# COMPREHENSIVE RISK ASSESSMENT FOR RELIABLE POWER SYSTEM OPERATION

A Thesis Submitted to the College of

Graduate and Postdoctoral Studies

In Partial Fulfillment of the Requirements

For the Degree of Master of Science

In the Department of Electrical and Computer Engineering

University of Saskatchewan

Saskatoon, Canada

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## ABSTRACT

Rising uncertainty in power systems due to different system and operational requirement has led to increasing risks in the system operation. There are growing concerns with the widely used methods, such as the N-1 criterion, to determine operating reserve requirement during unit commitment, and the economic load dispatch method to allocate regulating margin to respond to disturbances. These deterministic methods do not consider the stochastic nature of power systems and are often inadequate to maintain the required operating reliability. This thesis introduces a comprehensive operating risk index, designated as the committed generators' response risk (CGRR) that can be used to maintain a specified level of operating reliability. An analytical probabilistic method to evaluate the CGRR is presented and validated using a Monte Carlo simulation technique. An application of the new index and the methodology is illustrated using the IEEE RTS system. The evaluation of CGRR provides a comprehensive operating risk of the scheduled generation until further assistance is available to the system and, therefore, helps operators in decision making for unit commitment and dispatch of the generating units to meet the projected load in the short future time.

There is an increasing trend of wind energy integration to the existing power system for its environmental benefits. But the wind power can create more challenges to the modern power systems due to possible wind disturbances. To appropriately quantify the wind variability, a short term wind power disturbance model is proposed by utilizing conditional probability approach. The information on operating risk of a wind connected power system can help operators to act prudently while operating a power system in a reliable manner. The developed CGRR based operating strategies can be used to continuously track the system risk level and take necessary actions before the undesirable consequences occurs.

## ACKNOWLEDGEMENTS

I would like to express my deepest gratitude to my supervisor Dr. Rajesh Karki for his invaluable guidance, continuous support and constant encouragement throughout this research work and in the preparation of this thesis. I am extremely thankful for his valuable time, pioneer ideas and extensive expertise to make my graduate studies meaningful and productive.

I appreciate the financial assistance provided by the College of Graduate and Postdoctoral Studies, the Department of Electrical and Computer Engineering and Natural Sciences and Engineering Research Council of Canada (NSERC) throughout my M.Sc. program.

I would also like to thank Dr. Sherif O. Faried and Dr. Ramakrishna Gokaraju for strengthening my knowledge on power systems through the related graduate courses. I am very thankful to my friend and colleague Dr. Suman Thapa for his valuable help and suggestions on my research as well as on other occasions. I thankfully acknowledge the help from all my colleagues in the power system research group, University of Saskatchewan.

I am grateful to my parents for their support and encouragement for my graduate studies. Last, but not the least, I would like to thank to my wife Riti and son Riyan for their constant encouragement, motivation and patience.

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| | |
|---|---|
| ARIMA | Auto Regressive Integrated Moving Average |
| ARMA | Auto Regressive Moving Average |
| CGRR | Committed Generators' Response Risk |
| COPT | Capacity Outage Probability Table |
| ELD | Economic Load Dispatch |
| GW | Gigawatt |
| HL I | Hierarchical Level I |
| HL II | Hierarchical Level II |
| HL III | Hierarchical Level III |
| IEEE | Institute of Electrical and Electronics Engineers |
| IEEE-RTS | IEEE Reliability Test System |
| IWP | Initial Wind Power |
| MCR | Maximum Continuous Rating |
| MCS | Monte Carlo Simulation |
| MW | Megawatt |
| NREL | National Renewable Energy Laboratory |
| NWP | Numerical Weather Prediction |
| ORR | Outage Replacement Rate |
| PJM | Pennsylvania-New Jersey-Maryland |
| RM | Regulating Margin |
| RR | Response Risk |
| UC | Unit Commitment |
| UCR | Unit Commitment Risk |
| WCS | Wind Energy Conversion System |
| WPD | Wind Power Disturbance |
| WTG | Wind Turbine Generator |

# 1 INTRODUCTION

## 1.1 Reliability Evaluation of Power System

Power system, in general, consists of generation, transmission and distribution infrastructures for the purpose of supplying electrical energy to consumers. Consumers need reliable power supply because disturbances in the service can cause considerable economic impacts. A power system is said to be reliable if it is operated maintaining an acceptable risk criterion during the considered time frame. It is also a fact that power system cannot be made completely reliable because of random failures of system components. With proper design consideration and investment on the infrastructure and operational methods, it is possible to improve the reliability of a power system. However, there is a limit to which investment can be made so that the incremental reliability benefit will be justified by the additional investment cost. Power system reliability studies are very useful in the decision making process as reliability and cost issues often conflict with each other.

System adequacy assessment and system security assessment shown in Figure 1.1 are the two fundamental evaluations that are generally performed in power system reliability studies [1]. System adequacy study is conducted to access whether or not there is sufficient infrastructure facilities such as generation, transmission and distribution available to supply the projected consumer demand for the time period considered. It is performed during the planning phase. System security study, on the other hand, is related to the study of power system operation where dynamic behaviors caused by minor or major disturbances are considered. The power system is said to be secure if it is capable of responding to such disturbances and maintain acceptable operational reliability.

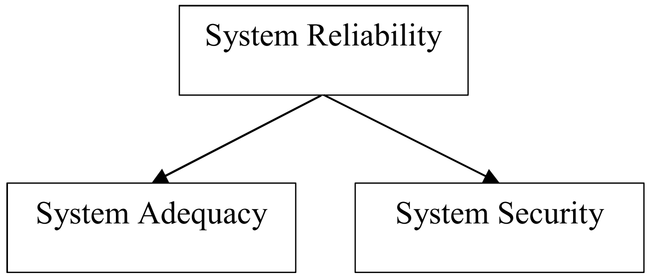


Figure 1.1: Sub division of system reliability.

Power system reliability study is generally carried out by dividing the entire system into three hierarchical zones named HL I, HL II and HL III [1] shown in Figure 1.2. HL I study does not include the transmission and distribution systems in the evaluation. The analysis in HL I is carried out to access the generation facility needed to sufficiently satisfy the total system load. In the HL II study, both the generating and transmission systems are taken in to consideration and examined whether the demands on the major load points within the power network are satisfied. HL III study includes all generation, transmission and distribution systems. The work presented in this thesis is focused on reliability evaluation at the HL I level in the power system operating domain.

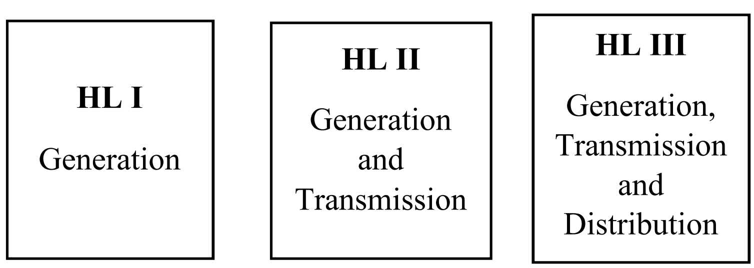


Figure 1.2: Power system in different hierarchical zones.

There are two main techniques applied in power system reliability evaluations: deterministic and probabilistic methods. Traditionally, power system reliability has been evaluated in a deterministic way, such as the N-1 criterion or a fixed percentage of peak load [1]. System evaluation using deterministic technique is very simple and frequently used [2, 3].

However, deterministic methods do not consider the stochastic nature of unit failures and load variations, which can greatly influence the overall system reliability. Consequently, probabilistic techniques have been developed to access the actual system risk. This research work utilizes a probabilistic technique to access power system operational reliability.

Probabilistic risk assessment can be conducted using either analytical methods or Monte Carlo simulation (MCS) [1]. In an analytical method, power system components are modeled by mathematical expressions and direct numerical solutions to calculate reliability indices. However, this method often requires approximations based on practical assumptions in the development of the analytical models. When the number of system components increases, the analytical method can become unrealistic due to the complexity of system modeling and possible errors due to the approximations. In such situations, MCS becomes more effective as it replicates the stochastic behavior of the real system and requires fewer approximations as compared to the analytical method. But the simulation technique also becomes computationally challenging in the operating domain as it requires large computation time to obtain reasonably accurate results. Another concern with the practical application of a MCS technique is that specific software is generally needed for the particular system, and changes to the software would be needed as the system changes or new scenarios evolve over time. This research work uses both the analytical and MCS techniques. A new analytical technique for operating reliability is developed in this research work. Also a MCS program is developed to validate the analytical model.

## 1.2 Operating Reserve and Reliable Power System Operation

The total generation capacity should always be equal to the sum of system load and losses at every instant of a power system operation. However, the stochastic nature of system component failures and/or load or generation variations cause disturbances that create challenges to continuously match the generation to the demand. For any kind of disturbance, such as a generating unit outage, the remaining heathy online units have to respond quickly to fulfill the lost power in order to maintain the balance between the supply and demand. At the instant of a power source failure, the inertial response of the online synchronous machines comes in effect which essentially provides energy to the power network by slowing down the rotational speed or the frequency [4]. Some frequency responsive load plays a positive role to arrest this frequency decline by reducing their consumption, but this does not bring frequency back to the scheduled or nominal value [5]. The system frequency should be restored very quickly, otherwise the power system becomes very vulnerable due to the decreased security margin. Therefore an appropriate amount of operating reserve needs to be maintained throughout the system operation which can be deployed immediately so that system frequency stays within the normal range even after a contingency occurs. This type of reserve is termed regulating margin and is defined as the net change on generation that can be made within a small margin time [6]. Power system operational reliability therefore highly depends on the operator's decision of unit commitment and operating reserve allocation among the committed units. Improper operational decision may end up with non-deployable reserve and, ultimately, the system may experience an undesired situation.

## 1.3 Wind Integrated Power System Operation

Conventional generating systems which utilize fossil fuel have adverse impact on the environment due to greenhouse gas emissions. It is also known that the stock of fossil fuel is being depleted and subject to frequent price variations. Additionally, there are growing concerns over the use of nuclear fuel because of the safety issues which are supported by different incidents that occurred around the globe in the past years. This has led the utilization of renewable energy resources such as wind and solar energy. Many nations have agreed to adopt the Renewable Portfolio Standard [7] to maintain a certain percentage of renewable energy share in the total energy consumption within a prescribed time frame. Wind energy is a promising renewable source to achieve this goal. With a well-developed technology and widely available resource, it is expected that a lot of wind generators will be connected to the grid in the near future. Global installed capacity of wind power reached 369.6 GW [8] in 2014. Wind capacity growth in Canada is around 23% on average annually over the past five years, and the present installed capacity has reached 11,205 MW [8]. This accounts for approximately 5% of Canada's total electricity generation. This proportion is still considered to be on the safe side for reliable system operation. However, the global trend shows that wind power may take an increasing share of power production in the very near future, and this causes serious concerns about reliable system operation.

From the system operation point of view, the highly variable nature of wind power creates a big challenge for operating reserve management, especially when the wind penetration becomes significant. As the trend shows, it is likely that the conventional environmentally unfriendly generating stations will be gradually replaced by wind power. This reduces both the system inertial response and the operating reserve handling capability of power systems. The systems will likely need more operating reserve to accommodate wind generation despite the reduced reserve carrying capacity due to decreased penetration of conventional generation.

## 1.4 Problem Statement and Research Objectives

Generating units operating in a power system can fail at any time and the system load can also vary randomly. Power system operators are under constant pressure to arrive at the proper operating decisions due to unpredictable system parameters. An important task in power system operation is the short term load forecast. According to the predicted load, operators need to decide how many and which units to schedule to serve the expected demand for a certain time in the future, known as the lead time. The appropriate amount of operating reserve needs to be determined to address possible disturbances in the power system operation. Assigning a high amount of operating reserve results in increased system reliability, but it will also increase the unit price of electricity. On the contrary, a low amount of reserve will lower the operating cost, but may be insufficient to maintain the acceptable system reliability. The goal of the system operators is to provide reliable power supply as economical as possible at all times. The conventional approach is to maintain an operating reserve at least equal to the largest operating unit [1] and is known as the N-1 approach. But, this technique does not recognize the actual system risk as it ignores the stochastic nature of unit failures and load variations. As the N-1 criterion gives only a limited information of security level of a power system [9], the operating decisions using this criterion may yield over scheduling or under scheduling of generating units and there is a great chance of violation of economic and/or reliability constraints in power system operation [1]. In other words, determination of operating reserve margins based on the deterministic approach can lead to inefficient and costly resource allocation [10].

The concerns highlighted in the preceding paragraph have led to research and development of probabilistic methods that can incorporate the uncertainties in system operation and provide proper evaluation of system operating risks. Probabilistic methods or risk based techniques contain more information of system security level and can access the actual operating risk. Many publications listed in [11] provide the procedures of power system probabilistic security assessment. The Pennsylvania-New Jersey-Maryland (PJM) method presented in [12] is a pioneer work in applying probabilistic methods in operating reserve evaluation. A probability distribution of committed generation is created in this method as a function of the lead time. This is the exposure time of the operating condition within which additional capacity assistance will not be available. The unit commitment risk (UCR) index was introduced in [1] to quantify the operating risk associated with the unit commitment decision, which is the probability of the committed generation just meeting or failing to meet the load requirement. The PJM method was extended to incorporate rapid start units in [13] and import/export constraints in [14]. The technique was further developed in [15] for spinning reserve evaluation in composite power systems. A hybrid method proposed in [16] presents a probabilistic framework to evaluate the probabilities of finding the system in "healthy", "marginal" and "at risk" operating states that are classified using the N-1 deterministic criterion. This technique is utilized to assess spinning reserve requirements in wind connected power systems in [17]. The hybrid method is further modified in [18] for spinning reserve evaluation in a deregulated market.

Another important task of the system operator is to decide how to dispatch the scheduled units to meet the load and properly allocate the operating reserve among the generating units that are in operation. This is known as load dispatch. System operators commonly use an economic load dispatch (ELD) to minimize generation operating costs. As economy and reliability often compete with each other, the economic operating decision can lead to high operating risks. Probabilistic methods have also been developed to assess the risk associated with the allocation of the spinning reserve to the committed units with varying ramp rates and capacity constraints. The probability of failing to generate sufficient response capacity within the specified margin time to satisfy the load following a disturbance is termed as the response risk (RR) [2]. This index is utilized in [19] for advanced dispatch of spinning reserves. A hybrid method is presented in [3] for optimal distribution of spinning reserves in a generating system.

Modern power system operation has become more challenging by the integration of highly variable energy resources such as wind power. As the existing generators and loads are always random in nature, the wind power connection to the system adds one more stochastic element and complicates system evaluation. It is very challenging to determine appropriate operating reserve margins considering wind power generation because the output from the wind conversion system (WCS) is totally dependent on the wind speed which is unpredictable. As more wind power is connected to the system, it will constitute a large proportion of the operating capacity relative to the conventional generation. When wind speed suddenly drops or ceases entirely, the wind power output will drop significantly or become zero, and the deficit power needs to be fulfilled by the remaining conventional units in operation. The continuity of power supply in this case depends on the available operating margin in the conventional units. But as mentioned in section 1.3, wind power integration has already replaced some conventional units which would have carried some additional operating reserves. Thus power system operation becomes very complex after the connection of a variable generation. Deterministic approach to quantify the required operating reserve and access the operating risk in such situations could be highly erroneous and, as such, it requires risk based techniques for proper evaluation. Reference [21] reported a basic reliability evaluation technique for non-conventional energy such as wind or solar integrated generating system. UCR analysis of a wind integrated power system is presented in [17] which examined the operating performance in terms of contribution to load carrying capability. This study was further enhanced by [22] which utilized the area risk concept developed for reliability evaluation of rapid start and hot standby units. Dispatch decisions for wind connected power systems are illustrated in [23, 24] using hybrid techniques previously applied in [25].

Reported research on operating reliability using probabilistic methods treat unit commitment and load dispatch as separate operating tasks with different decision criteria. A UCR criterion based unit commitment may restrict a desired dispatch with non-deployable spinning reserve due to ramp rate constraints of the generating units that are not considered in the UCR evaluation. As the probability of power outage following a disturbance depends on risks associated with both of these tasks, a comprehensive risk index is necessary, and introducing such an index and its application in operating decisions are the primary objectives of this research work. The consideration of both scenarios – unit commitment and dispatch via a single risk index reflects the real world situation because in each operating condition, this process continuously monitors the availability of required regulating margin to address the possible disturbances and thus it can be utilized to track the system security. Additionally, an experimental model is also developed which utilizes a MCS technique to evaluate the proposed risk index. Although MCS method increases computational accuracy, it will not be practical to use this method for real time solutions due to its longer time requirement to solve the problem. MCS results are utilized to validate the results obtained from the analytical model. The next objective of this study is to utilize the proposed risk index for decision making scenarios of power system operation. The proposed technique gives an overall indication of operating condition of the scheduled generators and therefore is useful information. An application of the new index and methodology is illustrated using the IEEE RTS system [20,39], and the impact on operating reliability of major operating variables, such as, number and size of committed units, unit ramp rates, regulating margin, and reserve distribution are analyzed. Operating risk assessment and quantifying required operating reserve will become more complicated for the wind connected power system as wind resource variability is an additional stochastic element added to the system operation. Depending upon the wind penetration level and operating strategy, there might be a possibility of improving or degrading system reliability. To address this issue, developing an appropriate wind disturbance model is another objective of this thesis. Wind power model should capture the wind variability, which ultimately provides an indication of operating reserve requirement. An effort has been made to formulate a realistic wind power model from the available wind speed data. Further, the developed risk assessment model is extended for wind integrated power systems to access the operating. This model helps to quantify operating reserves requirement for a given wind penetration level.

The main objectives of this research work are summarized below:

- To develop a risk based approach to combine the unit commitment and load dispatch in operating risk assessment for conventional as well as wind connected power systems.
- To develop a probabilistic analytical model to evaluate comprehensive operating risk considering parameters such as number of units, unit capacities, ramp rates and failure rates.
- To develop a MCS model for comprehensive operating risk evaluation and use it to validate the analytical model.
- To develop an appropriate wind power disturbance model to capture wind variability.

- To develop power system operating techniques utilizing the proposed risk index and extend the developed methodology for application in wind connected power systems.

## 1.5 Thesis Organization

This thesis contains six chapters. Chapter 1 is an overview of reliability evaluation of power systems in the operating domain for both conventional and wind connected generating systems. This chapter also includes the research objectives of this thesis.

Chapter 2 describes basic concepts of operating risk assessment at the HL I level. An example system is presented to illustrate the analytical concept of operating risk assessment. The Monte Carlo Simulation approach for the operating reliability evaluation is also described.

Chapter 3 introduces a comprehensive risk index that combines the parameters for unit commitment and load dispatch, and provides a useful indicator for operating decisions. This new index attributes the both unit commitment and response risk for a given operating condition. The detail method with the suitable examples is presented. The obtained results are also validated by using Monte Carlo Simulation approach.

Chapter 4 presents case studies to illustrate the application of the proposed risk index. Starting with the economic load dispatch, a detail risk based load scheduling technique is presented. Different scenarios are shown that make clear to the operators for decision making on system operation.

Chapter 5 contains reliability evaluation of wind connected generating system. The first part proposes the wind power model which consists short term wind power forecast using conditional probability approach and WCS model suitable for risk evaluation of wind connected power system. The second part illustrates the procedure to utilize new risk index for different aspects of operation of wind connected generating system.

Chapter 6 provides the summary and conclusion of this research and concludes the thesis.

# 2 BASIC CONCEPTS OF POWER SYSTEM OPERATING RISK ASSESSMENT

## 2.1 Introduction

Electric power system is operated with generating capacity that is greater than the load demand in a normal operating condition. The extra generating capacity is required as an operating reserve to address abnormal situations that may arise due to the system component failures or the uncertainties in the demand. As the system load varies continuously, the scheduled generating capacity needs to be altered by re-scheduling of the online units or changing the unit commitment accordingly in order to maintain the balance between the demand and supply. Also, in each operating scenario, the system operators aim to minimize the cost of operation.

