = 0 to casepar[0].nload-1
                                        @tot_mw_load_post = @tot_mw_load_post +
(load[@loopl].g) * (load[@loopl].shed)
                                        @tot_mvar_load_post = @tot_mvar_load_post +
(load[@loopl].b) * (load[@loopl].shed)
                                        @lbus = load[@loopl].lbus
                                        @temp = busd[@lbus].extnum
                                        for @par = 0 to @total_loadbus-1
                                                if (#load_bus[@par]=@temp)
                                                        if (#load_zone[@par] = 1)
                                                                @z1_loadtrip = @z1_load-
trip - (load[@loopl].g) * (load[@loopl].shed)
                                                        endif
                                                        if (#load_zone[@par] = 2)
                                                                @z2_loadtrip = @z2_load-
trip - (load[@loopl].g) * (load[@loopl].shed)
                                                        endif
                                                        if (#load_zone[@par] = 3)
                                                                @z3_loadtrip = @z3_load-
trip - (load[@loopl].g) * (load[@loopl].shed)
                                                        endif
                                                        if (#load_zone[@par] = 4)
                                                                @z4_loadtrip = @z4_load-
trip - (load[@loopl].g) * (load[@loopl].shed)
                                                        endif
                                                        if (#load_zone[@par] = 5)
                                                                @z5_loadtrip = @z5_load-
trip - (load[@loopl].g) * (load[@loopl].shed)
                                                        endif
                                                endif
                                        next
                                next
                                @tot_load_mw_shed  = @tot_mw_load - @tot_mw_load_post
                                @tot_load_mvar_shed  = @tot_mvar_load -
@tot_mvar_load_post
                                logprint("test_log.txt", "loc-", @loc, "<")
                                logprint($outfile3, "<Total_MW_generation_online-post-
contingency: ",@tot_mw_gen_post," <")
                                logprint($outfile3, "Total_MVAR_generation_online-post-
contingency: ",@tot_mvar_gen_post," <")
                                logprint($outfile3, "Total_MW_generation_tripped:
",@tot_mw_gen-@tot_mw_gen_post," <")
                                logprint($outfile3, "Total_MVAR_generation_tripped:
",@tot_mvar_gen-@tot_mvar_gen_post," <")
                                logprint($outfile3, "Total_MW_load_post-contingency:
",@tot_mw_load_post," <")
                                logprint($outfile3, "Total_MVAR_post-contingency:
",@tot_mvar_load_post," <")
                                logprint($outfile3, "Total_MW_load_shed_post-contingency:
",@tot_load_mw_shed," <")
                                logprint($outfile3, "Total_MVAR_load_shed_post-
contingency: ",@tot_load_mvar_shed," <")
                                logprint($outfile3, "Zone1_MW_gen_trip: ",@z1_gentrip,"
<")
                                logprint($outfile3, "Zone1_MW_load_trip: ",@z1_loadtrip,"
<")
                                logprint($outfile3, "Zone2_MW_gen_trip: ",@z2_gentrip,"
<")
                                logprint($outfile3, "Zone2_MW_load_trip: ",@z2_loadtrip,"
<")
                                logprint($outfile3, "Zone3_MW_gen_trip: ",@z3_gentrip,"
<")
                                logprint($outfile3, "Zone3_MW_load_trip: ",@z3_loadtrip,"
<")
                                logprint($outfile3, "Zone4_MW_gen_trip: ",@z4_gentrip,"
<")
                                logprint($outfile3, "Zone4_MW_load_trip: ",@z4_loadtrip,"
<")
```

```
                                logprint($outfile3, "Zone5_MW_gen_trip: ",@z5_gentrip,"
<")
                                logprint($outfile3, "Zone5_MW_load_trip: ",@z5_loadtrip,"
<")
                                logprint($outfile3, "Generators_online_post-contingency:
<")
                                for @temp  = 0 to @in-1
                                        logprint($outfile3, #gen_post[@temp]," ")
                                next
                                logprint($outfile3, "<Coal_base: ",@coalbase,"<")
                                logprint($outfile3, "Hyro_base: ",@hydrobase,"<")
                                logprint($outfile3, "Gas_base: ",@gasbase,"<")
                                logprint($outfile3, "Nuclear_base: ",@nucbase,"<")
                                logprint($outfile3, "WTG_base: ",@wtgbase,"<")
                                logprint($outfile3, "PV_base: ",@pvbase,"<")
                                logprint($outfile3, "<<")
                                /* load ren cont type fb tb loc tot_load_shed
tot_gen_tripped */
                                /* LLL = 3, LLG = 2, LL = 1, SLG = 0 */
                                @gen_mwtrip = 0
                                @gen_mvartrip = 0
                                @gen_mwtrip  = @tot_mw_gen-@tot_mw_gen_post
                                @gen_mvartrip = @tot_mvar_gen-@tot_mvar_gen_post
                                logprint($outfile4, 100+@step*5, " ", @ren*20," ",
@cont+1," 2 ", #cont_efb[@cont], " ",#cont_etb[@cont], " ")
                                logprint($outfile4,#cont_ckt[@cont], " ", @loc," ",
@tot_load_mw_shed, " ",@tot_load_mvar_shed, " ",@gen_mwtrip)
                                logprint($outfile4," ",@gen_mvartrip)
                                logprint($outfile4," ",@coalbase, " ",@hydrobase,"
",@gasbase)
                                logprint($outfile4," ",@nucbase, " ",@wtgbase,"
",@pvbase)
                                logprint($outfile4," ",@coal, " ",@hydro," ",@gas)
                                logprint($outfile4," ",@nuc, " ",@wtg," ",@pv)
                                logprint($outfile4," ",@z1_gen, " ",@z2_gen," ",@z3_gen,
" ", @z4_gen, " ",@z5_gen)
                                logprint($outfile4," ",@z1_load, " ",@z2_load,"
",@z3_load, " ", @z4_load, " ",@z5_load)
                                logprint($outfile4," ",@z1_gentrip, " ",@z2_gentrip,"
",@z3_gentrip, " ", @z4_gentrip, " ",@z5_gentrip)
                                logprint($outfile4," ",@z1_loadtrip, " ",@z2_loadtrip,"
",@z3_loadtrip, " ", @z4_loadtrip, " ",@z5_loadtrip, "<")