Power system operation broadly consists of two fundamental tasks. The first task is to determine the required number of generating units to be brought online to meet the anticipated load while meeting a required operating reliability criteria, such as the N-1 criterion. The next task is related to the decisions of assigning the appropriate amount of loading and reserve to these committed units in order to maintain continuity of service anticipating possible load variation or generation outage. The N-1 deterministic criterion is widely applied in utilities to determine the appropriate amount of operating reserve, which requires the operating reserve at least equal to the capacity of the largest operating generator in the system. This deterministic approach of allocating operating reserve to the generators based on the largest unit failure does not take considerations of the stochastic nature of component failures of the system and cannot provide consistent system operating risk. Probabilistic techniques of operating risk assessment have evolved to address this problem. In this chapter, fundamentals of probabilistic operating risk evaluation will be presented. Sample examples will be shown to illustrate the analytical evaluation procedures. The Monte Carlo Simulation technique will also be discussed.

## 2.2 Pennsylvania-New Jersey - Maryland (PJM) Method

The PJM method [12] was the first basic probabilistic method of determining spinning reserve requirement developed by Pennsylvania-New Jersey- Maryland interconnection in 1963. In this method, the probability of the committed generation just satisfying or failing to satisfy the projected system load is evaluated for a certain time in the future, termed as lead time [1]. The lead time is the time taken to bring an additional unit online to serve the load after a decision is made to start the unit. If any disturbance, such as a generating unit failure, occurs during the lead time, the continuity of the power supply depends upon the available generating capacity of the operating online units. The lead time may vary from a few minutes to several hours [1, 26] depending upon the unit type and rating. Although the system condition such as generators' status and load level are well known at the beginning of a system operation, the stochastic nature of generation failure and/or load variation can cause generation-load mismatch within the specified lead time. Therefore an appropriate system modelling is necessary to evaluate the operating risk considering both the unit commitment and load dispatch tasks in system operation.

## 2.3 Generating System Model

A Generating unit can be modeled by a simple 2 state Markov model, where the two states are the up or operating state and the down or failed state. With the assumption of exponential distributions of failure and repair times, the probability of a generating unit residing in an outage state after time T can be calculated using [27],

$$P(Down_j) = \frac{\lambda_j}{\lambda_j+\mu_j} - \frac{\lambda_j}{\lambda_j+\mu_j} e^{-(\lambda_j+\mu_j)T} \tag{2.1}$$

where $\lambda_j$ is the failure rate, $\mu_j$ is the repair rate for unit j and T is the time period considered. For the time period during which repairing of the unit is not possible, $\mu_j$=0. Thus the outage probability of a single committed unit is given by (2.2) [1] and is known as the outage replacement rate (ORR):

$$ORR_j = 1 - e^{-\lambda_j T_L} \simeq \lambda_j T_L \tag{2.2}$$

where, $T_L$ is the lead time.

A discrete cumulative distribution function F(Z) = P($Z_k$=1 to s) of s capacity outage states within the lead time $T_L$ can be obtained using (2.3) [1] to recursively calculate the cumulative probability of $Z_k$ MW outage in committed capacity.

$$P(Z_k) = (1 - ORR_j) \times P'(Z_k) + ORR_j \times P'(Z_k - C_j) \tag{2.3}$$

where Cj and ORRj are the capacity and ORR for TL lead time respectively of unit j added recursively to modify F(Z); P′(Zk) and P(Zk) are the cumulative probabilities of Zk capacity outage before and after adding the jth unit. Equation (2.3) is initialized by setting P′(Zk) =1 for Zk≤0 and P′(Zk) =0 otherwise [1].

### 2.3.1 Unit Commitment Risk Evaluation

Equation 2.3 is utilized to construct a generating capacity model for a particular operating condition. This model along with an appropriate load model can be utilized to evaluate the operating risk of a power system. Table 2.1 shows data on 6 generating units that are scheduled in an operating scenario of a hypothetical power system. The example system consists of four thermal units with higher failure rates and two hydro units. The total operating capacity is 360 MW. The generating system model in the form of a capacity outage probability table (COPT) is constructed using (2.3) and shown in Table 2.2. The ORR of the different units is calculated considering lead times of one and three hours.

Table 2.1: Unit parameters of the example system.

| Unit # | Type | Unit Capacity (MW) | Failure Rate (f/yr) | ORR | |
|---|---|---|---|---|---|
| | | | | Lead time= 1hr | Lead time= 3 hr |
| 1 | Thermal | 90 | 4 | 0.000456621 | 0.001369863 |
| 2 | Thermal | 90 | 4 | 0.000456621 | 0.001369863 |
| 3 | Thermal | 60 | 3 | 0.000342466 | 0.001027397 |
| 4 | Thermal | 60 | 3 | 0.000342466 | 0.001027397 |
| 5 | Hydro | 30 | 1 | 0.000114155 | 0.000342466 |
| 6 | Hydro | 30 | 1 | 0.000114155 | 0.000342466 |

Table 2.2: Generating system model.

| Capacity in (MW) | Capacity out (MW) | Cumulative Probability | |
|---|---|---|---|
| | | Lead time= 1hr | Lead time= 3 hr |
| 360 | 0 | 1 | 1 |
| 330 | 30 | 0.001825155 | 0.005467502 |
| 300 | 60 | 0.001597235 | 0.004786082 |
| 270 | 90 | 0.000913307 | 0.002740304 |
| 240 | 120 | 1.15906E-06 | 1.04182E-05 |
| 210 | 150 | 8.33657E-07 | 7.49654E-06 |
| 180 | 180 | 2.08752E-07 | 1.88326E-06 |
| 150 | 210 | 2.97421E-10 | 8.02493E-09 |
| 120 | 240 | 1.42813E-10 | 3.85609E-09 |
| 90 | 270 | 5.70472E-14 | 4.61894E-12 |
| 60 | 300 | 2.44556E-14 | 1.98121E-12 |
| 30 | 330 | 5.58274E-18 | 1.35645E-15 |
| 0 | 360 | 3.18668E-22 | 2.32309E-19 |

The unit commitment risk (UCR) is used as the risk index. The UCR is defined as the probability of the participating generators just supplying or failing the supply the projected system demand for the specified lead time [1]. The PJM method assumes a constant load for a specified lead time. It is assumed that the forecast load is 270 MW for the operating scenario given in Table 2.1 for the lead time of 1 or 3 hours. The operating reserve is 90 MW and equal to the capacity of largest operating unit. It can be seen From Table 2.2 that the UCR is 0.000913307 for lead time one hour and 0.002740304 for lead time three hours. The widely used deterministic

N-1 criterion does not recognize the change in operating risk as a function of the lead time. The UCR is very different and almost three times greater when the lead time is increased from one hour to three hours. If the operator wants to maintain the operating risk within a specified level, say UCR of 0.001, it is necessary to carry an operating reserve of 120 MW when the lead time is three hours. . The N-1 criterion provides excess operating reserve for a lead time of one hour, but is inadequate for a lead time of 3 hours. A UCR evaluation can be done to assess the operating reserve required to meet a specified risk criterion for an operating condition, and appropriate number of units from the priority loading order can be committed to obtain a risk based unit commitment.

## 2.4 Security Function Approach

The security function approach [28-30] is another way of evaluating the operating risk of a power system. Basically this technique uses a conditional probability approach [27] to evaluate the total system risk. This method covers a wide range of causes that can increase the system operating risk, such as shortage of spinning reserve, unaccepted voltage variation, system stability issues and other unwanted events in the system operation that can breach the overall operational security. The probability that the system security be violated is termed as the security function, and it varies as a function of time as shown in Equation 2.5.

$$S(t) = \sum_i P(t)\, Q(t) \qquad (2.5)$$

where, *P(t)* the probability that the system is in *i*th state at the time *t,*

*Q(t)* is the conditional probability that *i*th state breaches the system security at the time *t,* *S(t)* is the security function of time *t* and *i* includes the all possible system states

If the evaluation of security function is restricted to operating reserve only, the value of *Q(t)* becomes either 1 or 0 depending upon the operating reserve being available or unavailable. In this case, this method is identical with PJM method and shown by Equation 2.6 [1];

$$S(t) = \sum_i P(t) \tag{2.6}$$

where, $i$ includes only those states which breach the system security or which have no operating reserve, or the total output capacity is less or equal to the system demand, and $\sum_i P(t)$ is the cumulative probability of those capacity states breaching the security. *S(t)* is the UCR of the given operating condition for a lead time of *t*. Since this method requires enumerating all possible states, it can cause difficulty in computation if the system has large number of generating units. In such a case, it becomes reasonable to limit the number of contingencies by ignoring higher order contingencies with negligible probability. The security function approach was applied to evaluate UCR in the previous example system, and the results are tabulated in Table 2.3. The results are identical to those obtained using the PJM method.

Table 2.3: UCR evaluation by security function approach.

| Load (MW) | *S(t)*=UCR | |
|---|---|---|
| | Lead time= 1hr | Lead time= 3 hr |
| 330 | 0.001597235 | 0.004786082 |
| 270 | 0.000913307 | 0.002740304 |
| 240 | 1.15906E-06 | 1.04182E-05 |
| 210 | 8.33657E-07 | 7.49654E-06 |

## 2.5 Response Risk Analysis

The operating reserve and the number of generating units required to serve the forecast demand in an operating schedule within an acceptable risk can be determined by carrying out the unit commitment risk evaluation. There can be many possible ways in which the scheduled generating units can be loaded, and the operating reserve shared between the units. The UCR evaluation does not consider the task of allocating the load and spinning reserve to the committed generators. Also, the ramp rate capabilities of the generating units are not considered while evaluating UCR [1]. Generating units that have high ramp rates and that are operating with spinning reserve can respond very quickly to fulfill the power deficit created by a disturbance, such as an outage of a generating unit. The time taken to respond to a disturbance to mitigate power imbalance is very important for the stability and reliability of the operating condition. Reference [1, 31] state two concerned time periods termed margin time for which this response reserve is required: a shorter duration around 1 minute and a longer duration about 5-15 minutes. The shorter response is required to arrest the system frequency decline and maintain the tie line regulation. The longer response is needed to avoid emergency actions such as load curtailment. It means the system remains safe if necessary changes can be made within the margin time [26]. The response capacity that can be achieved by a scheduled generating unit within the margin time is known as the regulating margin or responding capability of the generator and is directly related to the ramp rate of the unit.

The response risk is the probability of not achieving the required response within the specified margin time [1]. It is necessary to take consideration of the ramp rate of the committed units and the individual unit failure rates in response risk evaluation as a unit can fail during the margin time while responding to a disturbance. The response risk evaluation technique is illustrated by considering the previous example system shown in Table 2.1. The ramp rates are shown in Table 2.4. The table shows that the hydro units have a higher ramp rate than the thermal units. Two possible operating conditions, designated as dispatch A and dispatch B are shown in Table 2.5 considering a load of 270 MW. All the six units carry spinning reserve in dispatch A. The spinning reserve is allocated to only three units in dispatch B. The unit commitment risk of the both the operating conditions are the same. The UCR is 0.000913307 for a lead time of one hour. The response capacity or the responding capability of dispatch A and dispatch B and the associated response risks are provided in Table 2.6.

If the risk of obtaining only 20 MW of response is considered, it is almost negligible (in the order of $10^{-18}$) for dispatch A while for dispatch B this value is 0.00020927, a significant risk. Furthermore it is possible that within 10 minutes dispatch A can survive a loss of 70 MW generation at a risk of 0.000304377, while dispatch B cannot survive even a loss of 30 MW generation. The reason of having good response in dispatch A is due to the distribution of the regulating margin to all the units. Additionally, the fast ramping hydro units are carrying most of the regulating margin in dispatch A, thus they are capable to ramp immediately. In dispatch B these units are fully loaded and thus cannot provide any regulating margin. This evaluation gives an idea of which unit to be operated in full capacity and which unit should have some head room for spinning reserve to minimize the operating risk.

Table 2.4: Response parameters of generating units in the example system.

| Type | Unit Capacity (MW) | Failure Rate (f/yr) | Ramp Rate (MW/min) | Probability of failure in 10 minutes |
|---|---|---|---|---|
| Thermal | 90 | 4 | 1 | 0.000076103501 |
| Thermal | 60 | 3 | 1 | 0.000057077626 |
| Hydro | 30 | 1 | 10 | 0.000019025875 |

Table 2.5: Two dispatch conditions of the example system.

| Unit # | Type | Unit Capacity (MW) | Dispatch A | | Dispatch B | |
|---|---|---|---|---|---|---|
| | | | Unit Loading (MW) | Regulating Margin (MW) | Unit Loading (MW) | Regulating Margin (MW) |
| 1 | Thermal | 90 | 70 | 10 | 50 | 10 |
| 2 | Thermal | 90 | 70 | 10 | 50 | 10 |
| 3 | Thermal | 60 | 55 | 10 | 50 | 10 |
| 4 | Thermal | 60 | 55 | 10 | 60 | 0 |
| 5 | Hydro | 30 | 10 | 20 | 30 | 0 |
| 6 | Hydro | 30 | 10 | 20 | 30 | 0 |
| Total | | 360 | 270 | 80 | 270 | 30 |

Table 2.6: Response risk evaluation.

| Dispatch A | | Dispatch B | |
|---|---|---|---|
| Response (MW) | Risk | Response (MW) | Risk |
| 80 | 1 | 30 | 1 |
| 70 | 0.000304377 | 20 | 0.00020927 |
| 60 | 3.80778E-05 | 10 | 1.44787E-08 |
| 50 | 1.04975E-08 | 0 | 3.30579E-13 |
| 40 | 3.62989E-10 | | |
| 30 | 9.64533E-14 | | |
| 20 | 9.56524E-18 | | |
| 10 | 4.18804E-22 | | |
| 0 | 6.83015E-27 | | |

## 2.6 Monte Carlo Simulation Technique

Monte Carlo Simulation (MCS) is a technique used in reliability evaluation which simulates the actual process and random behavior of system components. A series of experiments are simulated and the risk indices are found from the outcome of these experiments in the MCS method. The detailed procedure for applying MCS in power system reliability evaluations can be found in [32]. The MCS method requires more computational time than the analytical techniques. The computational time for the MCS method can be significant for highly reliable system or in instances involving very small risk values [33]. The main advantage of this method is that the results can be more accurate as this method requires less approximation than in the analytical method. The MCS method can easily generate the distribution of reliability indices [34] in addition to expected value, which can be valuable information in decision making. There are three types of MCS techniques that are applied in power system reliability evaluation; state duration sampling, state sampling and state transition sampling [32]. The first is a sequential technique and the remaining two are the non-sequential techniques. A brief description of these techniques is provided in the following sections.

### 2.6.1 State Duration Sampling Technique

This is a sequential method in which chronological state duration is sampled for all components by simulation [32]. The chronological system transition process is created by analyzing the status of the each component in the corresponding chronological order. The process involves the following 4 steps [32, 35]:

Step 1: Set the initial condition. It is usually assumed that all components are in their operating states at the beginning of the simulation process.

Step 2: Calculate the duration of the present state of each component using (2.9) before it transits to another state during its operation.

$$T_j = -\frac{1}{\lambda_j} \ln U_j \tag{2.9}$$

where, $T_j$ is the duration up to which j$^{th}$ component remains in its present state, $U_j$ is a uniformly distributed random number between 0 and 1, and $\lambda_j$ is either its failure rate or repair rate depending on whether the present state is the up state or the down state.

Step 3: Repeat step 2 after each component transits to a different state for the entire period of interest. The period of interest is unusually the lead time for the operating condition. Since the lead time is relatively short compared to the repair time of a generating unit, the repair process can be ignored in operating risk assessment. This process is done for all the components in the system.

Step 4: Identify the state of the system by combining the chronological transition states of all components throughout the period of interest. This completes one simulation cycle. The corresponding duration time for each component is recorded and it gives the chronological transition state of the system.

Step 5: Repeat steps 3 and 4 for many simulation cycles and record the system outage states. The risk indices are repeated by calculated after each simulation cycle. The process is repeated until the targeted convergence criteria for the calculated risk value is achieved.

The sequential simulation approach is utilized in this research work as it is very useful when the system operation in a current state depends on the previous state [36].

### 2.6.2 State Sampling Technique

The state sampling technique is a non-sequential simulation process where all the component states are sampled without considering chronology. The combination of all these component states determines the overall system state. A uniformly distributed random numbers between 0 and 1 is utilized to characterize individual component operating state [32]. This method can be applied to components that can reside in multiple states as well. Although this technique is comparatively simple, the correlation of events cannot be recognized using this method. The frequency index cannot be calculated as this approach does not recognize system state duration that is longer than the sample interval.

### 2.6.3 State Transition Sampling Technique

This technique is also a non-sequential process. The transition of the complete system is considered instead of the individual component states or component state transitions [37]. From this method, it is possible to calculate the frequency index without sampling distribution function and storing sequential information as needed in the state duration sampling technique. But this method can be used only if the component state duration follows the exponential distributions.

## 2.7 IEEE Reliability Test System (RTS)

The IEEE RTS [20, 39] is used as one of the test systems in this research. It represents a power system which consists of 32 generating units with different types of generation mix, i.e.

hydro, nuclear and. The capacity of the generating units varies from 12 MW to 400 MW. The total generating capacity and the annual peak load are 3405 MW and 2850 MW respectively. The operational, reliability and cost parameters of the IEEE RTS generating units, and their priority loading order are shown in Table 2.7.

Table 2.7: The IEEE RTS generation data.

| Loading Order | Type | Pg max (MW) | Pg min (MW) | Ramp Rate (MW/ min) | Failure Rate (occ/ yr) | Cost Parameters($/hr) | | |
|---|---|---|---|---|---|---|---|---|
| | | | | | | A | B | C |
| 1-4 | Hydro | 50 | 0 | 10 | 4.42 | 0 | 0.5 | 0 |
| 5-6 | Nuclear Stem | 400 | 200 | 0 | 7.96 | 216.576 | 5.345 | 0.00028 |
| 7 | Coal Steam | 350 | 150 | 9 | 7.62 | 388.25 | 8.919 | 0.00392 |
| 8-10 | Oil Steam | 197 | 80 | 6 | 9.22 | 301.223 | 20.023 | 0.003 |
| 11-14 | Coal Steam | 155 | 60 | 5 | 9.13 | 206.703 | 9.2706 | 0.00667 |
| 15-17 | Oil Steam | 100 | 40 | 3 | 7.3 | 286.241 | 17.924 | 0.0022 |
| 18-21 | Coal Steam | 76 | 25 | 2 | 4.47 | 100.439 | 12.145 | 0.01131 |
| 22-26 | Oil Steam | 12 | 5 | 1 | 2.98 | 30.396 | 23.278 | 0.13733 |
| 27-30 | Oil Combustions | 20 | 6 | 4 | 19.5 | 40 | 37.554 | 0.18256 |
| 31-32 | Hydro | 50 | 0 | 10 | 4.47 | 0 | 0.5 | 0 |

## 2.8 Conclusions

This chapter presents the basic concepts and essential techniques of power system operating risk evaluation. The PJM method is a pioneer technique for probabilistic operating risk assessment. The details of UCR assessment with a hypothetical example are presented in this chapter. An application of a UCR criterion to identify the number of generating units that are required to supply a projected demand for a specified future time period is illustrated. The fundamentals of the response risk evaluation are presented along with a sample application. The basic concept of the MCS approach is also discussed in this chapter as this method is utilized for model validation in this research work. The basic parameters of the IEEE RTS are described at the end of this chapter as this test system is used in the research work.