                                @i = dsst()
                        next
                endif
                if (#cont_type[@cont] =2)
                        for @loc = 0 to 1
                                @fixup = 0
                                @i = getf($hfile)
                                solpar[0].itnrmx = 25
                                solpar[0].itnrvl = 5
                                solpar[0].tapadj =1
                                solpar[0].swsadj = 1
                                @i = soln()
                                @i = psds()
                                $lc = format(@loc,0,0)
                                /*@i  = psds()*/
                                @i = rdyd($dyfile, $rfile, "1")
                                $ct = format(@cont,0,0)
                                /*logbuf($pfile,"test.chf")*/
                                $pfile = "test.chf"
                                $pname = "2T_c"+$ct+"_l"+$lc+"_b"+$st+"_r"+$re+".chf"
                                logprint($outfile3,"< <", $pname, "<")
                                logprint($outfile3, "Loading above basecase % ",$st, "<")
                                logprint($outfile3, "Renewable penetration % ",$re, "<")
                                logprint($outfile3, "Contingency#",@cont, "<")
                                logprint($outfile3, "type:LLG:transformer_bus<")
                                logprint($outfile3, "location ",@loc," <")
                                logprint($outfile3, "FromBus ",#cont_efb[@cont]," <")
```

```
logprint($outfile3, "ToBus ",#cont_etb[@cont]," <")
logprint($outfile3, "ckid ",#cont_ckt[@cont]," <")
logprint($outfile3, "< Total_MW_generation_online-pre-
contingency: ",@tot_mw_gen," <")
logprint($outfile3, "Total_MVAR_generation_online-pre-
contingency: ",@tot_mvar_gen," <")
logprint($outfile3, "Total_MW_load-pre-contingency:
",@tot_mw_load," <")
logprint($outfile3, "Total_MVAR_load-pre-contingency:
",@tot_mvar_load," <")
logprint($outfile3, "Zone1_MW_generation_pre-contingency:
",@z1_gen," <")
logprint($outfile3, "Zone1_MW_load_online-pre-
contingency: ",@z1_load," <")
logprint($outfile3, "Zone2_MW_generation_pre-contingency:
",@z2_gen," <")
logprint($outfile3, "Zone2_MW_load_online-pre-
contingency: ",@z2_load," <")
logprint($outfile3, "Zone3_MW_generation_pre-contingency:
",@z3_gen," <")
logprint($outfile3, "Zone3_MW_load_online-pre-
contingency: ",@z3_load," <")
logprint($outfile3, "Zone4_MW_generation_pre-contingency:
",@z4_gen," <")
logprint($outfile3, "Zone4_MW_load_online-pre-
contingency: ",@z4_load," <")
logprint($outfile3, "Zone5_MW_generation_pre-contingency:
",@z5_gen," <")
logprint($outfile3, "Zone5_MW_load_online-pre-
contingency: ",@z5_load," <")
logprint($outfile3, "Generators_online_pre-contingency:
<")

for @temp  = 0 to @in-1
        logprint($outfile3, #gen_pre[@temp]," ")
next
logprint($outfile3, "<<")
dypar[0].delt=0.004
dypar[0].angle_ref_gen = 0
@i = init($pfile, $rfile, "0","0")
dypar[0].nplot = 1
dypar[0].nscreen = 100
dypar[0].tpause = 1
@i = run()
dypar[0].nplot = 1
dypar[0].nscreen = 100
dypar[0].tpause = 1.0833
@reffec = 0
@xeffec = 0
@nr = 0
@nx = 0
@zr = 0
@zx = 0
for @par = 0 to @total_seq-1
        if( #seqbus[@par]= #cont_efb[@cont])
                if(@loc = 0)
                        @nr = #nseqr[@par]
                        @nx = #nseqr[@par]
                        @zr = #zseqr[@par]
                        @zx = #zseqx[@par]
                endif
        endif
        if( #seqbus[@par]= #cont_etb[@cont])
                if(@loc = 1)
                        @nr = #nseqr[@par]
                        @nx = #nseqr[@par]
                        @zr = #zseqr[@par]
                        @zx = #zseqx[@par]
                endif
        endif
next
```

```
                                @reffec=((@nr*@zr-
@nx*@zx)*(@nr+@zr)+(@nx*@zr+@nr*@zx)*(@nx+@zx))/((@zr+@nr)*(@zr+@nr)+(@zx+@nx)*(@zx+@nx))
                                @xeffec=((@nx*@zr+@nr*@zx)*(@nr+@zr)-(@nr*@zr-
@nx*@zx)*(@nx+@zx))/((@zr+@nr)*(@zr+@nr)+(@zx+@nx)*(@zx+@nx))
                                dypar[0].faultr = @reffec
                                dypar[0].faultx = @xeffec
                                dypar[0].faulton = 1
                                if (@loc >0 )
                                        dypar[0].faultloc = format(#cont_efb[@cont],0,0)
                                else
                                        dypar[0].faultloc = format(#cont_etb[@cont],0,0)
                                endif
                                @i = run()
                                dypar[0].nplot = 1
                                dypar[0].nscreen = 100
                                dypar[0].tpause = 20
                                dypar[0].faulton = 0
                                for @test = 0 to @nxfmr
                                        @ifb = tran[@test].ifrom
                                        @itb = tran[@test].ito
                                        @efb = bixst[@ifb].extnum
                                        @etb = bixst[@itb].extnum
                                        if(@efb = #cont_efb[@cont] and @etb =
#cont_etb[@cont])
                                                tran[@test].st = 0
                                                logprint($outfile3, "Transformer tripped:
",#cont_efb[@cont], " ",#cont_etb[@cont]," <")
                                                quitfor
                                        endif
                                next
                                @i = run()

                                @tot_mw_gen_post =0
                                @tot_mvar_gen_post =0
                                @tot_mw_gen_trip = 0
                                @tot_mvar_gen_trip = 0
                                @in = 0
                                @coal=@coalbase
                                @hydro=@hydrobase
                                @gas=@gasbase
                                @wtg=@wtgbase
                                @pv=@pvbase
                                @nuc=@nucbase
                                @z1_gentrip = @z1_gen
                                @z2_gentrip = @z2_gen
                                @z3_gentrip = @z3_gen
                                @z4_gentrip = @z4_gen
                                @z5_gentrip = @z5_gen
                                for @loopg = 0 to casepar[0].ngen-1
                                        if (gens[@loopg].st =1)
                                                @tot_mw_gen_post  = @tot_mw_gen_post  +
gens[@loopg].pgen
                                                @tot_mvar_gen_post  = @tot_mvar_gen_post
+ gens[@loopg].qgen
                                                @igenbus = gens[@loopg].ibgen
                                                @temp = bixst[@igenbus].extnum
                                                #gen_post[@in] = @temp
                                                for @par = 0 to @total_gen-1
                                                        if (#gen_type_bus[@par] = @temp)
                                                                if (#gen_type_id[@par] =
1)
                                                                        @coal = @coal-
gens[@loopg].pgen
                                                                endif
                                                                if (#gen_type_id[@par] =
2)
                                                                        @hydro = @hydro-
gens[@loopg].pgen
                                                                endif
```

```
                                                            if (#gen_type_id[@par] =
3)
                                                                    @gas = @gas-
gens[@loopg].pgen
                                                            endif
                                                            if (#gen_type_id[@par] =
4)
                                                                    @wtg = @wtg-
gens[@loopg].pgen
                                                            endif
                                                            if (#gen_type_id[@par] =
5)
                                                                    @pv = @pv-
gens[@loopg].pgen
                                                            endif
                                                            if (#gen_type_id[@par] =
6)
                                                                    @nuc = @nuc-
gens[@loopg].pgen
                                                            endif
                                                            if (#gen_zone[@par] = 1)
                                                                    @z1_gentrip =
@z1_gentrip - gens[@loopg].pgen
                                                            endif
                                                            if (#gen_zone[@par] = 2)
                                                                    @z2_gentrip =
@z2_gentrip - gens[@loopg].pgen
                                                            endif
                                                            if (#gen_zone[@par] = 3)
                                                                    @z3_gentrip =
@z3_gentrip - gens[@loopg].pgen
                                                            endif
                                                            if (#gen_zone[@par] = 4)
                                                                    @z4_gentrip =
@z4_gentrip - gens[@loopg].pgen
                                                            endif
                                                            if (#gen_zone[@par] = 5)
                                                                    @z5_gentrip =
@z5_gentrip - gens[@loopg].pgen
                                                            endif
                                                    endif
                                            next
                                            @in = @in +1
                                    endif
                            next
                            @tot_mw_load_post = 0
                            @tot_mvar_load_post = 0
                            @tot_load_mw_shed = 0
                            @tot_load_mvar_shed = 0
                            @z1_loadtrip = @z1_load
                            @z2_loadtrip = @z2_load
                            @z3_loadtrip = @z3_load
                            @z4_loadtrip = @z4_load
                            @z5_loadtrip = @z5_load
                            for @loopl = 0 to casepar[0].nload-1
                                    @tot_mw_load_post = @tot_mw_load_post +
(load[@loopl].g) * (load[@loopl].shed)
                                    @tot_mvar_load_post = @tot_mvar_load_post +
(load[@loopl].b) * (load[@loopl].shed)
                                    @lbus = load[@loopl].lbus
                                    @temp = busd[@lbus].extnum
                                    for @par = 0 to @total_loadbus-1
                                            if (#load_bus[@par]=@temp)
                                                    if (#load_zone[@par] = 1)
                                                            @z1_loadtrip = @z1_load-
trip - (load[@loopl].g) * (load[@loopl].shed)
                                                    endif
                                                    if (#load_zone[@par] = 2)
                                                            @z2_loadtrip = @z2_load-
trip - (load[@loopl].g) * (load[@loopl].shed)
```

```
                                        endif
                                        if (#load_zone[@par] = 3)
                                                @z3_loadtrip = @z3_load-
trip - (load[@loopl].g) * (load[@loopl].shed)
                                        endif
                                        if (#load_zone[@par] = 4)
                                                @z4_loadtrip = @z4_load-
trip - (load[@loopl].g) * (load[@loopl].shed)
                                        endif
                                        if (#load_zone[@par] = 5)
                                                @z5_loadtrip = @z5_load-
trip - (load[@loopl].g) * (load[@loopl].shed)
                                        endif
                                endif
                        next
                next
                @tot_load_mw_shed  = @tot_mw_load - @tot_mw_load_post
                @tot_load_mvar_shed  = @tot_mvar_load -
@tot_mvar_load_post
                logprint("test_log.txt", "loc-", @loc, "<")
                logprint($outfile3, "<Total_MW_generation_online-post-
contingency: ",@tot_mw_gen_post," <")
                logprint($outfile3, "Total_MVAR_generation_online-post-
contingency: ",@tot_mvar_gen_post," <")
                logprint($outfile3, "Total_MW_generation_tripped:
",@tot_mw_gen-@tot_mw_gen_post," <")
                logprint($outfile3, "Total_MVAR_generation_tripped:
",@tot_mvar_gen-@tot_mvar_gen_post," <")
                logprint($outfile3, "Total_MW_load_post-contingency:
",@tot_mw_load_post," <")
                logprint($outfile3, "Total_MVAR_post-contingency:
",@tot_mvar_load_post," <")
                logprint($outfile3, "Total_MW_load_shed_post-contingency:
",@tot_load_mw_shed," <")
                logprint($outfile3, "Total_MVAR_load_shed_post-
contingency: ",@tot_load_mvar_shed," <")
                logprint($outfile3, "Zone1_MW_gen_trip: ",@z1_gentrip,"
<")
                logprint($outfile3, "Zone1_MW_load_trip: ",@z1_loadtrip,"
<")
                logprint($outfile3, "Zone2_MW_gen_trip: ",@z2_gentrip,"
<")
                logprint($outfile3, "Zone2_MW_load_trip: ",@z2_loadtrip,"
<")
                logprint($outfile3, "Zone3_MW_gen_trip: ",@z3_gentrip,"
<")
                logprint($outfile3, "Zone3_MW_load_trip: ",@z3_loadtrip,"
<")
                logprint($outfile3, "Zone4_MW_gen_trip: ",@z4_gentrip,"
<")
                logprint($outfile3, "Zone4_MW_load_trip: ",@z4_loadtrip,"
<")
                logprint($outfile3, "Zone5_MW_gen_trip: ",@z5_gentrip,"
<")
                logprint($outfile3, "Zone5_MW_load_trip: ",@z5_loadtrip,"
<")
                logprint($outfile3, "Generators_online_post-contingency:
<")
                for @temp  = 0 to @in-1
                        logprint($outfile3, #gen_post[@temp]," ")
                next
                logprint($outfile3, "<Coal_base: ",@coalbase,"<")
                logprint($outfile3, "Hyro_base: ",@hydrobase,"<")
                logprint($outfile3, "Gas_base: ",@gasbase,"<")
                logprint($outfile3, "Nuclear_base: ",@nucbase,"<")
                logprint($outfile3, "WTG_base: ",@wtgbase,"<")
                logprint($outfile3, "PV_base: ",@pvbase,"<")
                logprint($outfile3, "<<")
                @gen_mwtrip = 0
                @gen_mvartrip = 0
```