# 3 DEVELOPMENT OF A COMPREHENSIVE OPERATING RISK EVALUATION METHOD

## 3.1 Introduction

A power system must be operated to respond to the stochastic nature of system component failures and/or load variations to continuously match power supply to the total system demand in real time. For any kind of disturbance such as a generating unit outage, the healthy operating units must respond and fulfill the lost power within a specified response time to avoid load curtailment situations. The probability of such load curtailment situation depends on the probability and magnitude of power disturbances, amount of operating reserve in the system, ramp rates and responding capacity of the units carrying the reserve, and the lead time after which the system will receive further capacity assistance. A UCR based unit commitment may not always maintain enough system responding capability that can address the possible disturbances. This means UCR based decision cannot always provide enough system security as this procedure does not consider ramp rate constraints of the generating units. This chapter provides a concept of combining the unit commitment risk and response risk evaluation requirements to formulate a new comprehensive risk index designated as the committed generators' response risk (CGRR). A probabilistic analytical technique is developed to obtain this new risk index. A sequential MCS technique is also developed to simulate the operating conditions and obtain the CGRR index, and validate the results obtained from the analytical method. The CGRR value is evaluated for different loading conditions varying from light load to peak load scenarios in order to determine an acceptable risk level. This chapter also presents sensitivity studies of CGRR with unit failure rates and unit ramp rates of scheduled generating units in an operating condition.

## 3.2 Generating System Risk Assessment Model

Figure 3.1 shows the underlying concepts in the evaluation of the CGRR index. An operating condition has $m$ number of generating units committed for a lead time $T_L$. Forced outages of committed units can lead to load curtailment situations and are, therefore, considered as the major disturbance events in this research. $D_i$ is the disturbance associated with the $i^{th}$ event among the total $2^m$ contingencies, and $T_R$ is the response time within which the healthy generating units must respond with sufficient capacity to avoid load curtailment situation.

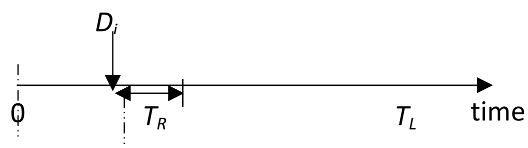

Figure 3.1: CGRR evaluation.

A capacity outage $Z_k$ due a major disturbance $D_i$ results in a reduction in operating capacity $X_k$ given by (3.1), where $N$ is the number of committed units on forced outage due the disturbance.

$$X_k = \sum_{j=1}^{N} C_{Lj} \tag{3.1}$$

The probability of capacity $X_k$ reduction can then be obtained from the discrete probability density function $f(Z) = p(Z_{k=1 \text{ to } s})$, where $p(Z_k) = P(Z_k) - P(Z_{k-1})$ and $P(Z_{k=1 \text{ to } s})$ can be found using (2.3) given in chapter 2. When a disturbance occurs resulting in capacity drop $X_k$, the healthy units carrying spinning reserve will respond to fulfill the capacity mismatch. The response capacity $C_{Rk}$ of the operating system in the response time $T_R$ is given by (3.2).

$$C_{Rk} = \sum_{j=1}^{m-N} c_{Rj} \tag{3.2}$$

where, $c_{Rj}$ is the response capacity of unit $j$ given by (3.3).

$$c_{Rj} = MIN(\gamma_j \times T_R, MCR_j - C_{Lj}) \qquad (3.3)$$

where, $\gamma_j$ and $MCR_j$ are the ramp rate and maximum continuous rating of unit j.

The response risk associated with capacity drop $X_k$ is the conditional probability given by (3.4).

$$RR \mid Z_k = 0 \text{ if } C_{Rk} > X_k$$

$$= 1 \text{ otherwise.} \qquad (3.4)$$

The CGRR can then be evaluated using a conditional probability approach as shown in (3.5) by aggregating the conditional response risk obtained in (3.4) weighted by the probability $p(Z_k)$ for all $s$ outage states in the discrete distribution $f(Z)$.

$$CGRR = \sum_{k=1}^{s} p(Z_k) \times RR|Z_k \qquad (3.5)$$

### 3.3 Illustration of the Proposed Method

The proposed methodology is illustrated in this section by application to a small generating system with 4 units committed for a lead time of 1 hour. The total rated capacity of the scheduled units is 100 MW and the load is 64 MW. The operating reserve is therefore 36 MW. Table 3.1 shows the MCR, failure rate λ, and ramp rate $\gamma$ of the generating units, and their loading capacity $c_L$ to meet the 64 MW load. It should be noted from Table 3.1 that the operating reserve of 36 MW is equal to the capacity of the largest unit. The unit commitment shown in Table 3.1, therefore, meets the N-1 criterion. The response capacity $c_R$ shown in the last column is calculated using (3.3) considering a response time $T_R$ of 10 minutes. The total response capacity is 30 MW. This will however be reduced when disturbances occur due to unit outages. .

Table 3.1: Generating unit parameters in the example system.

| Units $J$ | $MCR_j$ (MW) | Fail. Rate $\lambda_j$ (f/yr) | Ramp Rate $\gamma_j$ (MW/m) | Loading $C_{Lj}$ (MW) | Response Capacity $c_{Rj}$ (MW) |
|---|---|---|---|---|---|
| 1 | 20 | 1 | 2 | 7 | 13 |
| 2 | 36 | 1 | 1 | 20 | 10 |
| 3 | 11 | 1 | 1 | 4 | 7 |
| 4 | 33 | 1 | 1 | 33 | 0 |
| Total | 100 | | | 64 | 30 |

There exists $2^4 = 16$ contingences of unit outages considering 2-state generation models as shown in Table 3.2. The ORR for each unit in Table 3.1 is calculated using (2.2) for a lead time of 1 hour, and used in (2.3) to obtain the discrete probability distribution of capacity outages shown in the second and fourth columns of Table 3.2. The reduction in operating capacity $X_k$ obtained from (3.1) are shown in the third column, and system response capacities $C_{Rk}$ obtained from (3.2) on the fifth column of Table 3.2. The conditional response risk for each capacity outage condition shown in the sixth column are obtained using (3.4), and the CGRR shown at the bottom of the table is calculated using (3.5).

The obtained CGRR value of 0.00022837 is the total probability that generating units committed for the given operating decision will not be able to respond with adequate generation capacity to satisfy the system load within acceptable response time following major disturbance that can occur considering all contingencies of generation unit outages. It should be noted that this risk can be calculated prior to making the operating decision on unit commitment and load dispatch, and the risk can be varied by an alternate decision to meet an acceptable criterion.

Table 3.2: CGRR of 4 unit example.

| State $k$ | Outage MW $Z_k$ | Reduction MW $X_k$ | Probability $p(Z_k)$ | Response MW $C_{Rk}$ | $RR\| Z_k$ | $p(Z_k)\times RR\| Z_k$ |
|---|---|---|---|---|---|---|
| 1 | 0 | 0 | 0.9993152 | 30 | 0 | 0 |
| 2 | 11 | 4 | 0.0001141 | 23 | 0 | 0 |
| 3 | 20 | 7 | 0.0001141 | 17 | 0 | 0 |
| 4 | 31 | 11 | 1.30E-08 | 10 | 1 | 1.30E-08 |
| 5 | 33 | 33 | 0.0002282 | 30 | 1 | 0.0002282 |
| 6 | 36 | 20 | 0.0002282 | 20 | 0 | 0 |
| 7 | 44 | 43 | 2.61E-08 | 33 | 1 | 2.61E-08 |
| 8 | 47 | 24 | 2.61E-08 | 13 | 1 | 2.61E-08 |
| 9 | 53 | 40 | 2.61E-08 | 17 | 1 | 2.61E-08 |
| 10 | 56 | 27 | 2.61E-08 | 7 | 1 | 2.61E-08 |
| 11 | 64 | 44 | 2.97E-12 | 10 | 1 | 2.97E-12 |
| 12 | 67 | 31 | 2.97E-12 | 0 | 1 | 2.97E-12 |
| 13 | 69 | 53 | 5.21E-08 | 20 | 1 | 5.21E-08 |
| 14 | 80 | 57 | 5.95E-12 | 13 | 1 | 5.95E-12 |
| 15 | 89 | 60 | 5.95E-12 | 7 | 1 | 5.95E-12 |
| 16 | 100 | 64 | 6.79E-16 | 0 | 1 | 6.79E-16 |
| | | | | | CGRR = 0.00022837 | |

## 3.4 Contingency Orders in Analytical Method

The illustrative example in Table 3.2 considers only 4 committed units in the operating condition. The number of units can be quite large in a practical system operation which will result in a large number of contingency states and significantly increase computation burden. There will be a total of $2^m$ contingencies of generating unit outages in an operating condition consisting of m scheduled units considering a 2-state model of unit operation. The computation effort can be reduced by neglecting higher order contingencies that have very low probability of occurrence. Table 3.2 shows that states 11, 12, 14, 15 and 16 are associated with 3rd and 4th order contingencies involving outages of 3 and 4 units respectively within the exposure time. It can be noted that the CGRR will remain the same within 8 decimal places if these higher order states are not considered in the evaluation in Table 3.2.

A study was carried out considering different loading conditions of the IEEE RTS to determine an appropriate number of contingencies to be included in the CGRR evaluation in order to reduce computation effort while achieving reasonable accuracy. Table 3.3 shows seven operating schedules to meet the load ranging from 900 MW to 2459 MW. The appropriate numbers of units are committed from the priority loading order for each load condition to meet a probabilistic risk criterion of UCR < 0.001 [16]. The committed units are loaded using the economic load dispatch method. The CGRR was calculated in 11 decimal places considering all the contingency states and are shown in the 3$^{rd}$ column of Table 3.3. The table also shows the percent error when the number of contingencies in the evaluation is reduced. It can be seen that the error decreases as the order of the contingencies included in the evaluation is increased. The last column shows that there is no error when CGRR value is expressed in 11 decimal places, when contingencies up to the 4$^{th}$ order are considered in the evaluation. It can therefore be concluded that considering up to the fourth order contingency in CGRR evaluation provides acceptable results.

Table 3.3: Order of contingency states and accuracy in CGRR evaluation.

| Load (MW) | No. of units | CGRR×$10^6$ | Error (%) with included order of contingencies | | | |
|---|---|---|---|---|---|---|
| | | | $1^{st}$ | $2^{nd}$ | $3^{rd}$ | $4^{th}$ |
| 900 | 7 | 2686.33119 | 0.3476 | 3.8E-04 | 3.7E-07 | 0 |
| 1300 | 9 | 2685.91680 | 0.5419 | 1.3E-03 | 1.5E-06 | 0 |
| 1497 | 10 | 2688.12089 | 0.7280 | 1.9E-03 | 3.0E-06 | 0 |
| 1694 | 11 | 2691.40242 | 0.9524 | 3.1E-03 | 5.2E-06 | 0 |
| 2004 | 13 | 2701.18317 | 1.5167 | 6.2E-03 | 1.3E-05 | 0 |
| 2159 | 14 | 2707.68269 | 1.8555 | 8.3E-03 | 1.9E-05 | 0 |
| 2459 | 17 | 2725.82489 | 2.7522 | 1.5E-02 | 4.5E-05 | 0 |

### 3.5 Development of MCS Method for CGRR Evaluation

The sequential MCS approach is very useful while evaluating system operation that depends on time correlated factors [37]. For the complex operating conditions, analytical method may yield erroneous result due to the multiple approximations. In these scenarios MCS method is preferable, and can also be used to validate the analytical models. The conceptual procedure of the MCS technique is provided in section 2.6.1. In this method the times to failure of the committed generating units are assumed to follow an exponential distribution [32], and the repair of failed units during the short lead time $T_L$ is not considered. The operating time $T_i$ of the jth committed unit is estimated using (3.8):

$$T_j = -\frac{1}{\lambda_j}\ln\ U_j \tag{3.8}$$

where $\lambda_j$ is the failure rate of the ith generating unit, and $U_j$ is a uniformly distributed random number between 0 and 1 drawn to evaluate the operating time for the jth unit.

Unit $j$ is on outage at time $T_j$ if $T_j < T_L$. The system generation output or the loading capacity is less than the system load for the duration $T_L$ - $T_j$, and the remaining healthy units carrying spinning reserve ramp up to fulfill the capacity deficiency. The response capacity of the remaining healthy units in the response time, $T_R$ is calculated to determine if the reduction in loading capacity can be fulfilled by the response capacity. A response time of 10 minutes was considered in the study. The simulation run is flagged if the system response capacity fails to fulfill the capacity deficiency resulting in a load curtailment. If multiple outages occur within the lead time, the response capacity of the remaining healthy units in the response time is sequentially calculated after each disturbance. The CGRR index is calculated by dividing the number of flagged simulation samples by the total number of simulation runs. The simulations are repeated, and the CGRR is recalculated after each flagged sample. The difference in CGRR between consecutive calculations is monitored and the simulation is considered to be converged when the difference is within a specified criterion value. The criterion used in this study was a tolerance value of $10^{-09}$. Since the probability of generating unit outage in the short lead time is very small, the obtained CGRR values are very small. Therefore the MCS technique requires a large number of simulations in the range of $10^{10}$ before converging with reasonable accuracy in the results.

A study was also carried out to analyze the random number seeds, appropriate number of simulations required and the convergence criteria to be used to obtain the results with acceptable accuracy. The result of the MCS method varies depending upon the selection of the random number seed value. The CGRR of the example system in Table 3.1 was evaluated for a lead time of 1 hour and a response time of 10 minutes. Table 3.3 shows the results obtained using different random number seeds and convergence criteria.

Table 3.4: Monte Carlo results using different random number seeds and convergence criteria.

| Number of Simulations | Seed value | Convergence Criterion ($\leq$) | CGRR $\times 10^6$ |
|---|---|---|---|
| 270365429 | 1234321 | $10^{-09}$ | 228.2651 |
| 1746479739 | 1234321 | $10^{-10}$ | 228.0427 |
| 1065044911 | 45789 | $10^{-10}$ | 228.3105 |

The last two rows of Table 3.4 show the CGRR results using two different random number seeds when a tolerance of $10^{-10}$ was used as the convergence criterion. The difference in CGRR results is 2.678 $\times 10^{-07}$. This indicates that the inherent variability of the MCS technique limits the accuracy in the CGRR results to less than $10^{-08}$. A CGRR value in 6 decimal places is considered to be sufficient for practical purposes, and, therefore, the difference in results due to the selection of the random number seed is considered to be insignificant as they converge up to the sixth decimal place regardless of the selected seed number. Table 3.4 also shows that the number of simulations is increased by more than 6 folds when the convergence criterion is increased from $10^{-09}$ to $10^{-10}$. The convergence criteria used in this study is to stop the simulation if the CGRR value has variation within a tolerance difference of $10^{-10}$ for the 5 consecutive simulation results.

### 3.6 Validation of the Analytical Method Using MCS

The CGRR index calculated by the proposed analytical approach is compared with the result obtained by the MCS method developed for CGRR evaluation. Table 3.2 shows that the

CGRR of the example operating scenario calculated in six decimal points by the analytical method is 0.000228, and Table 3.4 shows that MCS method provides the same results using two different random number seeds. The results vary slightly after 6 decimal places.

Another study was carried out on the IEEE RTS to obtain the CGRR using both the analytical technique and the MCS method. The generator type, priority order, failure rate and the operating limits of the IEEE RTS are given in Table 2.7 in section 2.6. An operating condition is considered with a load of 1995 MW. Using the conventional N-1 unit commitment criteria, a total 13 number of generating units are committed from the priority loading order. An economic load dispatch by gradient method has been used to dispatch these units. Table 3.5 shows the unit ratings and loadings for this operating condition. It can be noted that the total committed capacity and the spinning reserve are 2406 MW and 411 MW respectively. The CGRR index obtained from the analytical technique is compared with the results obtained using the MCS method to validate the proposed analytical method.

Table 3.5: Operating condition under study.

| Unit # | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| MCR (MW) | 50 | 50 | 50 | 50 | 400 | 400 | 350 | 197 | 197 | 197 | 155 | 155 | 155 |
| Loading (MW) | 50 | 50 | 50 | 50 | 400 | 400 | 302 | 80 | 80 | 80 | 151 | 151 | 151 |
| RM (MW) | 0 | 0 | 0 | 0 | 0 | 0 | 48 | 60 | 60 | 60 | 4 | 4 | 4 |

The required simulation samples for convergence of the MCS technique are in the order of $10^{10}$ when a seed value of 45789 is considered with a convergence criterion of $10^{-10}$. The results obtained from the two methods are shown in Table 3.6. It can be seen that the results from the analytical method and MCS are very close. They are in fact equal in seven decimal places as shown in Table 3.6. The MCS method consumes significantly more time than the analytical method. The computation time can be very large in practical system evaluation, and therefore, the analytical method proposed in this work may be more readily applicable in practice.

Table 3.6: CGRR of the IEEE RTS, 13 unit case.

| CGRR | |
|---|---|
| Analytical Method | MCS |
| 0.00270118 | 0.00270114 |

## 3.7 Impact of Unit Ramp Rate and Failure Rate on CGRR

This section presents a study to evaluate the impact of generating unit ramp rate and the failure rate on the CGRR index. This is an important information for a power system operator to optimally schedule generating units in system operation. An example system operating condition consisting of seven generating units serving a load of 462 MW is considered in the study. The generating unit ratings and loading capacities are given in Table 3.7. It can be seen that the units are committed using the N-1 criteria. Three cases are considered with different unit ramp rates and failure rates to assess the impacts of these parameters on the CGRR. The ramp rate and failure rates of the scheduled units are 10 MW/minute and 4.42 occurrences/year respectively in Case A, which is considered as the base case. Case B has the same failure rate as the base case, but the unit ramp rate is reduced to 1 MW/minute. Case C has the same ramp rate as the base case, but the failure rate is increased to 7.62 occurrences/year. The spinning reserves and the regulating margins (RM) for a response time of 10 minutes for the three cases are also shown in Table 3.7.

Table 3.7: Example system operating condition considering 3 cases with different unit ramp rates and failure rates.

| Unit no. | Unit MCR (MW) | Unit Loading (MW) | Spinning Reserve (MW) | Case A | Case B | Case C |
|---|---|---|---|---|---|---|
| | | | | RM (MW) | RM (MW) | RM (MW) |
| 1 | 95 | 76 | 19 | 19 | 10 | 19 |
| 2 | 100 | 80 | 20 | 20 | 10 | 20 |
| 3 | 75 | 60 | 15 | 15 | 10 | 15 |
| 4 | 22 | 18 | 4 | 4 | 4 | 4 |
| 5 | 60 | 48 | 12 | 12 | 10 | 12 |
| 6 | 110 | 88 | 22 | 22 | 10 | 22 |
| 7 | 115 | 92 | 23 | 23 | 10 | 23 |

Case A: Ramp rate = 10 MW/min, Failure rate = 4.42 occ./yr

Case B: Ramp rate = 1 MW/min, Failure rate = 4.42 occ./yr

Case C: Ramp rate = 10 MW/min, Failure rate = 7.62 occ./yr

The proposed analytical method was used to evaluate the CGRR for the 3 case studies, and the results are shown in Table 3.8. The results indicate that Case B has the highest risk level, which is around 5 times than that of the base case. The ramp rate of the units in Case B is 10 times slower than that of the base case. The CGRR value for Case C is 1.7 times that of the base case even though the operating units have the same ramp rates as of the base case. This is due to the effect of the increased failure rates of the operating units in Case C.

Table 3.8: CGRR results for the three cases in Table 3.7.

| Case | Spinning Reserve (MW) | RM (MW) | CGRR $\times 10^{-6}$ |
|---|---|---|---|
| A | 115 | 115 | 507.8701 |
| B | 115 | 64 | 2520.5404 |
| C | 115 | 115 | 879.6700 |

A similar type of study was conducted considering a load of 1995 MW in the IEEE RTS with the operating condition given in Table 3.5. The failure rates and the ramp rates of the generating units are provided in Table 2.7. The sensitivity in CGRR was examined by considering 4 specific cases, Case 1 to Case 4. Case 1 is the base case using the IEEE RTS generating unit data. The failure rates of the scheduled units are doubled in Case 2. The ramp rates of the operating units are doubled in Case 3, while keeping the failure rates the same as in the base case. In Case 4, the both failure rates and ramp rates are doubled when compared to the base case. The CGRR are evaluated for the 4 cases and shown in Figure. 3.2.