```
                                @gen_mwtrip  = @tot_mw_gen-@tot_mw_gen_post
                                @gen_mvartrip = @tot_mvar_gen-@tot_mvar_gen_post
                                logprint($outfile4, 100+@step*5, " ", @ren*20," ",
@cont+1," 2 ", #cont_efb[@cont], " ")
                                logprint($outfile4,#cont_etb[@cont], " ",
#cont_ckt[@cont], " ", @loc, " ",@tot_load_mw_shed)
                                logprint($outfile4," ",@tot_load_mvar_shed, "
",@gen_mwtrip," ",@gen_mwtrip)
                                logprint($outfile4," ",@coalbase, " ",@hydrobase,"
",@gasbase)
                                logprint($outfile4," ",@nucbase, " ",@wtgbase,"
",@pvbase)
                                logprint($outfile4," ",@coal, " ",@hydro," ",@gas)
                                logprint($outfile4," ",@nuc, " ",@wtg," ",@pv)
                                logprint($outfile4," ",@z1_gen, " ",@z2_gen," ",@z3_gen,
" ", @z4_gen, " ",@z5_gen)
                                logprint($outfile4," ",@z1_load, " ",@z2_load,"
",@z3_load, " ", @z4_load, " ",@z5_load)
                                logprint($outfile4," ",@z1_gentrip, " ",@z2_gentrip,"
",@z3_gentrip, " ", @z4_gentrip, " ",@z5_gentrip)
                                logprint($outfile4," ",@z1_loadtrip, " ",@z2_loadtrip,"
",@z3_loadtrip, " ", @z4_loadtrip, " ",@z5_loadtrip, "<")
                                @i = dsst()
                        next
                endif
        next
        logprint($outfile4, "];")
next
next
stop()
end
```

APPENDIX G

MATLAB CODE FOR RISK ESTIMATION

```matlab
clc;
clear all;
%% This matlab code evaluates the risk of the test power system for different loading
and
%%
c_orig = 85;
c_emerg = 85;
downtime = 1;
c_load = 1;
c_repair = 156000;
n_load = 18;
n_ren = 6;
n_cont = 19;
n_fault = 4;
%% get wind distribution
wtg_model_1
wtg_model_2
%% initialize variables
risk_cont = zeros(n_ren,n_load,n_cont);
risk_overall = zeros(n_ren,n_load);
z1_risk_cont= zeros(n_ren,n_load,n_cont);
z2_risk_cont= zeros(n_ren,n_load,n_cont);
z3_risk_cont= zeros(n_ren,n_load,n_cont);
z4_risk_cont= zeros(n_ren,n_load,n_cont);
z5_risk_cont= zeros(n_ren,n_load,n_cont);
z1_risk_overall = zeros(n_ren,n_load);
z2_risk_overall = zeros(n_ren,n_load);
z3_risk_overall = zeros(n_ren,n_load);
z4_risk_overall = zeros(n_ren,n_load);
z5_risk_overall = zeros(n_ren,n_load);
stochastic_risk_cont = zeros(n_load,n_cont);
stochastic_risk_overall = zeros(n_load,1);
z1_stochastic_risk_overall = zeros(n_load);
z2_stochastic_risk_overall = zeros(n_load);
z3_stochastic_risk_overall = zeros(n_load);
z4_stochastic_risk_overall = zeros(n_load);
z5_stochastic_risk_overall = zeros(n_load);
% fault type: LLL = 3, LLG = 2, LL = 1, SLG = 0
p_A = [75;8.8; 10;6.2];
%% main loop starts for all loading
for load = 0:n_load-1
%calculate sigma of lamba for the first loading case only
if load==0
% read the contingency data
cont_data = xlsread('fault_rate.xlsx', 'lambda');
sigma_lambda = 0;
for cont = 1:n_cont
sigma_lambda = sigma_lambda + cont_data(cont,6);
end
end
if load > n_load/2
p_WTG = p2_WTG;
else
p_WTG = p1_WTG;
end
for ren = 0:n_ren-1
sim_data = [];
temp = strcat('sim_0_',num2str(100+load*5,'%d'),'_',num2str(ren*20,'%d'),'.m');
temp2 = strcat('summary_',num2str(100+load*5,'%d'),'_',num2str(ren*20,'%d'));
run(temp);
sim_data = [sim_data;eval(temp2)];
sim_data(:,4) = 0;
temp = strcat('sim_1_',num2str(100+load*5,'%d'),'_',num2str(ren*20,'%d'),'.m');
run(temp);
sim_data = [sim_data;eval(temp2)];
temp = strcat('sim_2_',num2str(100+load*5,'%d'),'_',num2str(ren*20,'%d'),'.m');
run(temp);
sim_data = [sim_data;eval(temp2)];
temp = strcat('sim_3_',num2str(100+load*5,'%d'),'_',num2str(ren*20,'%d'),'.m');
run(temp);
```