Figure 3.2 shows that CGRR increases significantly as the failure rate of the committed unit is increased. It can be seen that the CGRR increases in similar proportion when the failure rate is doubled from Case 1 to Case 2. The CGRR increases over 4 times when the failure rate is doubled from Case 3 to Case 4. Figure 3.2 shows that the CGRR is highly sensitive to the ramp rate of a committed unit that carries an operating reserve. The CGRR is reduced more than 100 times when the ramp rates of the units are doubled from Case 1 to Case 3. Since the ramp rate of the base load generators that do not carry any spinning reserve have no impact on the risk index. The dispatch decision of non-base load units, however, can significantly influence the risk level depending on their ramp rates and the amount of regulating margin carried by these units. This study illustrates that the impact of these parameters should be evaluated prior to making unit commitment and dispatch decisions.

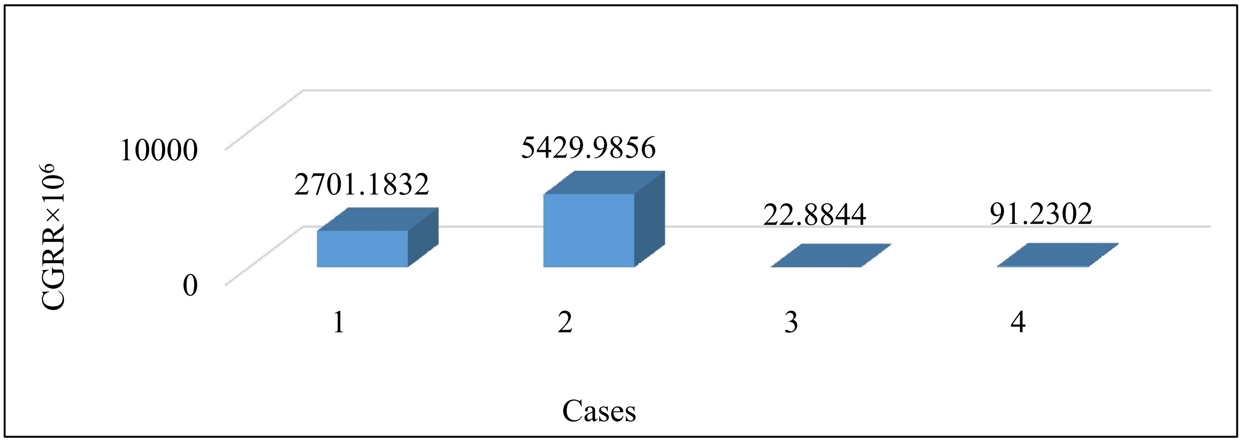


Figure 3.2: CGRR results for the case studies of the IEEE RTS operating condition in Table 3.6.

### 3.8 Benchmarking of CGRR Index

The N-1 deterministic criterion is widely used by system operators in unit commitment. Although his criterion has been perceived to be acceptable in the past, there is a growing concern with this method as modern power systems are exposed to increased uncertainties. A deterministic method cannot respond to the uncertainties introduced by rapidly growing intermittent renewable generation, changing load behaviours and electricity market rules. A probabilistic approach, such as the proposed CGRR method is a potential alternative to address these concerns. It will be important to determine an acceptable value of CGRR to help system operators make appropriate decision in unit commitment and load dispatch.

It is an important task to determine the acceptable magnitude of operating risk that should be used as a reliability criterion to make operating decisions. In an explicit sense, the operating costs associated with maintaining a specified level of operating reliability should be justified by the worth to the consumers. However, it is not an easy task to determine the reliability worth, and efforts to determine the cost of different magnitudes and duration of interruptions to the various types of consumers have been reported from time to time. Many electric utilities have relied on past performance evaluation to determine the criterion value when adopting a new reliability index. This practical approach is illustrated in this section by considering existing methods for unit commitment and load dispatch to determine an acceptable CGRR criterion for the IEEE-RTS.

The N-1 criterion is used for the unit commitment and an economic load dispatch for unit loading. Since the economic load dispatch minimizes the cost of energy production, the units with the lowest operating cost would be operated at full capacity. The committed units with the highest operating cost would operate at the minimum operating level to reduce the operating cost. The loading of the committed generating units with the objective of minimizing the operating cost, therefore, limits the regulating margin. A change in the load sharing can provide an increased regulating margin with an increased operating cost. Table 3.9 shows the CGRR evaluated for the different loading conditions between the minimum and the maximum load of the IEEE RTS, The generating units are committed to meet the different load levels using the N-1 criterion. Table 3.9 also shows the number of committed units and the regulating margin for each operating condition considering a response time of 10 minutes. The results show that the CGRR increases as the load is increased from 950 MW to 2845 MW where the overall risk value is increased by 1.76 %. As more units are brought online to serve an increased load, the number of contingencies and the probability of unit outages also increase leading to increased CGRR. The increase in CGRR as a function of the number of units committed to meet the N-1 criterion

Table 3.9: Bench marking of CGRR value.

| Load (MW) | no. of units | O.R. (MW) | CGRR $\times 10^6$ | RM (MW) |
|---|---|---|---|---|
| 950 | 7 | 400 | 2686.3312 | 90 |
| 1147 | 8 | 400 | 2686.9257 | 150 |
| 1344 | 9 | 400 | 2685.9168 | 210 |
| 1541 | 10 | 400 | 2688.1257 | 229 |
| 1696 | 11 | 400 | 2691.4024 | 229 |
| 1851 | 12 | 400 | 2695.7557 | 229 |
| 2006 | 13 | 400 | 2701.1832 | 229 |
| 2161 | 14 | 400 | 2707.6827 | 229 |
| 2261 | 15 | 400 | 2713.7336 | 210 |
| 2361 | 16 | 400 | 2719.7808 | 229 |
| 2461 | 17 | 400 | 2725.8249 | 229 |
| 2537 | 18 | 400 | 2727.9322 | 229 |
| 2613 | 19 | 400 | 2730.0398 | 229 |
| 2689 | 20 | 400 | 2732.1479 | 229 |
| 2765 | 21 | 400 | 2734.2563 | 229 |
| 2777 | 22 | 400 | 2734.2563 | 229 |
| 2789 | 23 | 400 | 2734.2563 | 229 |
| 2801 | 24 | 400 | 2734.2563 | 229 |
| 2813 | 25 | 400 | 2734.2563 | 229 |
| 2825 | 26 | 400 | 2734.2563 | 229 |
| 2845 | 27 | 400 | 2734.2705 | 229 |

is shown in Figure 3.3. It can be noted from Table 3.9 that the regulating margin remains constant at 229 MW in all the operating conditions that have more than 9 units committed to meet the load with the N-1 criterion. It is discussed earlier that the risk value depends on the regulating margin, which is in turn depends on the ramp rates of the units with spinning reserves. The increase in CGRR in Figure 3.3 is mainly contributed by the increased probability of unit outages as the number of units is increased.

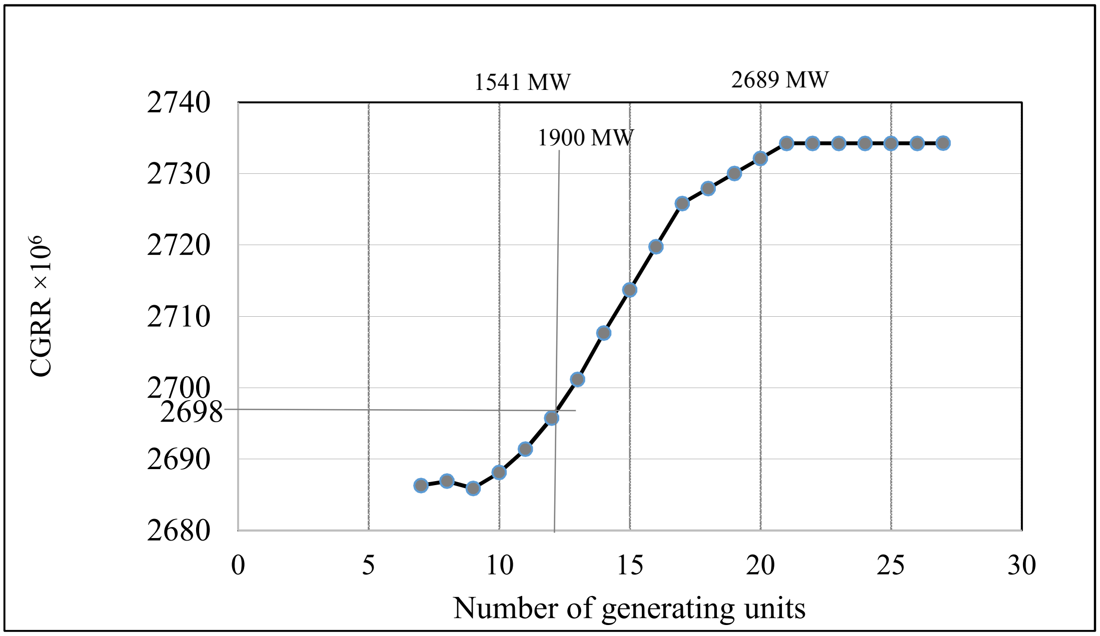


Figure 3.3: CGRR variation with different operating conditions.

An operating condition for an average load of 1900 MW assuming an annual load factor of 67% results in a CGRR value of 0.002698, which can be used as the starting CGRR criterion is adopting this new approach in the IEEE-RTS. This criterion however may not be suitable for other power systems as the operating risks are influenced by characteristics and uncertainties inherent in the respective system. It is important to analyze each system using the approach illustrated in this section to determine the appropriate CGRR criterion for the particular system.

The criterion can then be revised based on operating experience and customer satisfaction surveys.

### 3.9 Conclusions

This chapter proposes a new probabilistic risk index represented as the CGRR to quantify the power system operating risk. The analytical procedure to calculate the CGRR is illustrated by suitable examples. A simulation technique was also developed by utilizing sequential MCS to evaluate and validate the proposed risk index. As the evaluation of CGRR takes consideration of the both unit commitment risk and response risk parameters, it represents a comprehensive operating risk. It was found that the consideration only up to the fourth order contingency in the presented analytical method provides CGRR results with reasonable accuracy for the IEEE RTS. A benchmarking approach to estimate an acceptable CGRR criterion is also illustrated for the IEEE-RTS and a CGRR of 0.002698 was established as an acceptable the CGRR for the system. It is seen that if the regulating margin does not increase even after bringing a new unit online, the system risk can increase as the failure rate of the new unit contributes the CGRR index. The sensitivity studies with varying unit failure rates and ramp rates showed that the CGRR is more sensitive to the unit ramp rate than the unit failure rate. This information will be an important in decision making while allocating load and spinning reserve to the generating units.

# 4 APPLICATION OF CGRR CRITERION IN POWER SYSTEM OPERATION

## 4.1 Introduction

This chapter illustrates the application of the CGRR index in power system operating decision making. The first part of this chapter presents different unit commitment and dispatch scenarios in the IEEE-RTS, and the CGRR is evaluated for the each operating condition. The results are analyzed to recognize the difference between existing risk concepts and the proposed new CGRR concept in power system risk assessment. This section also illustrates the results from the studies to emphasize the need of CGRR evaluation for reliable power system operation. The second part of this chapter includes studies that apply the CGRR criterion in power system operation. The unit commitment and load dispatch techniques are illustrated on the test system with the application of the CGRR index.

## 4.2 The Significance of CGRR Evaluation in Power System Operation

The CGRR index is influenced by both the unit commitment and the dispatch of the generating units. The relation between the unit commitment risk and/or the response risk with the CGRR is an important question. Reference [1] points out the problem with assigning all spinning reserve to only one generating unit and illustrates that diversifying the reserve in different units increases response capacity and decreases the response risk. Various operating conditions are examined in this section to observe how the operating risk is represented by the CGRR index. Six different operating scenarios are presented in Table 4.1 for the IEEE RTS to satisfy a system load of 1995 MW. A probabilistic risk criteria of UCR<0.001 is utilized for unit commitment and the committed units are loaded using the economic load dispatch method.

Table 4.1: Different generation scenarios for 1995 MW load.

| Units | Unit Capacity (MW) | scenario 1 | scenario 2 | scenario 3 | scenario 4 | scenario 5 | scenario 6 |
|---|---|---|---|---|---|---|---|
| U1 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| U2 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| U3 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| U4 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| U5 | 400 | 400 | X | 400 | X | 400 | 400 |
| U6 | 400 | 400 | 400 | 400 | X | X | 400 |
| U7 | 350 | 302 | 350 | X | 350 | X | 269 |
| U8 | 197 | 80 | 80 | 80 | 124 | 108 | X |
| U9 | 197 | 80 | 80 | 80 | 124 | 108 | X |
| U10 | 197 | 80 | 80 | 80 | 124 | 108 | 80 |
| U11 | 155 | 151 | 155 | 155 | 155 | 155 | 132 |
| U12 | 155 | 151 | 155 | 155 | 155 | 155 | 132 |
| U13 | 155 | 151 | 155 | 155 | 155 | 155 | 132 |
| U14 | 155 | X | 155 | 155 | 155 | 155 | 132 |
| U15 | 100 | X | 93 | 68 | 100 | 100 | 40 |
| U16 | 100 | X | 93 | 68 | 100 | 100 | 40 |
| U17 | 100 | X | X | X | 100 | 100 | 40 |
| U18 | 76 | X | X | X | 76 | 76 | X |
| U19 | 76 | X | X | X | 76 | 76 | X |

The ‘X’ mark in Table 4.1 denotes the generating unit of the particular row is not included in the given operating scenario due to its unavailability caused by forced outage or maintenance. When a unit is unavailable for commitment, the next available generating unit from the priority order is scheduled to meet the load. It can be seen that the number of generating units committed in the 6 operating scenarios varies from 13 to 17. Also, the committed units are different in the six scenarios except for the 8 units, i.e. U1-U4 and U10-U13. All the six scenarios meet the UCR criterion of 0.001 for the lead time of 1 hour as shown in Figure 4.1. The UCR value associated with each of the 6 scenarios however vary as shown in the figure. The CGRR was also evaluated for the 6 operating scenarios for a lead time of one hour and a response time of 10 minutes, and the results are shown in Figure 4.1. Figure 4.1 shows the lack of correlation between the UCR and CGRR indices, and that the UCR and CGRR values vary in different ways and magnitudes in the 6 different operating scenarios. The main difference between the two operating risk indices is influenced by the fact that the UCR index used for unit commitment is not responsive to ramp rates and the response capacities of the committed units. As a result, the UCR evaluation gives similar operating risks for scenarios 2, 4 and 5, whereas, the CGRR varies considerably in these 3 scenarios. Scenarios 4 and 5 result in the highest the lowest operating risks using the CGRR index.

Table 4.2 shows the regulating margin for a response time of 10 minutes in the 6 operating scenarios described in Table 4.1. It can be seen that Scenarios 4 and 5 both have 17 committed units and 180 MW of regulating margin. The only difference is that Scenario 4 has a 350 MW unit in the place of a 400 MW unit in Scenario 5. The failure rates of these two different units are also comparable. But the corresponding CGRR for Scenario 4 is four times greater than that of Scenario 5. It should however be noted that the large difference in operating risk is not caused by

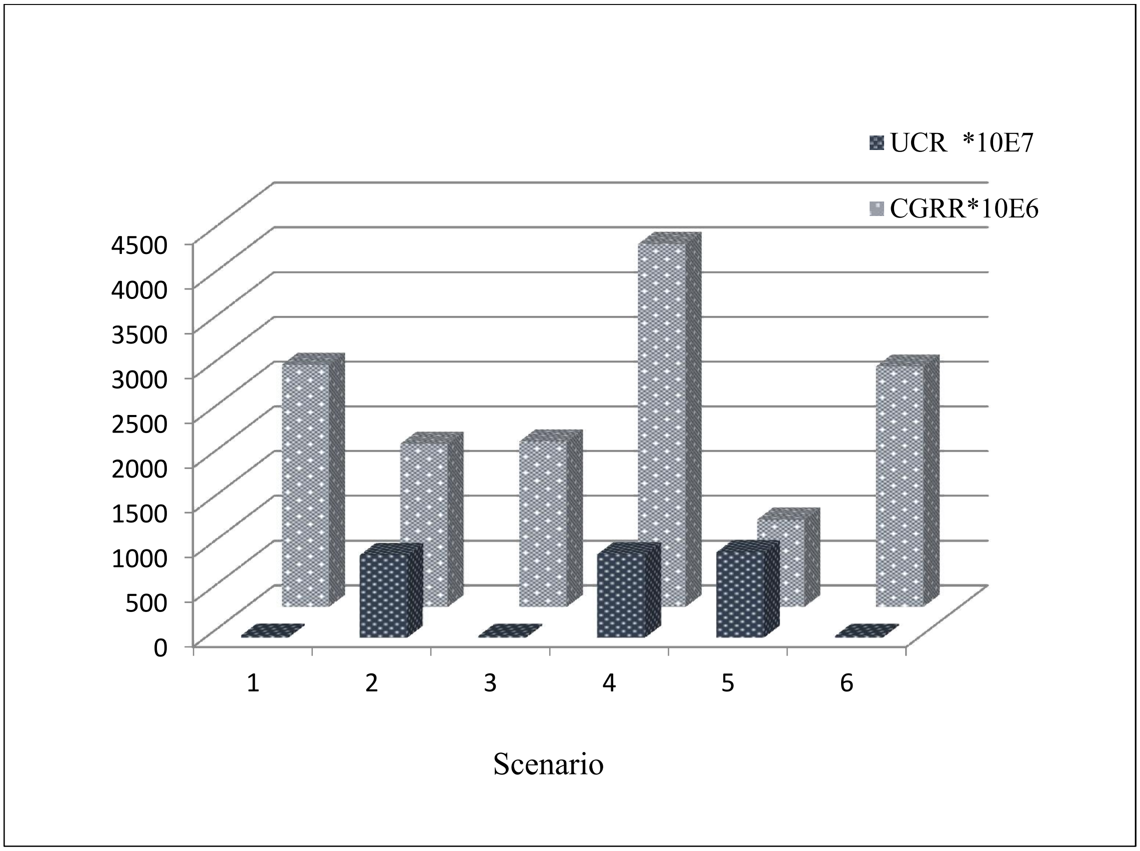


Figure 4.1: CGRR and UCR.

the unit failure rates or the unit ramp rates in this case. This difference is mainly caused by the increased number of first order contingencies in Scenario 4. In scenario 4, there are four first order contingencies which can cause load curtailment. The outage of the 400 MW unit is the only first order contingency in Scenario 5 that can cause load curtailment. As the first order contingencies will have dominant contribution to the risk level, the CGRR index is very high in Scenario 4.

Another interesting observation from Table 4.3 is for Scenarios 3 and 6. Although both operating scenarios have the same number of generating units, Scenario 3 has 85 MW or 35%

less RM than that of Scenario 6. A decrease in RM generally results in an increase in response risk. Additionally, the RM in Scenario 3 is distributed over five generating units, while it is

Table 4.2: CGRR and RM.

| Scenario | # of units | CGRR | RM (MW) |
|---|---|---|---|
| 1 | 13 | 0.002701 | 240 |
| 2 | 15 | 0.001822 | 195 |
| 3 | 15 | 0.001846 | 240 |
| 4 | 17 | 0.004053 | 180 |
| 5 | 17 | 0.000974 | 180 |
| 6 | 15 | 0.002685 | 325 |

distributed among nine units in Scenario 6. Distributing the total RM among fewer committed units generally increases the response risk. On the contrary, the CGRR of Scenario 3 is less than that of Scenario 6. A reduction in CGRR in Scenario 3 in comparison with Scenario 6 is also mainly due to the fewer number of first order credible contingencies in Scenario 3. It should also be noted that the unit U7 in Scenario 6 carries the largest portion of the total regulating margin, and therefore, the CGRR is highly sensitive to any disturbance of this unit. A careful attention should therefore be taken while allocating regulating margin among the different generating units.