```
fix_data = eval(temp2);

sim_data = [sim_data;fix_data];
for cont = 1:n_cont
cont_type = cont_data(cont,1);
if cont_type ==1
n_loc = 3;
elseif cont_type ==2
n_loc = 2;
end
lambda = cont_data(cont,6);
p_E = (1 - exp(-lambda)) * exp(-sigma_lambda+lambda) / n_loc;
for fault_type = 0:n_fault-1
for loc = 0:n_loc-1
tvar = find(sim_data(:,3)==cont);
if n_loc == 3
tvar2 = find(sim_data(tvar,8)==loc/2);
elseif n_loc==2
tvar2 = find(sim_data(tvar,8) == loc);
end
tvar3 = find(sim_data(tvar(tvar2),4) == fault_type);
if (sim_data(tvar(tvar2(tvar3)),9)) > 5
impct  = (sim_data(tvar(tvar2(tvar3)),9));
else
impct = 0;
end
Impact = max(0,(sim_data(tvar(tvar2(tvar3)),11)-50))*(-c_orig+c_emerg)*10 +
c_load*impct;
z1_Impact = sim_data(tvar(tvar2(tvar3)),35)*(-c_orig+c_emerg)*10 +
c_load*sim_data(tvar(tvar2(tvar3)),40);
z2_Impact = sim_data(tvar(tvar2(tvar3)),36)*(-c_orig+c_emerg)*10 +
c_load*sim_data(tvar(tvar2(tvar3)),41);
z3_Impact = sim_data(tvar(tvar2(tvar3)),37)*(-c_orig+c_emerg)*10 +
c_load*sim_data(tvar(tvar2(tvar3)),42);
z4_Impact = sim_data(tvar(tvar2(tvar3)),38)*(-c_orig+c_emerg)*10 +
c_load*sim_data(tvar(tvar2(tvar3)),43);
z5_Impact = sim_data(tvar(tvar2(tvar3)),39)*(-c_orig+c_emerg)*10 +
c_load*sim_data(tvar(tvar2(tvar3)),44);
risk_cont(ren+1,load+1,cont) = risk_cont(ren+1,load+1,cont) +
(p_A(fault_type+1)/100)*(p_E)*Impact;
z1_risk_cont(ren+1,load+1,cont) = z1_risk_cont(ren+1,load+1,cont) +
(p_A(fault_type+1)/100)*(p_E)*z1_Impact;
z2_risk_cont(ren+1,load+1,cont) = z2_risk_cont(ren+1,load+1,cont) +
(p_A(fault_type+1)/100)*(p_E)*z2_Impact;
z3_risk_cont(ren+1,load+1,cont) = z3_risk_cont(ren+1,load+1,cont) +
(p_A(fault_type+1)/100)*(p_E)*z3_Impact;
z4_risk_cont(ren+1,load+1,cont) = z4_risk_cont(ren+1,load+1,cont) +
(p_A(fault_type+1)/100)*(p_E)*z4_Impact;
z5_risk_cont(ren+1,load+1,cont) = z5_risk_cont(ren+1,load+1,cont) +
(p_A(fault_type+1)/100)*(p_E)*z5_Impact;
risk_overall(ren+1,load+1) = risk_overall(ren+1,load+1) +
(p_A(fault_type+1)/100)*(p_E)*Impact;
z1_risk_overall(ren+1,load+1) = z1_risk_overall(ren+1,load+1) +
(p_A(fault_type+1)/100)*(p_E)*z1_Impact;
z2_risk_overall(ren+1,load+1) = z2_risk_overall(ren+1,load+1) +
(p_A(fault_type+1)/100)*(p_E)*z2_Impact;
z3_risk_overall(ren+1,load+1) = z3_risk_overall(ren+1,load+1) +
(p_A(fault_type+1)/100)*(p_E)*z3_Impact;
z4_risk_overall(ren+1,load+1) = z4_risk_overall(ren+1,load+1) +
(p_A(fault_type+1)/100)*(p_E)*z4_Impact;
z5_risk_overall(ren+1,load+1) = z5_risk_overall(ren+1,load+1) +
(p_A(fault_type+1)/100)*(p_E)*z5_Impact;

stochastic_risk_cont(load+1,cont) = stochastic_risk_cont(load+1,cont) +
p_WTG(ren+1)*(p_A(fault_type+1)/100)*(p_E)*Impact;
stochastic_risk_overall(load+1)=stochastic_risk_overall(load+1) +
p_WTG(ren+1)*(p_A(fault_type+1)/100)*(p_E)*Impact;
z1_stochastic_risk_overall(load+1)=z1_stochastic_risk_overall(load+1) +
p_WTG(ren+1)*(p_A(fault_type+1)/100)*(p_E)*z1_Impact;
```

```
z2_stochastic_risk_overall(load+1)=z2_stochastic_risk_overall(load+1) +
p_WTG(ren+1)*(p_A(fault_type+1)/100)*(p_E)*z2_Impact;
z3_stochastic_risk_overall(load+1)=z3_stochastic_risk_overall(load+1) +
p_WTG(ren+1)*(p_A(fault_type+1)/100)*(p_E)*z3_Impact;
z4_stochastic_risk_overall(load+1)=z4_stochastic_risk_overall(load+1) +
p_WTG(ren+1)*(p_A(fault_type+1)/100)*(p_E)*z4_Impact;
z5_stochastic_risk_overall(load+1)=z5_stochastic_risk_overall(load+1) +
p_WTG(ren+1)*(p_A(fault_type+1)/100)*(p_E)*z5_Impact;
clc;
LOADING = load*5+100
RENEWABLE = ren*20
CONTINGECY = cont
FAULT_TYPE = fault_type
LOCATION = loc
IMPACT = Impact
RISK_CONT = risk_cont(ren+1,load+1,cont)
RISK_OVERALL  = risk_overall(ren+1,load+1)
end
end
end
end
end
%% plot highest risk contingency
highest_risk = zeros(n_load,n_cont);
z1_highest_risk = zeros(n_load,n_cont);
z2_highest_risk = zeros(n_load,n_cont);
z3_highest_risk = zeros(n_load,n_cont);
z4_highest_risk = zeros(n_load,n_cont);
z5_highest_risk = zeros(n_load,n_cont);
for k=1:n_cont
for j = 1:n_load
highest_risk(j,k) = max(risk_cont(:,j,k));
z1_highest_risk(j,k) = max(z1_risk_cont(:,j,k));
z2_highest_risk(j,k) = max(z2_risk_cont(:,j,k));
z3_highest_risk(j,k) = max(z3_risk_cont(:,j,k));
z4_highest_risk(j,k) = max(z4_risk_cont(:,j,k));
z5_highest_risk(j,k) = max(z5_risk_cont(:,j,k));
end
end
```

APPENDIX H

MATLAB CODE FOR PLOTTING EQUAL AREA CRITERION IN CHAPTER 6