## 4.3 Power System Operation Using CGRR Criterion

An off-line CGRR evaluation of the past operating conditions of the system can be first carried out for a specified period in order to comprehend the operating risks associated with past

Table 4.3: RM distribution of some cases of Table 4.1.

| Scenario 2 | | Scenario 4 | | Scenario 5 | | Scenario 3 | | Scenario 6 | |
|---|---|---|---|---|---|---|---|---|---|
| Loading (MW) | RM (MW) | Loading (MW) | RM (MW) | Loading (MW) | RM (MW) | Loading (MW) | RM (MW) | Loading (MW) | RM (MW) |
| 50 | 0 | 50 | 0 | 50 | 0 | 50 | 0 | 50 | 0 |
| 50 | 0 | 50 | 0 | 50 | 0 | 50 | 0 | 50 | 0 |
| 50 | 0 | 50 | 0 | 50 | 0 | 50 | 0 | 50 | 0 |
| 50 | 0 | 50 | 0 | 50 | 0 | 50 | 0 | 50 | 0 |
| 400 | 0 | 350 | 0 | 400 | 0 | 400 | 0 | 400 | 0 |
| 350 | 0 | 124 | 60 | 108 | 60 | 400 | 0 | 400 | 0 |
| 80 | 60 | 124 | 60 | 108 | 60 | 80 | 60 | 269 | 81 |
| 80 | 60 | 124 | 60 | 108 | 60 | 80 | 60 | 80 | 60 |
| 80 | 60 | 155 | 0 | 155 | 0 | 80 | 60 | 132 | 23 |
| 155 | 0 | 155 | 0 | 155 | 0 | 155 | 0 | 132 | 23 |
| 155 | 0 | 155 | 0 | 155 | 0 | 155 | 0 | 132 | 23 |
| 155 | 0 | 155 | 0 | 155 | 0 | 155 | 0 | 132 | 23 |
| 155 | 0 | 100 | 0 | 100 | 0 | 155 | 0 | 40 | 30 |
| 93 | 7 | 100 | 0 | 100 | 0 | 68 | 30 | 40 | 30 |
| 93 | 7 | 100 | 0 | 100 | 0 | 68 | 30 | 40 | 30 |
| | | 76 | 0 | 76 | 0 | | | | |
| | | 76 | 0 | 76 | 0 | | | | |

operator practice and the system operating performance. The off-line assessment can be used to determine the operating conditions with CGRR values significantly above and below the accepted criterion value. For these operating conditions, the load dispatch and/or the unit commitment should be rescheduled and CGRR evaluated until an acceptable value is obtained at the lowest possible cost.

Figure 3.3 shows the CGRR of the IEEE-RTS obtained from an off-line evaluation of the different operating conditions as the load is varied from its minimum value to its peak. For example, the operating schedule to satisfy a load of 1995 MW using an N-1 unit commitment and economic load dispatch results in a CGRR of 0.002701, which exceeds the specified criterion value of 0.002698. It is necessary to re-dispatch the units in such a way that the total regulating margin will increase and reduce the CGRR to an acceptable level. It should be noted that the CGRR is also sensitive to the failure rates of the units carrying the regulating margin.

The new load dispatch should be as economical as possible within the risk constraint when the committed units are re-dispatched to meet the CGRR criterion. The potential generating units for rescheduling are grouped into two classes, Class A and B. A Class A unit has a ramping capability greater than its current operating reserve, whereas, a Class B unit as an operating reserve greater than its ramping capability. A part of the load from a Class A unit should be transferred to a Class B unit in order to increase the system regulating margin within the response time. This process is carried out iteratively in small load steps. The loading from the generator with the highest incremental operating cost in Class A is first transferred to the generator with the lowest incremental operating cost of Class B. After each incremental load transfer, the CGRR is calculated, and the load transfer process is repeated until the desired CGRR value is achieved.

Table 4.4 shows the rated and loading capacities of the 13 generating units committed to meet a load of 1995 MW in the IEEE-RTS. The table shows the economic load dispatch (ELD) and the re-dispatch to meet the CGRR criterion. The Class A and B units are also indicated along with the unit ID numbers in the first column. A part of the load from Class A units 7, 11, 12 and 13 is transferred to Class B units 8, 9 and 10 so that the CGRR criterion is satisfied. The

Table 4.4 Example of economic re-dispatch in the IEEE-RTS operating schedule to meet CGRR criterion.

| Units | MCR (MW) | Ramping capability (MW) | ELD | | Re-dispatch | |
|---|---|---|---|---|---|---|
| | | | Loading (MW) | RM (MW) | Loading (MW) | RM (MW) |
| 1-A | 50 | 50 | 50 | 0 | 50 | 0 |
| 2-A | 50 | 50 | 50 | 0 | 50 | 0 |
| 3-A | 50 | 50 | 50 | 0 | 50 | 0 |
| 4-A | 50 | 50 | 50 | 0 | 50 | 0 |
| 5 | 400 | 0 | 400 | 0 | 400 | 0 |
| 6 | 400 | 0 | 400 | 0 | 400 | 0 |
| 7-A | 350 | 90 | 302 | 48 | 276 | 74 |
| 8-B | 197 | 60 | 80 | 60 | 104 | 60 |
| 9-B | 197 | 60 | 80 | 60 | 104 | 60 |
| 10-B | 197 | 60 | 80 | 60 | 104 | 60 |
| 11-A | 155 | 50 | 151 | 4 | 135 | 19 |
| 12-A | 155 | 50 | 151 | 4 | 136 | 19 |
| 13-A | 155 | 50 | 151 | 4 | 136 | 19 |
| Total | 2406 | 620 | 1995 | 240 | 1995 | 311 |

resulting CGRR is 0.0026979 which is within the criterion value of 0.002698. The regulating margins associated with the two dispatches are also shown in the table. It can be seen that an increase in 71 MW of the total regulating margin was required to maintain the acceptable CGRR criterion.

The off-line evaluation and results provide useful information to understand the required changes in unit commitment and load dispatch in order to maintain the CGRR at an acceptable level as operating conditions change over time. This creates a knowledge base to implement the CGRR approach in real time applying predictive evaluation using the proposed techniques.

The decision to make the transition to the new probabilistic approach in a continuously operating power system can begin at an operating condition at which the CGRR value is within the acceptable level. The presented method can then be applied in real-time with repeated calculation of the CGRR by incorporating short-term forecast of system changes. This process is illustrated by the algorithm in Figure 4.2.

The next operating decision in an operating condition is initiated by the short-term forecast of system changes within the lead time of the ready to start generating units available in the system. The change in loading to satisfy the system change is first determined using an economic load dispatch. The CGRR for the new economic load dispatch is evaluated and compared with the accepted criterion as shown in Figure 4.2. This new dispatch action is taken if the CGRR criterion is satisfied. If the criterion in not met, the economic dispatch is modified by transferring the load from the Class A units to the Class B units one step at a time in a recursive approach until the CGRR criterion is satisfied. A decision is then taken to implement the resulting load dispatch that meets the risk criterion. If the system does not have adequate regulating margin to meet the CGRR criterion, the commitment of the next available standby unit with the lowest incremental operating cost is considered as the additional generating unit in the CGRR evaluation, and the load dispatch that results in an acceptable CGRR value is determined by repeating the above described process as shown in the algorithm. A decision is then taken to commit the selected additional unit. The CGRR evaluation and the implementation decision proceed continuously in time chronology in order to consistently maintain the CGRR within the acceptable criterion value.

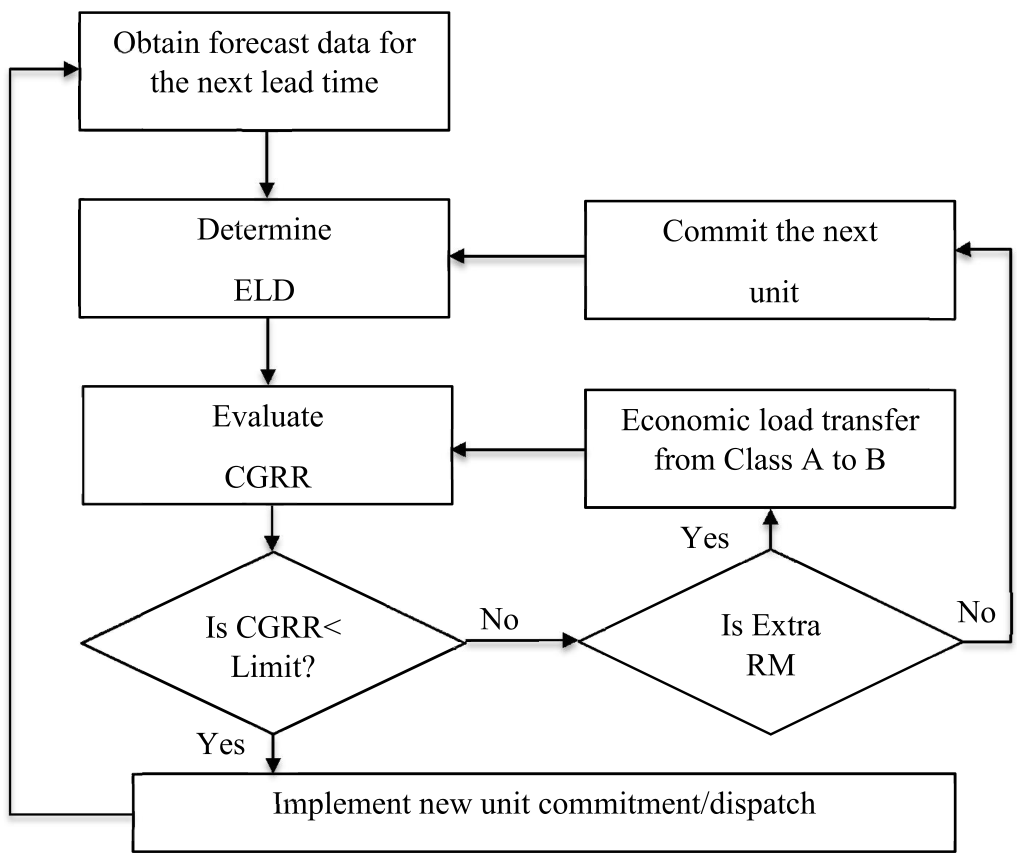


Figure 4.2: Algorithm for implementing CGRR criterion in operating decisions.

The algorithm in Figure 4.2 is further illustrated with an example of an IEEE RTS operating condition in which 13 generating units are committed from the priority loading order. The total committed generation capacity is 2406 MW. In this example, the failure rates of the individual generating units are assumed to be 1.5 times of their original values. It is assumed that the short-term system load forecast is 2006 MW in this example. The economic load dispatch (ELD) of the committed 13 units to meet the forecast load is shown in the 4th column of Table 4.5. The total regulating margin is 230 MW, and the resulting CGRR is 0.004062. These results

Table 4.5: IEEE RTS of 2006 MW load with different operating conditions.

| Unit | MCR | Ramping capability | 13 units ELD | | 13 units re-dispatch | | 14 units ELD | | 14 units re-dispatch | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | loading | RM | loading | RM | loading | RM | loading | RM |
| 1 | 50 | 50 | 50 | 0 | 50 | 0 | 50 | 0 | 50 | 0 |
| 2 | 50 | 50 | 50 | 0 | 50 | 0 | 50 | 0 | 50 | 0 |
| 3 | 50 | 50 | 50 | 0 | 50 | 0 | 50 | 0 | 50 | 0 |
| 4 | 50 | 50 | 50 | 0 | 50 | 0 | 50 | 0 | 50 | 0 |
| 5 | 400 | 0 | 400 | 0 | 400 | 0 | 400 | 0 | 400 | 0 |
| 6 | 400 | 0 | 400 | 0 | 400 | 0 | 400 | 0 | 400 | 0 |
| 7 | 350 | 90 | 306 | 44 | 261 | 89 | 260 | 90 | 260 | 90 |
| 8 | 197 | 60 | 80 | 60 | 136 | 60 | 80 | 60 | 86 | 60 |
| 9 | 197 | 60 | 80 | 60 | 136 | 60 | 80 | 60 | 86 | 60 |
| 10 | 197 | 60 | 80 | 60 | 136 | 60 | 80 | 60 | 86 | 60 |
| 11 | 155 | 50 | 153 | 2 | 112 | 43 | 126 | 29 | 121 | 34 |
| 12 | 155 | 50 | 153 | 2 | 112 | 43 | 126 | 29 | 121 | 33 |
| 13 | 155 | 50 | 153 | 2 | 112 | 43 | 126 | 29 | 122 | 33 |
| 14 | 155 | 50 | | | | | 126 | 29 | 122 | 33 |

Note: All units in MW

are shown in the first row of Table 4.6. The operating risk is unacceptable as it is well above the criterion value of 0.002698. Following the algorithm in Figure 4.2, a re-dispatch is considered since the total regulating margin can be increased by economic load transfer from the Class A units 11, 12 and 13 to Class B units 7, 8, 9 and 10. The economic re-patch to lower the operating risk is shown in the 6$^{th}$ column of Table 4.5. The CGRR result and the total regulating margin is shown in the second row of Table 4.6. The new CGRR is 0.002740, which is also unacceptable. The regulating margin is increased by 168 MW, and cannot be further increased due to loading constraints of the committed units. In order to further decrease the CGRR, the commitment of an additional generating unit is considered as shown in the algorithm of Figure 4.2. The 8$^{th}$ column in Table 4.5 shows the economic load dispatch (ELD) of the committed units considering the addition of a 155 MW unit that has a failure rate of 9.13 occurrences per year. The total regulating margin is increased to 355 MW, and the resulting CGRR is 0.002742 as shown in the third row of Table 4.6. A re-dispatch is again considered since the CGRR still exceeds the criterion value. An economic load transfer evaluation is carried out by transferring part of the load from the Class A units 11, 12, 13 and 14 to Class B units 8, 9 and 10. The economic re-patch of the 14 generating units to lower the operating risk is shown in the 10$^{th}$ column of Table 4.5. The new CGRR is 0.000058, which is within the acceptable criterion.

Table 4.6 summarizes the CGRR results obtained during the evaluation process using the recursive algorithm of Figure 4.2. The total regulating margin and the operating costs associated with the different schedules considered during the evaluation process is also shown in the table. The study results show that the dispatch of 13 generating units, that are committed using the N-1 criterion to meet the load, cannot satisfy the CGRR criterion. The CGRR criterion can only be satisfied by committing an additional generating unit with an increased cost as shown in Table

4.6. The table also shows the increase in operating cost as the dispatch is changed from ELD in order to decrease the operating risk. The first row represents the operating decision that would be taken using the existing deterministic methods, which results in an operating cost of 19,505 \$/hr. The operating risk is however very high. The 4$^{th}$ row in Table 4.6 represents the operating decision taken using the proposed probabilistic methods, which results in a low operating risk that satisfies the CGRR criterion. The operating cost is however increased by 250 \$/hr. Table 4.6 also shows the CGRR and cost results when 2 additional units are committed. It can be seen that this operating decision is not justified by the high operating cost. The results from this study show that an increase in operating reliability or a decrease in CGRR can be achieved with an increase in operating costs. A useful contribution of the proposed approach is that it can quantify the operating reliability benefit that can be compared with the operating cost, and therefore, provide useful indicators to value based operating decisions.

Table 4.6: Example results for operating reliability and cost comparison.

| Committed units and dispatch | Total RM (MW) | CGRR $\times 10^6$ | Cost (\$/hr.) |
|---|---|---|---|
| 13 units, ELD | 230 | 4062.161706 | 19505.11 |
| 13 units, re-dispatch | 396 | 2740.451292 | 21118.19 |
| 14 units, ELD | 355 | 2742.428945 | 19582.40 |
| 14 units re-dispatch | 401 | 57.65131996 | 19755.09 |
| 15 units ELD | 442 | 60.95279158 | 20150.68 |

## 4.4 Conclusions

This chapter presents the importance and the application procedure of the CGRR index in power system operating decisions. In the beginning of this chapter, it is illustrated that unit commitment based on the probabilistic UCR index can lead to operating conditions that will result in high CGRR, since the UCR index is not responsive to generating unit ramp rates and response capabilities. Six example scenarios are presented to illustrate that operator may face a situation where generating units could have higher regulating margin as well as situations where the regulating margin is distributed among more generating units, but at the same time with an increased operating risk. This condition is appropriately identified in the IEEE RTS by the CGRR index as it includes both the UCR and the unit response capability. Further, the application of CGRR criteria in the system operation is shown by developing an algorithm which recursively evaluates the CGRR index by transferring the loads in between the generating units to modify the dispatch so that a predetermined acceptable risk is obtained as economically as possible. A 13 unit IEEE RTS operating scenario is presented to illustrate this process. An additional unit commitment was necessary to obtain the acceptable CGRR due to the insufficient response capacity of the available 13 units, ultimately increasing the overall operating cost. Thus the developed algorithm can be utilized to access all the potential operating scenarios and compare the operating cost for decision making situations.

# 5 OPERATING RISK EVALUATION OF A WIND INTEGRATED GENERATING SYSTEM

## 5.1 Introduction

Power system operating reliability can be highly influenced by the intermittency of power generation in addition to the unit outages and load variations. It is expected that the increase wind power integration to the existing grid will continue due to environmental concerns. Wind power generation is unpredictable depending upon the geological sites and wind regimes. Although operators can decide how much power to generate from conventional generating units during an operating scenario, they have limited control over the output power from the wind turbine pitch adjustment. Therefore, the uncertainty of wind generator output needs to be carefully incorporated in the operating decision methodology so that the operators can maintain an optimum amount of spinning reserve and thus an acceptable level of operational reliability. There is a need for an appropriate wind power forecasting model in operating risk evaluation of a wind integrated power system.

The first part of this chapter presents a wind power disturbance model to quantify the uncertainty of wind power in operating risk evaluation. This model identifies the possible disturbances associated with the short term wind power commitment to utilize in the power system operating domain. The developed wind power model is then incorporated in the operating risk assessment of a wind integrated generating system to obtain the CGRR index.

## 5.2 Development of a wind power model for CGRR evaluation

The essential task for the reliability assessment of wind connected power system is to develop a capacity model of a wind resource which would readily be applicable to the already developed probabilistic model for conventional systems. Adequate wind speed data from the concerned location and for the relevant period of time is needed to create a suitable wind capacity model. During a power system operating scenario, the initial wind conditions are known, and a suitable model to incorporate the uncertainty of wind power in the short future time is required to help make decisions on unit commitment and reserve requirements from other conventional units, and allocation of spinning reserves and regulating margins to committed units. The short future time is the lead time of about 1 to 4 hours. A straight forward deterministic technique for short term wind speed forecasting is the persistence model [40], which assumes that if wind is blowing right now, it is most likely to continue the same for a short time in the future. Numerical Weather Prediction (NWP) is another method of estimating future wind speed where current physical conditions such as atmospheric states are modeled by nonlinear motion equations to predict the future values [41]. The physical models are not suitable for short term wind speed prediction due to the complicated computation involved [41]. Statistical approaches such as ARMA or ARIMA models have also been used for short term forecasting [42]. Reference [17] proposes a conditional probability approach for short term wind speed forecasting by simulating large number of synthetic wind speed data using ARMA model provided in [43,44]. In this approach, a probability distribution of wind speed for the concerned lead time is developed and the analysis is carried out in a probability domain. Reference [31] utilizes wind speed data with 10 minute resolution to develop seven states wind speed distribution to capture the short time wind variability. It considers the conditional discrete distribution spaced one standard deviation apart which is derived from the historical wind speed data.

The system operating risk in a wind integrated power system can be highly influenced by the stochastic variation of wind power, if the proportion of wind power is significant relative to the total operating capacity. The knowledge regarding the maximum wind power variation during the lead time and the associated probability is an important information in risk assessment. The conditional probability approach [17] is utilized in this work to obtain the probability distribution of wind speed variation for the lead time considered conditional upon the known initial wind speed conditions

Wind speed data was converted to wind power using the power curve characteristics of the wind turbine generator (WTG). A WTG cannot produce any power for wind speeds less than the cut in speed ($V_{ci}$) and greater than the cut out speed ($V_{co}$). There is a nonlinear speed power relationship for wind speeds between $V_{ci}$ and the turbine rated speed ($V_r$). Equation 5.1 [45] is applied to covert wind speed data to wind power.

WTG output in any time,

$$P(V) = \left.\begin{cases} 0 & \text{for } V_{ci} > WSp \geq V_{co} \\ (A+B\times V(t) + C\times V(t)^2)P_r & \text{for } Vci \leq WSp < V_r \\ P_r & \text{for } V_r \leq WSp < V_{co} \end{cases}\right\} \tag{5.1}$$

where, values of A, B and C can be obtained by Equation (5.2)

$$
\left.
\begin{aligned}
A &= \frac{1}{(V_{Ci}-V_r)^2}\left(V_{Ci}(V_{Ci}+V_r) - 4V_{Ci}V_r\left(\frac{V_{Ci}+V_r}{2V_r}\right)^3\right) \\
B &= \frac{1}{(V_{Ci}-V_r)^2}\left(4(V_{Ci}+V_r)\left(\frac{V_{Ci}+V_r}{2V_r}\right)^3 - (3V_{Ci}+V_r)\right) \\
A &= \frac{1}{(V_{Ci}-V_r)^2}\left(2 - 4\left(\frac{V_{Ci}+V_r}{2V_r}\right)^3\right)
\end{aligned}
\right\} \tag{5.2}
$$

For $V_{ci}$ *=15 km/hr,* $V_r$*=50 km/hr* and $V_{co}$*=90 km/hr*, the wind power characteristic curve is shown in Figure 5.1.

The wind power values obtained from the wind speed data after passing through the power curve are utilized to develop conditional wind power during the lead time. The effect of failure rate of WTG can be considered in the modeling of the power output. As wind turbines have small individual ratings in comparison to the conventional generating units, their ORR values cause negligible impact as compared to that of wind power intermittency in the system operation [38], and therefore, the disturbance due to WTG failures is not included in this study.

Wind power can increase or decrease relative to the initial state within the lead time of an operating condition, and can adversely influence the system operation depending on the magnitude and rate of wind variation. If wind abruptly slows down, the fast ramping online generating units have to ramp up and supply the deficit power within the response time to balance the system load and generation. Also, if there is no limitation posed by the WTG, the increase in wind power will require the conventional generators to ramp down very quickly to absorb the increased wind power. The possibility of absorption of all increased wind power depends upon how much down reserve is available in the power system, otherwise the extra wind power should be wasted by wind curtailment. This study assumes that the option to spill wind

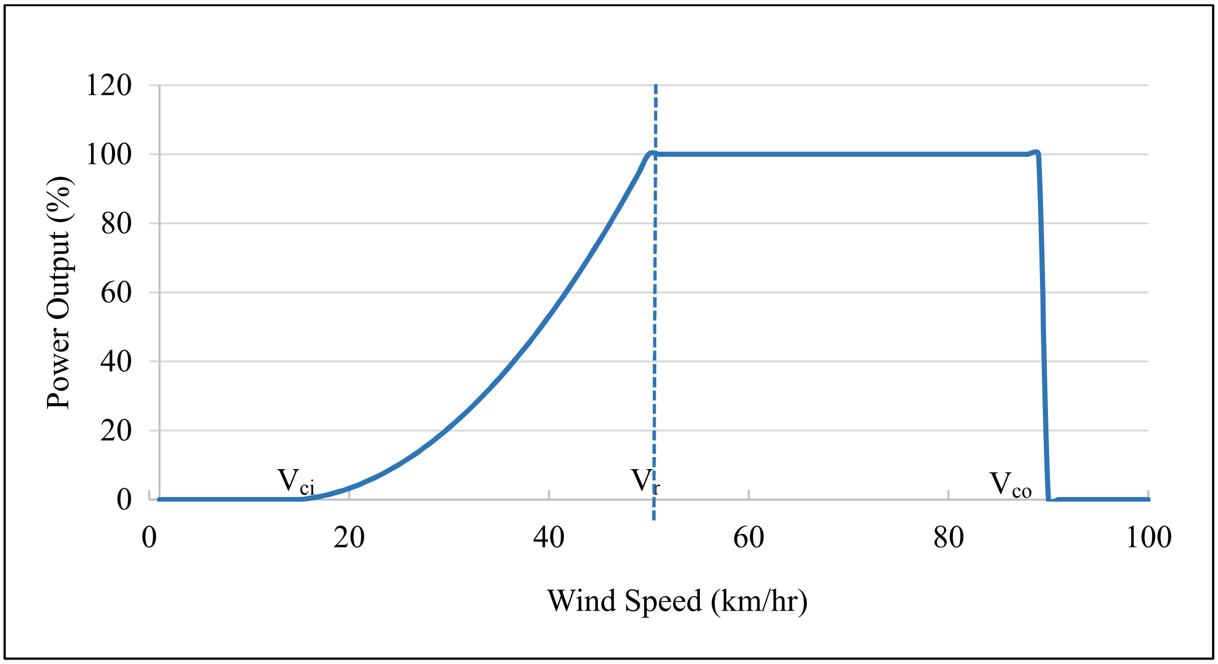


Figure 5.1: WTG characteristics curve.

energy is available if needed for power balance when wind power increases suddenly within the lead time, and thus, the disturbance due to wind increase has no impact on the operating risk. The wind power disturbance model developed in this study, therefore, does not consider the disturbances due to increment of wind power relative to the initial condition. The wind power disturbance within the lead time can vary from 0%, when the wind power is equal to the initial condition, to 100%, when the wind power is reduced to zero.

Wind speed data in 10 minute time intervals were obtained from National Renewable Energy Laboratory (NREL) for a period of 3 years, between the Year 2004 and 2006, for site ID 30450 of North Dakota [46]. A total of 57824 wind speed data were obtained for the chosen wind site. The wind speed data is converted to wind power data using Equation 5.1. Sturges' rule [47] given by the equation 5.3 is then used to find the number of wind disturbance groups in the lead time.

$$Groups = 1 + 3.3 \log n \tag{5.3}$$

where, $n$ is the total number of wind power data. For the total available data, Equation 5.3 results in 18 data groups. This means for a given initial condition, the next wind power within the lead time would be in one of the 18 possible states approximated by the mid-value of the each interval. Wind power distribution for a lead time of one hour for different initial wind power conditions are shown in Figure 5.2. It can be seen that the maximum likelihood wind power in the next hour is almost equal to the initial wind power for all considered initial wind power (IWP) conditions. This justifies the relevance of the persistence model in deterministic methods.

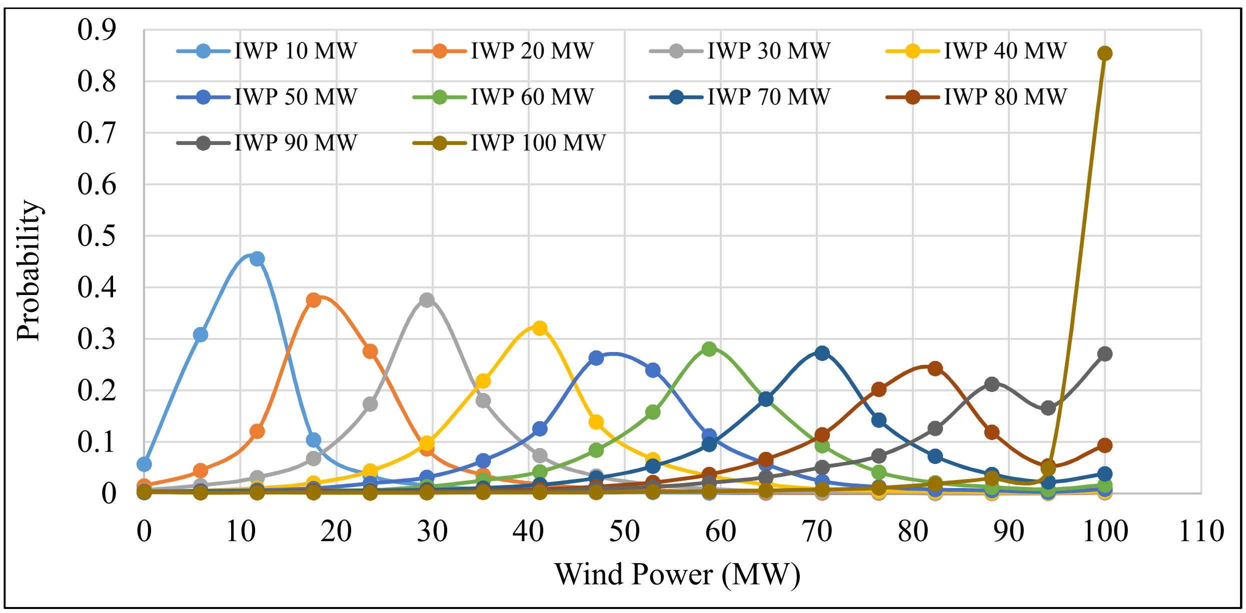


Figure 5.2: Conditional wind power distribution for different initial wind power (IWP).

An example is illustrated considering an initial wind power of 80 MW. The conditional wind power disturbance model for a lead time of one hour is shown in in Figure 5.3. It shows that there is about 24% probability that wind power will remain at 80 MW even after one hour. The probability that wind power exceeds the initial condition of 80 MW is 27%. The probability of no wind disturbance is therefore 51%. There is around 0.4% chance that wind generator may stop producing power in an hour which is denoted by 100% disturbance.

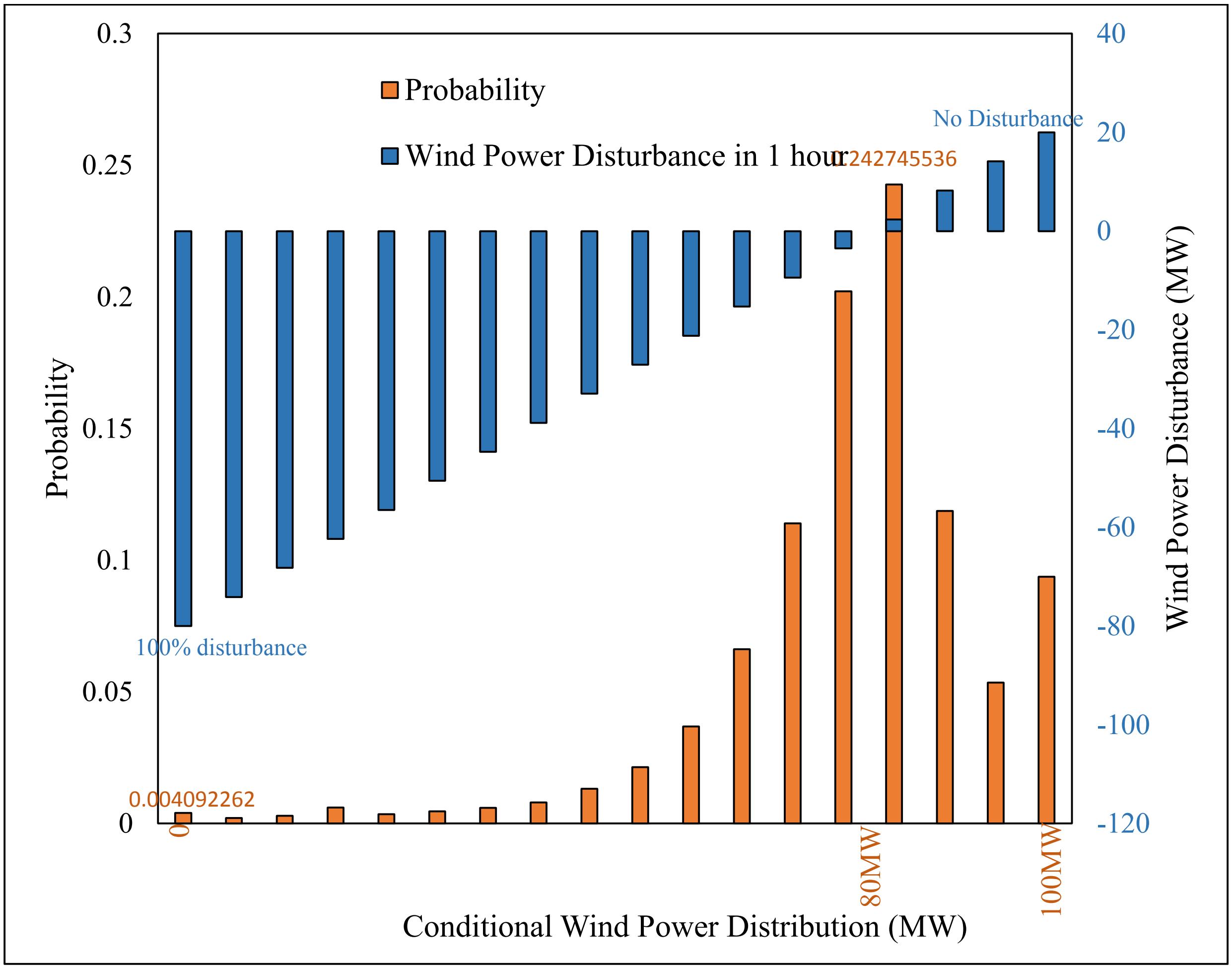


Figure 5.3: One hour wind power disturbance for 80 MW IWP.

The inclusion of all possible wind capacity states is not feasible computationally. It is possible to reduce these capacity states to an appropriate number of steps. The eighteen states wind power capacity model can therefore be reduced to a desired number of states by using a rounding technique [1] given by Equation 5.4.

$$\left.\begin{aligned} P(C_j) &= \frac{C_k - C_i}{C_k - C_j} P(C_i) \\ &\text{and} \\ P(C_k) &= \frac{C_i - C_j}{C_k - C_j} P(C_i) \end{aligned}\right\} \tag{5.4}$$

Where state $i$ falls between the required rounding states $j$ and $k$. The computation burden decreases as the number of states is reduced, but at the cost of accuracy. It is therefore desired to determine the optimum number of states in the wind power capacity model for CGRR evaluation that provides reasonable accuracy. This will be discussed in Section 5.4.

### 5.3 Operating Risk Evaluation with Wind Power Commitment

The evaluation of operating risk with wind power commitment can be carried out by considering wind as a negative load. It has been explained that wind power disturbance model in this study only considers the disturbances due to decrement of wind power relative to the initial condition. A decrement in wind power is modeled by an increment in the system load. For every operating instance, the system load is updated accordingly as all the available power output of WTG must be utilized [23]. The initial wind power is first subtracted from the system load to schedule the units. The outage of the conventional units and the sudden drop in wind power are the two types of generation disturbances considered in the system operation. The expectation of CGRR is obtained using Equation 5.5 in which the CGRR value obtained for each wind power disturbance is weighted by the corresponding wind power disturbance probability.

$$CGRR = \sum_{i=1}^{WD} (CGRR_i \times WPD_i) \tag{5.5}$$

where, $CGRR_i$ is the risk associated with the *i*th wind power disturbance state $WPD_i$ is the probability of *i*th wind power disturbance state and *WD* is the total wind disturbance states.

## 5.4 Determination of an appropriate number of wind power disturbance states

Section 5.2 showed that a total of eighteen capacity states was used based on the Sturge's rule to represent the wind disturbance probability distribution of the 10 minute resolution wind speed data collected over 3 years. The wind power model for operating reliability evaluation would include all these possible wind power states. But considering all of these states would not be beneficial due to the time consuming computations. Equation 5.4 is used to reduce the number of discrete states used to represent the probability distribution of the wind power disturbance model, and therefore reduce the computation burden. The wind disturbance model is represented by the percent decrement of the wind power relative to the initial condition and its corresponding probability. Figure 5.4 shows the wind power disturbance model for a lead time of one hour of a 800 MW wind farm assuming an initial wind power of 80 MW. The North Dakota wind characteristics described in section 5.2 is considered for the wind farm. Table 5.1a and 5.1b show the wind power disturbance (WPD) models as the number of states in the model is reduced from 15 to 2 using the apportioning technique.

A study was carried out using the IEEE RTS system to determine the minimum number of wind power disturbance states that is required to reasonably capture the wind variability, and provide CGRR results with acceptable accuracy. An operating condition to meet a load of 2613 MW is considered in the study. It is assumed that a total of 19 generating units are committed

Table 5.1a: Multistate Wind Power Disturbance (WPD) Models for IWP 80 MW.

| 15 State Model | | 11 State Model | | 6 State Model | |
|---|---|---|---|---|---|
| WPD (%) | Probability | WPD (%) | Probability | WPD (%) | Probability |
| 0 | 0.5860500 | 0 | 0.6217300 | 0 | 0.716210 |
| 7 | 0.1651300 | 10 | 0.1889500 | 20 | 0.206500 |
| 14 | 0.0952050 | 20 | 0.0934980 | 40 | 0.044944 |
| 21 | 0.0556290 | 30 | 0.0370440 | 60 | 0.015108 |
| 29 | 0.0316600 | 40 | 0.0210080 | 80 | 0.011070 |
| 36 | 0.0188360 | 50 | 0.0108270 | 100 | 0.006174 |
| 43 | 0.0117460 | 60 | 0.0066472 | | |
| 50 | 0.0074022 | 70 | 0.0060946 | | |
| 57 | 0.0055858 | 80 | 0.0064831 | | |
| 64 | 0.0043822 | 90 | 0.0030801 | | |
| 71 | 0.0036601 | 100 | 0.0046339 | | |
| 79 | 0.0057718 | | | | |
| 86 | 0.0028613 | | | | |
| 93 | 0.0019860 | | | | |
| 100 | 0.0040923 | | | | |

Table 5.1b: Multistate Wind Power Disturbance (WPD) Models for IWP 80 MW.

| 5 State Model | | 4 State Model | | 3 State Model | | 2 State Model | |
|---|---|---|---|---|---|---|---|
| WPD (%) | Probabilit y | WPD (%) | Probabilit y | WPD (%) | Probabilit y | WPD (%) | Probabilit y |
| 0 | 0.7512000 | 0 | 0.796520 | 0 | 0.848010 | 0 | 0.9 |
| 25 | 0.1936200 | 34 | 0.169780 | 50 | 0.137230 | 100 | 0.1 |
| 50 | 0.0331540 | 66 | 0.023682 | 100 | 0.014755 | | |
| 75 | 0.0145420 | 100 | 0.010018 | | | | |
| 100 | 0.0074842 | | | | | | |

from the priority loading order to meet the load with the N-1 unit commitment criterion. The total operating capacity is 3013 MW, and the largest operating unit is 400 MW in this operating condition. The CGRR for a lead time of 1 hour and a response time of 10 minutes without considering wind power is 0.002730.

It is assumed that an 800 MW wind farm is connected to the IEEE-RTS, and the wind power output at the start of the operating condition is 80 MW. The maximum possible wind power output is greater than the power outputs of several conventional units in this operating condition. The initial wind power is 3% of the system load. The North Dakota wind characteristics described in section 5.2 is considered for the wind farm. The probability distribution of the wind power disturbance for a lead time of one hour conditional upon the initial wind power condition is shown in Figure. 5.4. The CGRR index is evaluated considering the different number of states in the wind power disturbance model shown in Table 5.1a and Table 5.1b. Figure 5.5 shows the CGRR of the operating condition for a lead time of 1 hour and a response time of 10 minutes as the number of discrete states to represent the WPD model is varied from 2 to 15 states. Figure 5.5 shows that representing the WPD model by 4 or more number of states results in the same CGRR in 6 decimal places. It is found that there is not much variation on the CGRR index regardless of the number of wind disturbance states are considered at this wind penetration level. Therefore, even the reduced number of wind disturbance states would be enough to represent the risk associated wind power variation for the low level of wind penetration. Figure 5.6 shows similar CGRR results when the initial wind power is 480 MW. In this case, the wind power output is greater than the capacity rating of the largest committed unit, and it is 18% of the system load. For this level of operating wind penetration, there is significant increase in CGRR value when the WPD model is represented by less than 5 states. The results suggest that the WPD model should be represented by at least 5 states for CGRR evaluation for 18% of operating wind penetration. Figure 5.7 similarly shows the CGRR when the initial wind power is 24% of the system load. The CGRR for the 2 state WPD model is 0.083374 and not shown in the figure since this value is much higher than the CGRR obtained from the other multistate models. It can be seen from the results that the risk indices are very much different in the individual representations. In this case even the 11-state representation results in considerable error. The results from this study conclude that a higher state representation of the WPD model is required as the operating wind penetration is increased.