```
clear all;
close all;
%% case 1
delta = 0:0.01:pi;
pM_pre = 2.254;
pM_fault = 0.3217;
pM_post = 1.61;
Pe_prefault = pM_pre*sin(delta);
Pe_fault = pM_fault*sin(delta);
Pe_postfault = pM_post*sin(delta);
pm = 1.0;
r1 = pM_fault/pM_pre;
r2 = pM_post/pM_pre;
d0 = asin(pm/pM_pre);
dm = pi - asin(pm/(r2*pM_pre));
delta_critical  = 1.20;
pm = 1.0 + 0* delta;
Y1 = pm - Pe_fault;
Y2 = Pe_postfault - pm;
loc0 = find(abs(delta-d0)<0.01);
loc1 = find(abs(delta-delta_critical)<0.01);
loc2 =find(abs(delta-dm)<0.01);
a1 = trapz(delta(loc0(1):loc1(1)),Y1((loc0(1):loc1(1))))
a2 = trapz(delta(loc1(1):loc2(1)),Y2((loc1(1):loc2(1))))
subplot(2,1,1)
hold on;
plot(delta, Pe_prefault)
plot(delta, Pe_fault)
plot(delta, Pe_postfault)
plot(delta, pm)                  %#create second curve
X=[delta(loc0(1):loc1(1)),fliplr(delta(loc0(1):loc1(1
Y=[Pe_fault(loc0(1):loc1(1)),fliplr(pm(loc0(1):loc1(1)))];
fill(X,Y,'--','FaceAlpha', 0.4);
X=[delta(loc1(1):loc2(1)),fliplr (delta(loc1(1):loc2(1)))];
Y=[pm(loc1(1):loc2(1)),fliplr(Pe_postfault(loc1(1):loc2(1)))];
fill(X,Y,'--','FaceAlpha', 0.4);
%% case 2
Istat_pre =1 ;
Istat_fault =0;
Istat_post =1;
x1 = 0.2;
x2_pre = 0.3;
x2_post= 0.5;
E = 1.127;
vr_pre = (1/(x1+x2_pre))*sqrt(E^2*x2_pre^2 + x1^2 + 2* E* x1*x2_pre.*cos(delta));
vr_fault    =    (1/(x1+x2_fault))*sqrt(E^2*x2_fault^2    +    x1^2    +    2*    E*
x1*x2_fault.*cos(delta));
vr_post = (1/(x1+x2_post))*sqrt(E^2*x2_post^2 + x1^2 + 2* E* x1*x2_post*cos(delta));
pm = 0.5;
p2M_fault = pM_fault;
p2M_pre  = (1+Istat_pre*(x1*x2_pre/(x1+x2_pre))./vr_pre)*E/(x1+x2_pre);
p2M_post = (1+Istat_post*(x1*x2_post/(x1+x2_post))./vr_post)*E/(x1+x2_post);
P2e_pre = p2M_pre.*sin(delta);
P2e_fault = Pe_fault;
P2e_post = p2M_post.*sin(delta);
pm = 0.5;
delta_critical2  = 2.139;
loc0 = find(abs(P2e_pre -pm)<0.01);
loc2 = max(find(abs(P2e_post -pm)<0.01));
loc1 = find(abs(delta-delta_critical2)<0.01);
pm = 0.5 + 0* delta;
Y1 = pm - P2e_fault;
Y2 = P2e_post - pm;
a3 = trapz(delta(loc0(1):loc1(1)),Y1((loc0(1):loc1(1))))
a4 = trapz(delta(loc1(1):loc2(1)),Y2((loc1(1):loc2(1))))
subplot(2,1,2)
plot(delta, P2e_pre,'-')
hold on;
plot(delta, P2e_fault,'-')
plot(delta, P2e_post,'-')
```

```
plot(delta, pm)
set(gca,'xticklabel', '0  \pi/4  \pi/2 \3pi/4 \pi ');
X=[delta(loc0(1):loc1(1)),fliplr(delta(loc0(1):loc1(1)))];
Y=[P2e_fault(loc0(1):loc1(1)),fliplr(pm(loc0(1):loc1(1)))];
fill(X,Y,'--','FaceAlpha', 0.4);
X=[delta(loc1(1):loc2(1)),fliplr(delta(loc1(1):loc2(1)))];
Y=[pm(loc1(1):loc2(1)),fliplr(P2e_post(loc1(1):loc2(1)))];
fill(X,Y,'--','FaceAlpha', 0.4);
legend([P2e_pre   P2e_fault   P2e_post   pm],{'P_{pre-fault}','P_{fault}',   'P_{pre-
postfault}','P_{mechanical}'});
```

APPENDIX I

R CODES FOR RBSA DIAGNOSTICS TOOL

```
#
# This is the server logic of a Shiny web application. You can run the
# application by clicking 'Run App' above.
#
# RBSA Daignostics Tool
#
## load required libraries automatically and install if packages not
found
# define function usepackage to auto install packages/load libraries
usePackage <- function(p) {
  if (!is.element(p, installed.packages()[,1]))
    install.packages(p, dep = TRUE)
  require(p, character.only = TRUE)
}
usePackage("shiny")
usePackage("shinydashboard")
usePackage("ggplot2")
usePackage("dplyr")
usePackage("tidyr")
usePackage('rbokeh')
usePackage('htmlwidgets')
usePackage("lubridate")
usePackage('scales')
usePackage("plot3D")
usePackage("threejs")
## load dashboard items from csv
# update this csv to add additional dashboards
setwd("D://sdatta9//Dropbox (ASU)//#Fall 2016//RBSAtool/")
v.caselist <- read.csv(file="csv/list_testcases.csv", header=TRUE,
sep=",")
v.toolslist <- read.csv(file="csv/list_tools.csv", header=TRUE,
sep=",")
v.sysrisk <- read.csv(file="csv/systemrisk.csv", header=TRUE, sep=",")

risk_metric <- data.matrix(v.sysrisk)
usePackage("plotly")
# volcano is a numeric matrix that ships with R

## risk contingency analysis
risk.cont <- array(0, dim = c(19,6,18))
require(xlsx)
for (k in 1:19){
  risk.cont[k,,] = as.matrix(read.xlsx("csv/risk_cont.xlsx", sheetName
= paste0("Sheet",k), header = F))
}
## cont list
cont.list = (read.xlsx("csv/cont_list.xlsx", sheetName =
paste0("Sheet","1"), header = T))
## load sim data
load("csv/sim_data.RData")
colnames(sim_data) <- c("load", "ren", "cont", "fault", "from", "to",
"ckt","loc", "loadloss", "genloss")
```