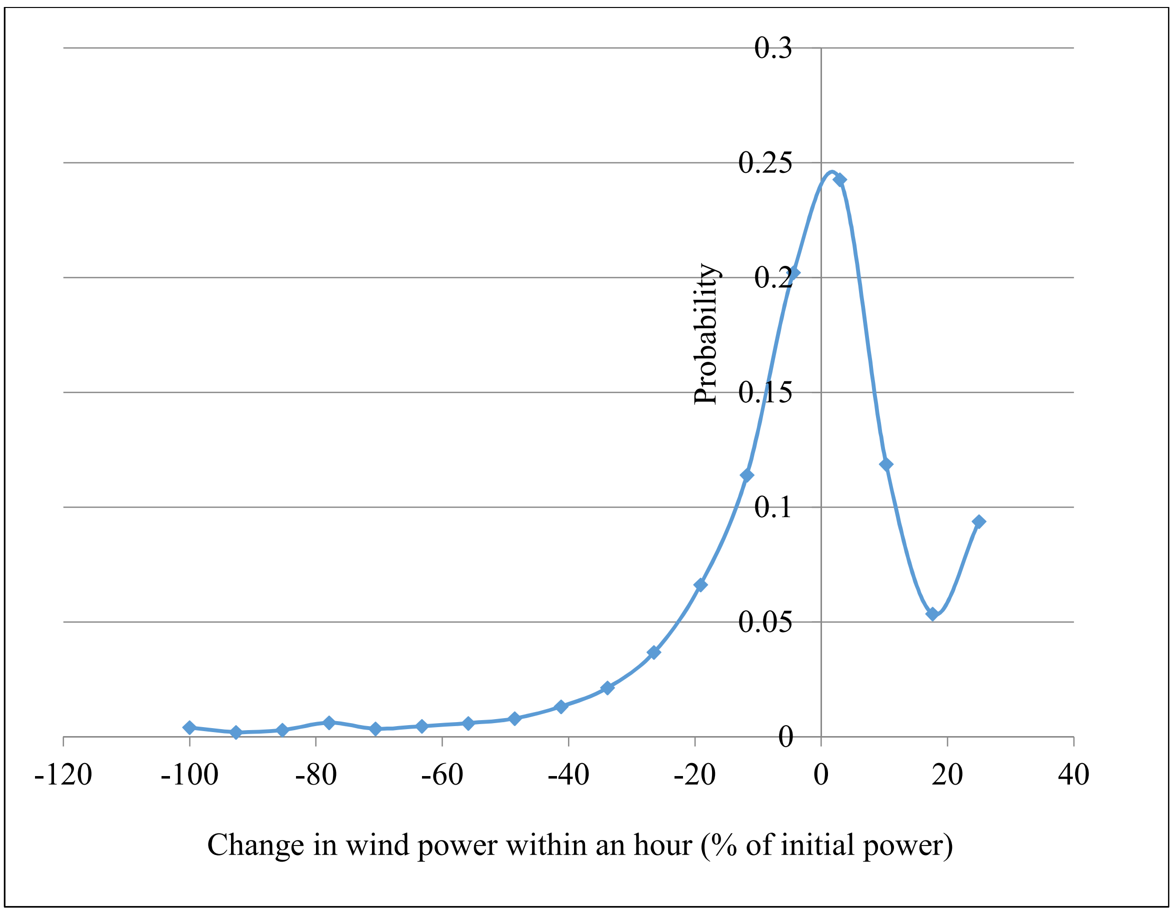


Figure 5.4: 18 State WPD model for 80 MW of IWP.


Figure 5.5: CGRR evaluated using 2 to15 state WPD models with 3% operating wind penetration.

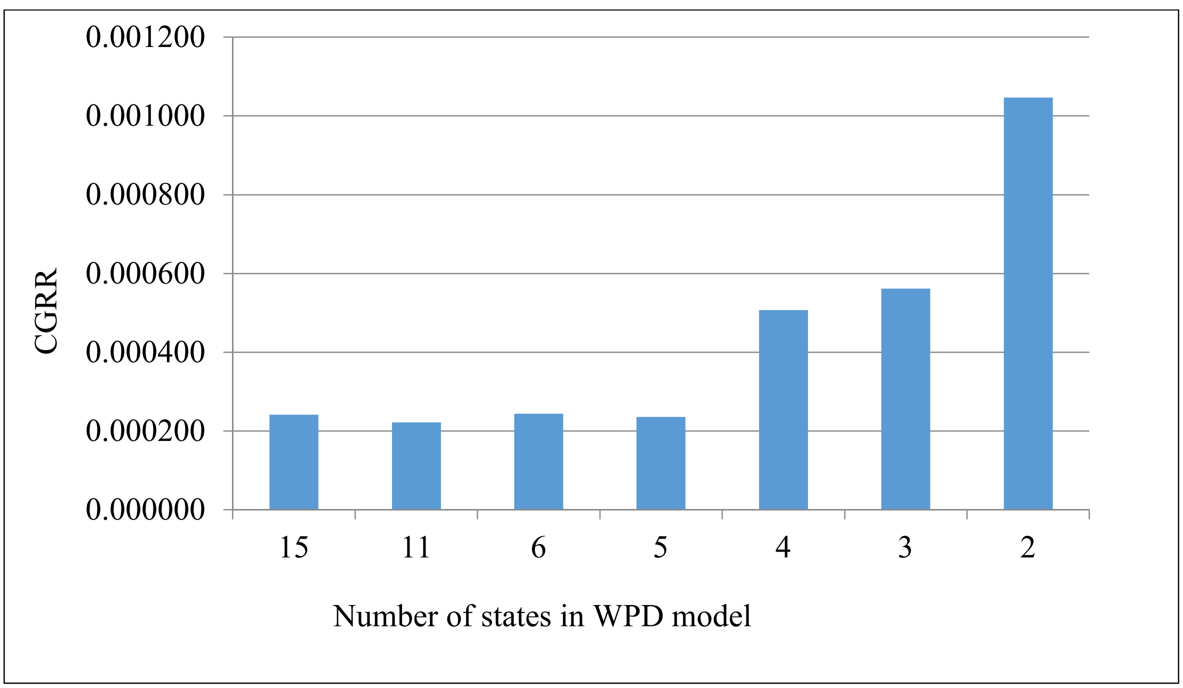


Figure 5.6: CGRR values for 2-15 state WPD model with 18% of wind penetration.

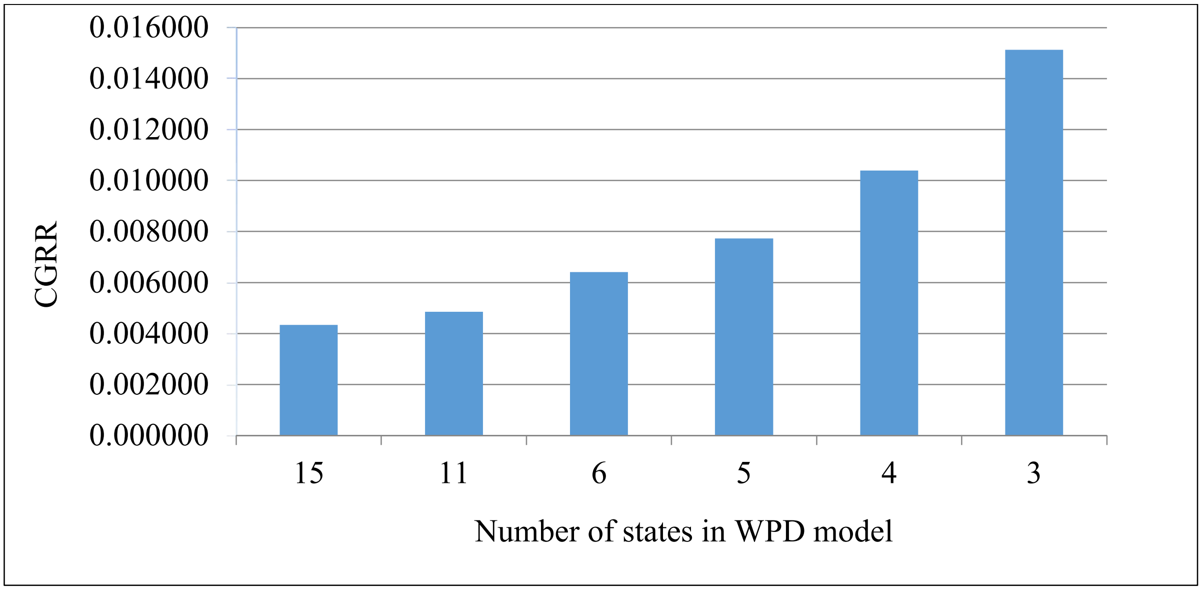


Figure 5.7: CGRR values for 3-15 state WPD model with 24% of wind penetration.

### 5.5 CGRR Evaluation of Wind Integrated Power System Operation

The operating reserve requirement during a unit commitment is generally assessed from dispatchable conventional generating units, and not from wind power resources. A study was carried out using this approach in which the required conventional units were committed to meet the N-1 criterion without consideration of the availability of wind power during the operating condition. An example of the IEEE-RTS with a total scheduled capacity of 3013 MW from 19 conventional units committed to meet the system load of 2613 MW is considered. The IEEE-RTS is assumed to be connected to an 800 MW wind farm with the North Dakota wind characteristics described in Section 5.2. The initial wind power is assumed to be 80 MW. The committed units are loaded as shown in Table 5.2 to satisfy the economic load dispatch. With an initial wind power of 80 MW, the spinning reserve is 480 MW. The outage of Unit U5 or U6 is the largest contingency resulting in the drop in 400 MW. The last column shows the regulating margin from each unit for a response time of 10 minutes. Using the WPD

Table 5.2: ELD of 19 generating units for 2613 MW of load and 80 MW of IWP.

| Unit # | MCR (MW) | Loading (MW) | RM (MW) |
|---|---|---|---|
| U1 | 50 | 50 | 0 |
| U2 | 50 | 50 | 0 |
| U3 | 50 | 50 | 0 |
| U4 | 50 | 50 | 0 |
| U5 | 400 | 400 | 0 |
| U6 | 400 | 400 | 0 |
| U7 | 350 | 350 | 0 |
| U8 | 197 | 80 | 60 |
| U9 | 197 | 80 | 60 |
| U10 | 197 | 80 | 60 |
| U11 | 155 | 155 | 0 |
| U12 | 155 | 155 | 0 |
| U13 | 155 | 155 | 0 |
| U14 | 155 | 155 | 0 |
| U15 | 100 | 57 | 30 |
| U16 | 100 | 57 | 30 |
| U17 | 100 | 57 | 30 |
| U18 | 76 | 76 | 0 |
| U19 | 76 | 76 | 0 |
| Wind | - | 80 | 0 |
| Total | 3013 | 2613 | 270 |

Table 5.3: Wind penetration levels.

| IWP (MW) | 0 | 80 | 160 | 240 | 320 | 400 | 480 | 560 | 640 | 720 |
|---|---|---|---|---|---|---|---|---|---|---|
| IWP (% of load) | 0 | 3 | 6 | 9 | 12 | 15 | 18 | 21 | 24 | 28 |

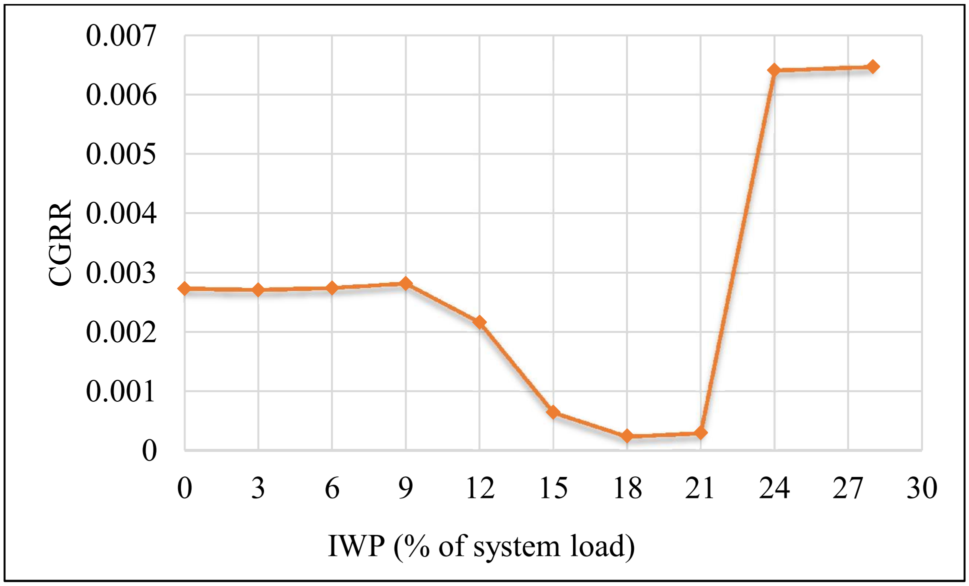


Figure 5.8: CGRR for unit commitment without considering wind.

model shown in Table 5.1a, the CGRR was found to be 0.0027091. The CGRR was also calculated for different initial wind power conditions shown in Table 5.3. The obtained CGRR values are plotted in Figure 5.8 for different amount of initial wind power. Figure 5.8 that at first the CGRR decreases with the increase in IWP. The reason is that the conventional units have adequate regulating margin to absorb the wind power, and the additional spinning reserve due to increased wind power results in a lower operating risk. The figure also shows that the reduction in CGRR stops as IWP reaches around 21% and instead starts increasing with the increased wind power penetration level. This increment in CGRR is due to the increased probability of large wind power drops which cannot be fulfilled by ramping up of scheduled units within the response time. Figure 5.8 suggests that wind power penetration of 18% provides the lowest operating risk for the considered operating condition.

In the example of unit commitment shown in Table 5.2, the number of units committed is 19. The operating reserve without considering wind power is 400 MW, and is equal to the capacity of the largest committed unit. The operating reserve considering the initial wind power of 80 MW is however 480 MW which is greater than that is required in the N-1 criterion.

The following study presents a different approach in which the wind power available during an operating scenario is considered in unit commitment when assessing the operating reserve. Using this approach, the unit commitment based on the N-1 criterion requires only 18 units as shown in Table 5.4 for 80 MW IWP. The loading of the committed units according to the ELD, and the distribution of RM within a response time of 10 minutes are also shown in the same table. A comparison of the total RM in Table 5.2 and 5.4 shows that the regulating margin is reduced by 37 MW when the wind power is considered in the unit commitment. The CGRR index calculated in this case is 0.0027529.

Unit commitment using the N-1 criterion will require fewer numbers of conventional units as the initial wind power is increased as shown in Figure 5.9. It can be seen that only 15 units are required to meet the N-1 criterion when the initial wind power is 15% of the load. The CGRR was evaluated considering different levels of initial wind power, and the results are shown in Figure 5.10.

Table 5.4: ELD of 18 generating units for 2613 MW of load and 80 MW of IWP.

| Unit # | MCR (MW) | Unit loading (MW) | RM (MW) |
|---|---|---|---|
| U1 | 50 | 50 | 0 |
| U2 | 50 | 50 | 0 |
| U3 | 50 | 50 | 0 |
| U4 | 50 | 50 | 0 |
| U5 | 400 | 400 | 0 |
| U6 | 400 | 400 | 0 |
| U7 | 350 | 350 | 0 |
| U8 | 197 | 80 | 60 |
| U9 | 197 | 80 | 60 |
| U10 | 197 | 80 | 60 |
| U11 | 155 | 155 | 0 |
| U12 | 155 | 155 | 0 |
| U13 | 155 | 155 | 0 |
| U14 | 155 | 155 | 0 |
| U15 | 100 | 82.33 | 17.66 |
| U16 | 100 | 82.33 | 17.66 |
| U17 | 100 | 82.33 | 17.66 |
| U18 | 76 | 76 | 0 |
| Wind | 80 | 80 | 0 |
| Total | 3093 | 2163 | 233 |

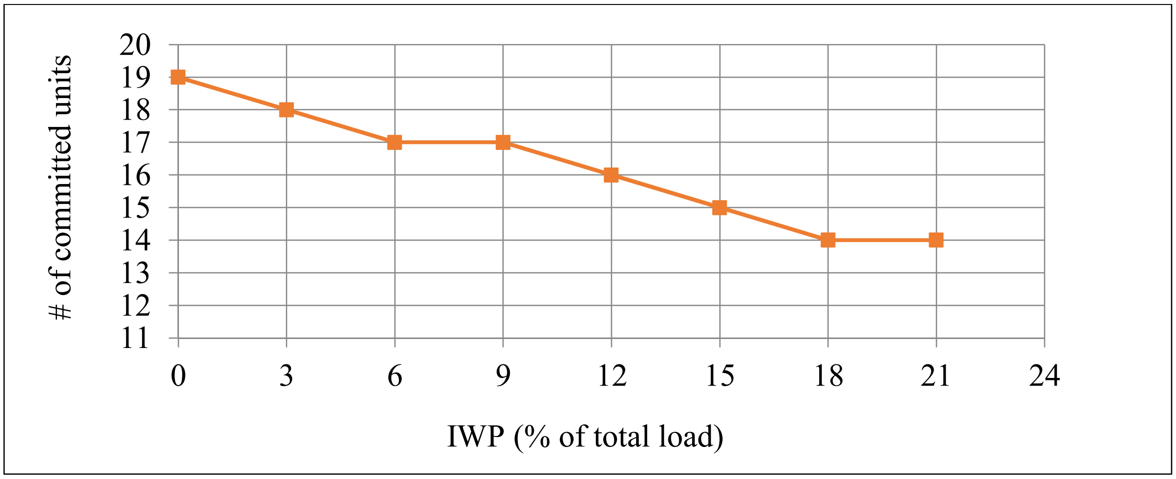


Figure 5.9: Number of units to be committed using the N-1 criterion when initial wind power is considered.

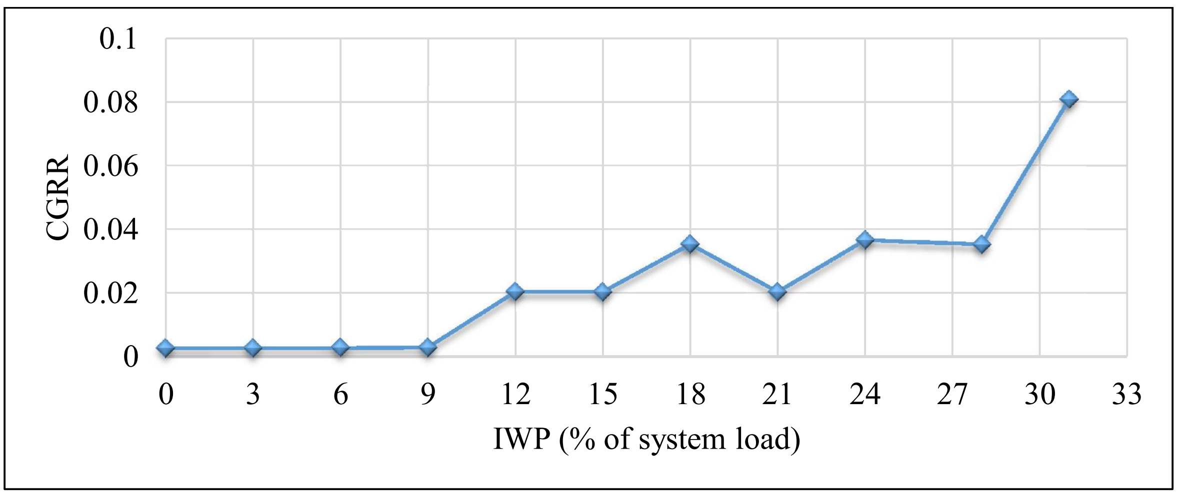


Figure 5.10: CGRR with considering wind power in unit commitment.