```
#
# This is the server logic of a Shiny web application. You can run the
# application by clicking 'Run App' above.
#
# RBSA Diagnostics- UserInterface (UI) Functions
#
#

usePackage("shiny")
usePackage("shinydashboard")

## Define UI for application that draws a histogram
# define theme option
dashboardPage(skin = "red",

  # Application title
  dashboardHeader(
           title = tags$h3("RBSA Diagnostics")
            ),
  # Define sidebar
  dashboardSidebar(
          # html style for dropdown menu
           tags$style(type='text/css', ".selectize-input { font-size:
18px; line-height: 24px;} .selectize-dropdown { font-size: 18px; line-
height: 24px; }"),
           # dropdown selection for dashboard
           # list loaded in global.r (line 18) from csv file
           selectInput("testcase",
                       h4("Select Test Case:"),
                       choices = as.character(v.caselist$TestSystems),
                       selected = v.caselist$TestSystems[1]),

           # Dynamic menu based on first dropdown box
           uiOutput("menu1"),
           uiOutput("menu2")
    ),

  ## Dashboard main panel / body design
  dashboardBody(
  # Dynamic maain panel based on input selection conditions
  uiOutput("plotrbsa"),

  conditionalPanel(condition=paste("input.testcase=='MiniWECC'"),
                    # define infobox header
                    infoBox(h3("Under Construction"),
                            paste(month.abb[month(Sys.Date()-
day(Sys.Date()))], year(Sys.Date()-day(Sys.Date())), sep=" "),
                            icon = icon("globe"),
                            fill = FALSE,
                            width = 12, color = "red"),

                    box(title = "Under Construction",
                        status = "primary",
                        solidHeader = TRUE,
                        collapsible = TRUE,
                        width = 12)
```

```
  ),
  conditionalPanel(condition=paste("input.testcase=='TestSystem-T1'"),
                # define infobox header
                 infoBox(h3("RBSA Contingency Ranking & Diagnos-
tics"),
                         paste(day(Sys.Date()),
month.abb[month(Sys.Date())], year(Sys.Date()), sep="-"),
                         icon = icon("line-chart"),
                         fill = FALSE,
                         width = 10, color = "green"),
                # define logo box
                box(
                  img(src='logo.png', align = "right"),
                  solidHeader = F,
                  collapsible = F,
                  width = 2),
                # define main panel content
                # Define tabs with tabpanel
                 tabsetPanel(

                  tabPanel(h4("RBSA"),


                    box(title = (paste("Risk metric", "\u03c1")),
                        status = "primary",
                        solidHeader = TRUE,
                        collapsible = TRUE,
                        width = 4,
                        dataTableOutput("risk_val")
                        ),
                    box(title = "Risk plot",
                        status = "primary",
                        solidHeader = TRUE,
                        collapsible = TRUE,
                        width = 8,
                        plotlyOutput("plotrisk",
                                     height = "480px"
                                     )
                        )
                  ),
                  tabPanel(h4("RBSA Contingency Analysis"),

                           box(title = (paste("Contingency Rank-
ing")),
                               status = "primary",
                               solidHeader = TRUE,
                               collapsible = TRUE,
                               width = 4,
                               dataTableOutput("cont.rank")
                           ),
                           box(title = "Contingency list",
                               status = "primary",
                               solidHeader = TRUE,
                               collapsible = TRUE,
                               width = 8,
                               dataTableOutput("cont.list")
```

```
                    )
            )
            ,
            tabPanel(h4("RBSA Impact Analysis"),

                    box(title = "Contingency Rank",
                        status = "primary",
                        solidHeader = TRUE,
                        collapsible = TRUE,
                        width = 4,
                        tableOutput("overall.risk"),
                        dataTableOutput("cont.rank2")
                    ),
                    box(title = "Impact Assessment A",
                        status = "primary",
                        solidHeader = TRUE,
                        collapsible = TRUE,
                        width = 4,
                        uiOutput("menu3"),
                        selectInput("fault.type",
                                    h5("Select fault type:"),
                                    choices = as.charac-
ter(c("LLL","LLG","LL","SLG")),
                                    selected = "LLL"),
                        selectInput("fault.loc",
                                    h5("Select fault loc:"),
                                    choices = as.charac-
ter(c("NearEnd","FarEnd","Center")),
                                    selected = "NearEnd"),
                        dataTableOutput("impact.assessment")
                    ),
                    box(title = "Impact Assessment B",
                        status = "primary",
                        solidHeader = TRUE,
                        collapsible = TRUE,
                        width = 4,
                        uiOutput("menu4"),
                        selectInput("fault.type2",
                                    h5("Select fault type:"),
                                    choices = as.charac-
ter(c("LLL","LLG","LL","SLG")),
                                    selected = "LLL"),
                        selectInput("fault.loc2",
                                    h5("Select fault loc:"),
                                    choices = as.charac-
ter(c("NearEnd","FarEnd","Center")),
                                    selected = "NearEnd"),
                        dataTableOutput("impact.assessment2")
                    )

            )
          )
  )
)
)
```

```
#
# This is the server logic of a Shiny web application. You can run the
# application by clicking 'Run App' above.
#
# RBSA Diagnostics - Server Functions
#

usePackage("shiny")
usePackage("dplyr")

# Define server logic required for dashboard
shinyServer(function(input, output) {
  # selected dashboard reactive variable
  v.tools <- reactive({
    input$testcase
  })

  output$menu1 <- renderUI({
    if(v.tools() == "TestSystem-T1"){
      sliderInput("loading", h4("Loading above base case (%)"), min =
100, max=185, value = 180, step = 5)
    }
  })
  output$menu2 <- renderUI({
    if(v.tools() == "TestSystem-T1"){
      sliderInput("renewable", h4("Renewable gen (MW)"), min = 0,
max=1680, value = 336, step = 336)
    }
  })

  load.level <- reactive({
    input$loading
  })
  renewable.level <- reactive({
    input$renewable
  })
  risk.level <- reactive({
    risk_metric <- v.sysrisk[[(load.level()-100)/5+1]][[renewa-
ble.level()/336+1]]
    return(round(risk_metric,digits = 2))
  })

  risk.table <- reactive({
    data.frame(Loading_level = c("(%)",as.character(load.level())),
               Renewable   = c("(MW)",as.character(renewable.level())),
               Risk_metric = c(paste0("\u03c1"),as.charac-
ter(risk.level()))
              )
  })

  overall.risk.val <- reactive({
```

```
    data.frame(Overall_Risk_metric = as.character(risk.level())
    )
  })
  output$risk_val <- renderDataTable(
    risk.table(),
     options = list(searching = FALSE, paging = FALSE)

  )
  scene=list(camera=list(eye=list(x=-1.75,y=-1.55,z=.2)))
  axis_template2<- list(
    showgrid =TRUE,
    zeroline =TRUE,
    nticks = 10,
    showline =TRUE,
    title = '\u03c1'
    )
  axis_template1 <- list(
    showgrid =TRUE,
    zeroline =TRUE,
    nticks = 6,
    showline =TRUE,
    title = 'AXIS',
    mirror = 'all')
  output$plotrisk <- renderPlotly({
    Loading_pct = seq(100,185, by = 5)
    Renewable = seq(0,1680, by =372)

    plot_ly(z = ~risk_metric , x= ~Loading_pct, y = ~Renewable, type =
'surface') %>% add_surface() %>% layout(scene=scene, title = "Overall
Risk Mesh plot", xaxis = axis_template1, yaxis =axis_template1, zaxis =
axis_template2)
  })

  ## render cont list
  output$cont.list <- renderDataTable(cont.list)

  ## render cont rank

  cont.ranklist <- reactive({
    temp <- data.frame(risk.cont[,renewable.level()/336+1,
(load.level()-100)/5+1]) %>% mutate(Contingency = seq(1:19))
    colnames(temp) <- c("Risk_metric","Contingency")
    temp <-temp  %>% dplyr::arrange(-Risk_metric) %>% dplyr::mu-
tate(Risk_metric  = round(Risk_metric, digits = 2))
    return (temp)
  }

  )
  output$cont.rank <- renderDataTable(cont.ranklist(),
                                      options = list(searching = FALSE,
pageLength = 10))
  output$cont.rank2 <- renderDataTable(cont.ranklist(),
                                       options = list(searching =
FALSE,  pageLength = 10))
```

```
  critical.cont <- reactive(cont.ranklist() %>% dplyr::filter(Risk_met-
ric > 0) %>% select(Contingency))

  # ui output menu 3
  output$menu3 <- renderUI({

     if(nrow(critical.cont()) > 0){
      selectInput("v.critical", h4("Select critical contingency:"),
(critical.cont()), selected = (critical.cont())[1])
    }
  })
  output$menu4 <- renderUI({

    if(nrow(critical.cont()) > 0){
      selectInput("v.critical2", h4("Select critical contingency:"),
(critical.cont()), selected = (critical.cont())[1])
    }
  })
  output$overall.risk <- renderTable({
    overall.risk.val()
  })

  v.fault.type = reactive({
  if(input$fault.type == "LLL")
    return(3)
  else if(input$fault.type == "LLG")
    return(2)
  else if(input$fault.type == "LL")
    return(1)
  else if(input$fault.type == "SLG")
   return(0)
})
  v.fault.type2 = reactive({
    if(input$fault.type2 == "LLL")
      return(3)
    else if(input$fault.type2 == "LLG")
      return(2)
    else if(input$fault.type2 == "LL")
      return(1)
    else if(input$fault.type2 == "SLG")
      return(0)
  })

  v.fault.loc = reactive({
    if(input$fault.loc == "NearEnd")
      return(0)
    else if(input$fault.loc == "FarEnd")
      return(1)
    else if(input$fault.loc == "Center")
      return(0.5)
  })

  v.fault.loc2 = reactive({
    if(input$fault.loc2 == "NearEnd")
      return(0)
    else if(input$fault.loc2 == "FarEnd")
```

```
      return(1)
    else if(input$fault.loc2 == "Center")
      return(0.5)
  })

  v.critical.cont <- reactive((input$v.critical))
  v.critical.cont2 <- reactive((input$v.critical2))
  v.fault_rate <- reactive({
    temp <- cont.list %>% dplyr::filter(Cont == v.critical.cont()) %>%
dplyr::select(FaultRates)
    return(temp$FaultRates)
  })
  v.fault_rate2 <- reactive({
    temp <- cont.list %>% dplyr::filter(Cont == v.critical.cont2()) %>%
dplyr::select(FaultRates)
    return(temp$FaultRates)
  })
  impact.data <- reactive({
    temp <- sim_data %>% dplyr::filter(load == load.level(), ren == re-
newable.level()/1680*100, cont == v.critical.cont(), fault ==
v.fault.type(), loc == v.fault.loc()) %>% dplyr::mutate(
      loadloss = round(loadloss, digits = 1), genloss = round(genloss,
digits = 1)
    )
    temp <- temp %>% select (loadloss, genloss) %>% rename(Load.Loss.MW
= loadloss)  %>% rename(Generator.Loss.MW = genloss)
    temp2 <- temp[1,]
    temp2 <- temp2 %>% mutate(FaultRate = round(v.fault_rate(), digits
= 5))
    return (temp2)
    })

  impact.data2 <- reactive({
    temp <- sim_data %>% dplyr::filter(load == load.level(), ren == re-
newable.level()/1680*100, cont == v.critical.cont2(), fault ==
v.fault.type2(), loc == v.fault.loc2()) %>% dplyr::mutate(
      loadloss = round(loadloss, digits = 1), genloss = round(genloss,
digits = 1)
    )
    temp <- temp %>% select (loadloss, genloss) %>% rename(Load.Loss.MW
= loadloss)  %>% rename(Generator.Loss.MW = genloss)
    temp2 <- temp[1,]
    temp2 <- temp2 %>% mutate(FaultRate = round(v.fault_rate2(), digits
= 5))
    return (temp2)
  })

  output$impact.assessment <- renderDataTable(impact.data(),
                                              options = list(searching
= FALSE, paging = FALSE))

  output$impact.assessment2 <- renderDataTable(impact.data2(),
                                              options = list(searching
= FALSE, paging = FALSE))
  })
```