Figure 5.10 shows that, in general CGRR increases with the increase in IWP. This is due to higher probabilities of larger disturbances and low amount of available regulating margins. It should be noted however that the CGRR drops when the initial wind power penetration increases from 18% to 21%. The reason is that the number of committed conventional units is the same in both these cases, and the increased regulating margin due to increased wind power absorption at 21% penetration results a lower CGRR value.

The decision to include or not to include wind power during unit commitment will considerably affect the operating risk as illustrated in the examples. Consideration of wind power in unit commitment using the N-1 deterministic criterion will result in fewer conventional units to be committed, and therefore, their capacities are utilized to their limits. This increases CGRR as there is insufficient available regulating margin to respond to the possible wind variability and conventional generating unit failure. It can be seen in Figure 5.11 that for up to 9% of operating wind penetration, the risk indices are similar regardless of wind power being included or not during unit commitment. The figure shows that unit commitment considering wind power results in considerably higher operating risk in comparison to the unit commitment without considering wind power when wind power penetration exceeds 12% of the load. As wind power integration continues to grow throughout the world, it will be increasingly important to consider wind power in operating decisions, such as unit commitment. The results from above study clearly show that the deterministic N-1 criterion will result in very high operating risk when wind power is considered in unit commitment. It is therefore recommended that probabilistic risk criteria, such as the CGRR, be used in operating decisions in order to maintain a consistent operating risk.

## 5.6 Wind Integrated System Operating Decisions Using the CGRR Index

The usefulness of the CGRR index for operating decisions of wind integrated power system is presented in this section. As the operating wind penetration increases during system operation, the probability of large disturbances due to wind power decrement within the lead time will increase, and therefore, the system will be exposed to a higher operating risk. The operation, the probability of large disturbances due to wind power decrement within the lead

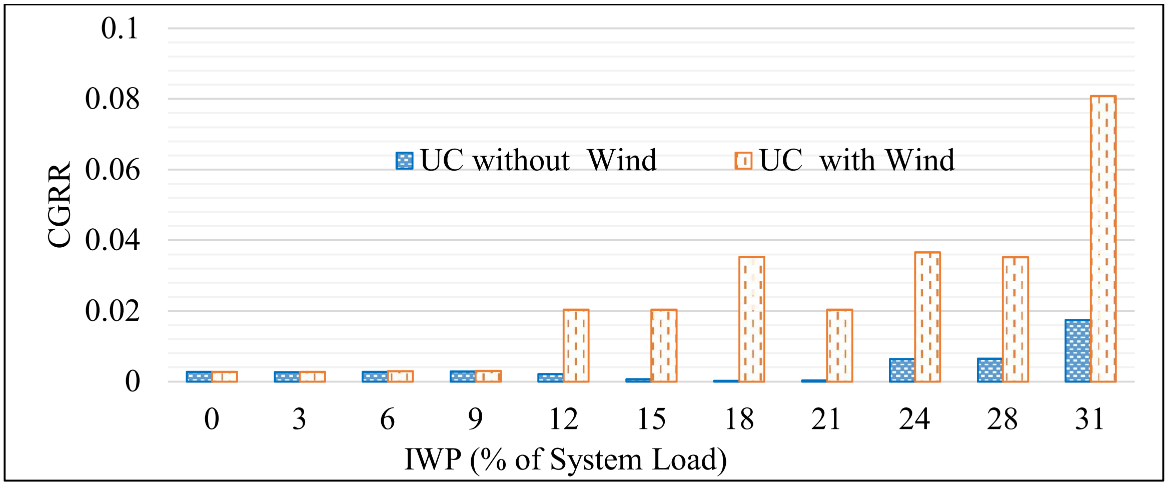


Figure 5.11: Comparison of CGRR values.

time will increase, and therefore, the system will be exposed to a higher operating risk. The operators have to be more alert to take remedial actions, such as increasing the regulating margin to maintain the operating risk at an acceptable level. It should be noted that a reduction in operating risk due an increase in regulating margin will result in an increase in operating cost as the required generation loading will deviate from the economic load dispatch. The CGRR index can be utilized to evaluate the system operating condition of a wind integrated power system. The most economical operating decision would be based on the economic load dispatch. If the calculated CGRR for this dispatch is not within the specified acceptable level, load shall be transferred economically among the generators that can yield larger amount of regulating margin and hence reduce the CGRR.

A study was carried out for unit commitment to serve the total system load of 2613 MW in order to maintain the CGRR within 0.0027. The number of conventional units required to meet the CGRR criterion are shown in Figure 5.12 for different initial wind power conditions. This can be compared with Figure 5.9 which shows the number of units required based on the N-1 criterion. The risk based approach requires more units to be committed when wind penetration level is high, such as one additional unit for 18% IWP and two additional units for 21% IWP.

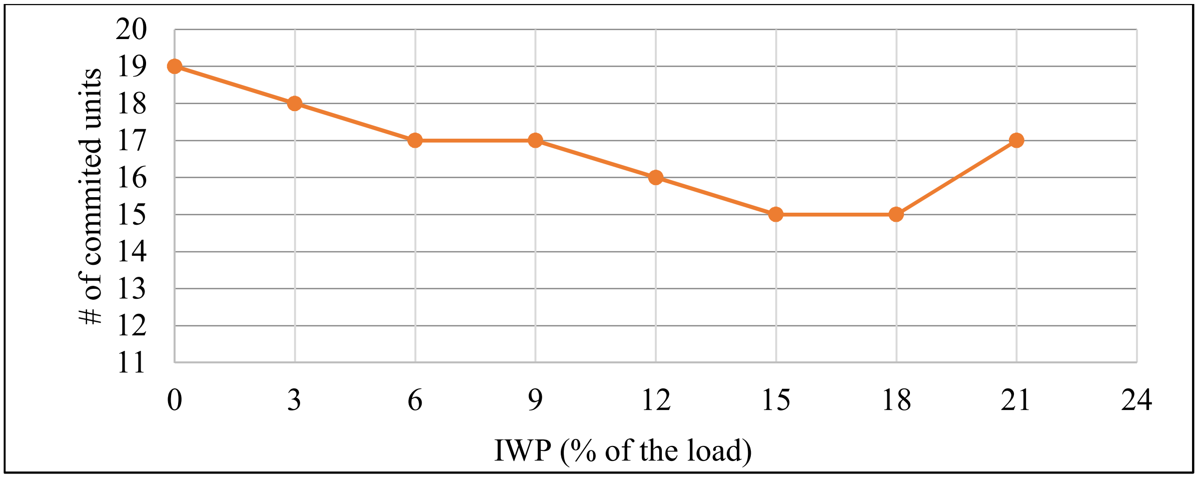


Figure 5.12: Number of units to be committed for risk based dispatch when initial wind power is considered for unit commitment.

The CGRR evaluation technique presented in Section 4.3 is used considering initial wind power as negative load. Figure 5.13 shows the CGRR values at different initial wind power conditions obtained by utilizing the risk based unit schedule presented in Chapter 4. The figure also shows the CGRR from Figure 5.11 obtained using the N-1 criterion for unit commitment without considering initial wind power and the units dispatched based on the ELD approach. It can be seen that the deterministic approach results in a larger variation in the operating risk. Figure 5.11 shows that this variation is more profound when unit commitment is done considering initial wind power.

The operating costs associated with the different operating conditions in this study were also evaluated. The operating cost of wind power is considered to be the system marginal cost [23], which is the incremental cost of the last committed unit from the priority loading order. The results show that the operating cost is increased when the system is operated to reduce the operating risk and maintain the CGRR below 0.002698 in the example operating condition. Figure 5.14 compares the operating costs incurred using the risk based approach with the deterministic approach at different IWP conditions. If the CGRR obtained from the ELD of the committed units is too high in the risk based approach, the dispatch is altered to lower the CGRR to an acceptable level, and results in an increased operating cost.

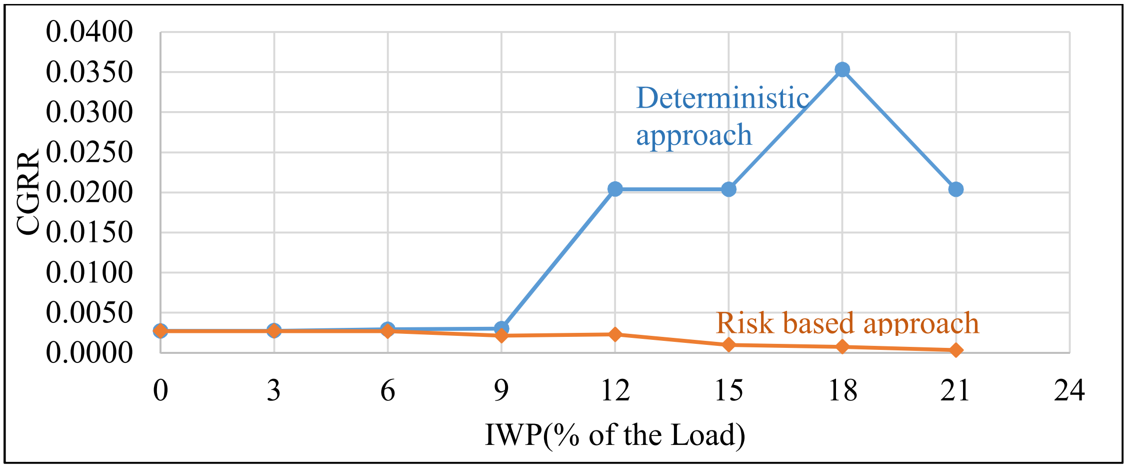


Figure 5.13: CGRR values in risk constrained dispatch.

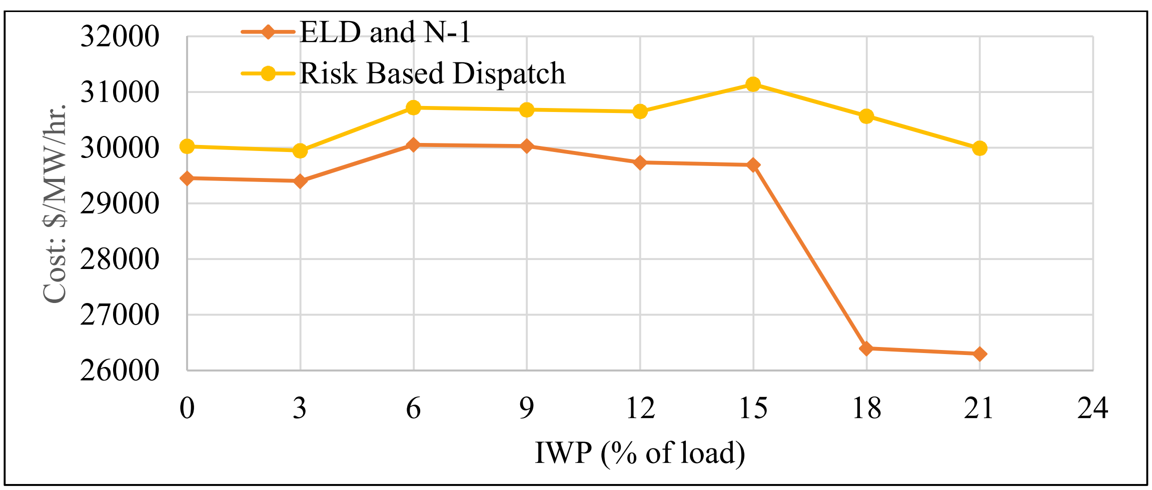


Figure 5.14: Comparison of operating cost in different dispatches.

Figure 5.15 shows the RM for the two approaches for comparison. It can be seen that the regulating margin for the risk based approach is 30% to 66 % higher than that of the deterministic approach using ELD.

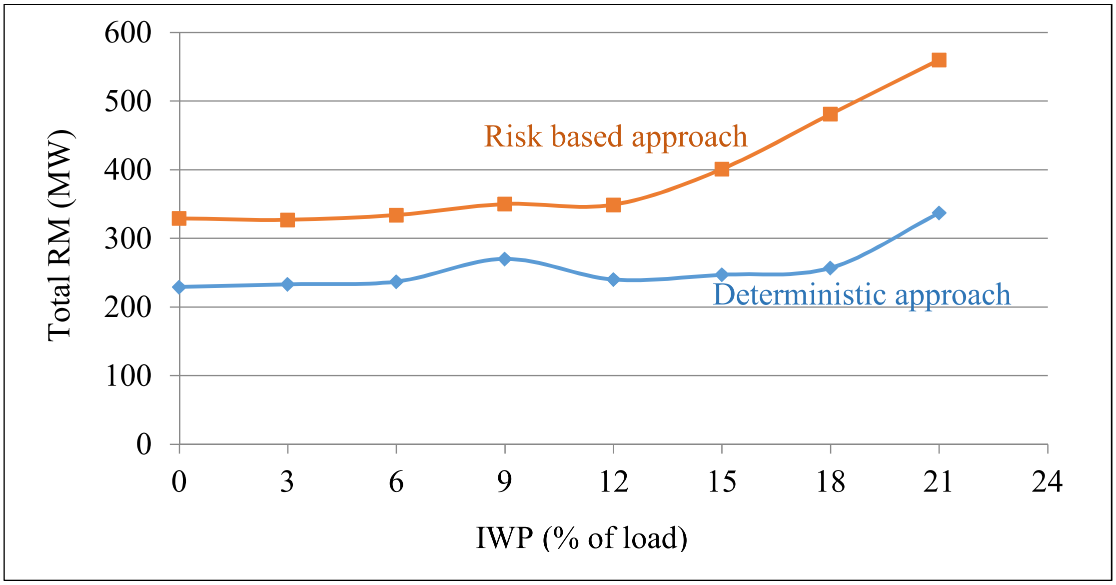


Figure 5.15: Total RM in individual dispatches.

In this particular example, the deterministic method results in higher operating risk and lower operating cost when compared to the risk based approach. The deterministic method, however, may result in lower operating risk and higher operating costs in other operating conditions. In such cases, the excessive operating costs are not justified as the system should be operated as economically as possible with acceptable reliability. The presented risk based CGRR method can be used to ensure that the system operates economically at acceptable level of operating risk. The examples illustrated in this chapter provide useful methodology and valuable information to a system operator to perform appropriate evaluations for the reliable system operation by utilizing CGRR index. The operator can evaluate different operating alternatives to provide a reasonable balance between the operating risk and operating cost before making a final operating decision.

### 5.7 Conclusions

This chapter presents the operating risk evaluation of a wind connected generating system by utilizing the CGRR index. In the first part, a wind power disturbance model is developed to obtain wind variability by utilizing wind speed data in 10 minutes interval from a site of North Dakota, United States. It is found that there is a high probability that the wind power remains unchanged in a short future time. As the probability of the wind power in the short future time depends on the initial wind condition, a conditional probability approach is used to develop the WPD model. The presented study results show that a WPD model represented by small number of states, such as 4, is adequate to evaluate the CGRR with reasonable accuracy for low initial wind power penetration conditions. But for higher wind penetration, it is found that the reduced wind power model gives considerable error. The second part of this chapter presents the application of the CGRR index in wind connected power system operating decisions. Influence on CGRR due to system operating strategy such as inclusion or exclusion of wind power during unit commitment are examined. In deterministic approach, the obtained result show that the unit commitment considering wind gives higher CGRR value as wind replaces the conventional units which are capable of carrying spinning reserve. The proposed risk based operating strategy can be utilized to limit operating risk to a desired level. The cost implication on the risk based operating strategy is also illustrated in this chapter. It is found that the operating cost will be increased if the risk is to be reduced by increasing the regulating margin.

# 6 SUMMARY AND CONCLUSIONS

Power system reliability assessment is an extremely important task in system operation because it provides valuable input to the real time decision making to prevent power outages. Appropriate operating decision can avoid widespread power outages and blackout which can cause adverse impacts to the consumers. Power system operating reliability has conventionally been evaluated using deterministic approach such as maintaining operating reserve equal to or greater than the capacity of the largest operating unit. But this technique is incapable of quantifying the real system operating risk as it does not take considerations of the stochastic nature of component failures or generation and load variations in power systems. This concern has led to the development of the risk based technique which uses a probabilistic approach to quantify the actual system operating risk, and use this quantitative index in decision making. This technique takes consideration of random failures of power system components and generation fluctuations and hence is capable of providing reasonable solutions to maintain consistent risk throughout system operations. Renewable energy sources such as wind power is growing rapidly in power systems because of the environmental concerns associated with the conventional fossil fueled generating systems and the economic incentives available to the investment in renewable energy sources. But the power from wind is highly variable and cannot be regulated at the operator's desire. The random fluctuation of wind power complicates the evaluation of operating reserve and response capacity requirement for reliable system operation.

The UCR and response risk are two major probabilistic risk indices available in literature for operating risk assessment. The UCR evaluation provides information on how many generating units need to be committed for a certain operating condition and lead time in order satisfy an acceptable operating risk. But the dispatch of these committing generators is unknown during unit commitment. The response risk evaluation provides information on the operating risk associated with the distribution of the load and the spinning reserve among these participating units. Although both UCR and response risk analysis are necessary to perform complete operating risk assessment, they are evaluated independently. Since unit ramping capability is not considered in UCR analysis, the unit commitment decision based on UCR may not appropriately address the response risk criteria due to the possible insufficient regulating margin resulting from the low ramp rates of the committing units. To address this problem, a comprehensive risk index that utilizes the both unit commitment and dispatch decisions is proposed in this thesis. This new risk index is designated as the committed generators' response risk (CGRR). The CGRR evaluation procedure, its sensitivity and its applications to the conventional power system as well as the wind integrated power system operating decisions are presented.

In the beginning of this thesis, a brief introduction of power system reliability, the related literature review and the research objectives are presented. Chapter 2 describes the basics of the operating risk assessment. Starting from PJM method, the fundamental of operating reserve risk assessment is presented by mathematical aids related to a six unit example system. The generation model for short term reliability evaluation is developed recognizing its time dependent characteristics and its dependence on the initial conditions. The system load is assumed to be constant during the lead time. The security function approach, an alternative way to evaluate UCR using conditional probability is also discussed in this chapter and the results obtained in analytical method are verified with this method. The basics of the MCS technique is also described in chapter 2.

In chapter 3, a new probabilistic risk index denoted by CGRR is proposed. The CGRR is a comprehensive risk index that covers all possible disturbances within the lead time considered.

The development of the analytical method of evaluating this new index utilizing the conditional probability approach is illustrated. A method to evaluate the CGRR using a MCS technique is also presented in this chapter. The CGRR results obtained using the analytical method developed in this work was validated by using MCS technique. It was found that neglecting contingencies higher than the fourth order disturbances in analytical method significantly reduces the computation and also provides CGRR results with reasonable accuracy. The determination of an acceptable risk parameter generally depends upon the system under study and also is a managerial decision. Chapter 3 also presents a method to determine an acceptable CGRR criterion by benchmarking with the existing criteria currently in use. From the analysis, it is approximated that the acceptable CGRR value for IEEE RTS system is 0.002698. Chapter 3 further includes the sensitivity study of CGRR with unit ramp rate and unit failure rate. It is found that CGRR is highly sensitive to the unit ramp rate than the unit failure rate, and this could be a valuable information for the operator to decide which unit to load fully and which unit to assign with some amount of spinning reserve.

Chapter 4 presents application of CGRR index in power system operation. Six different operating scenarios are presented in IEEE RTS system for a specified load to observe the variations on CGRR, UCR and RM. As unit response capacity is not considered in UCR based unit commitment, that operating scenario could result high CGRR. An algorithm is developed which changes unit commitment and unit schedules that alters the regulating margin and thus maintains a specified CGRR index in an economic manner. The deviation of the unit schedules from the economic load dispatch will increase the operating cost. This information provides valuable inputs while making decisions in power system operating scenarios.

An appropriate wind power disturbance model is necessary to evaluate CGRR index in wind connected power system. Chapter 5 presents a wind disturbance model using conditional probability approach. A WPD model is developed for a site in North Dakota using wind speed data in 10 minutes interval collected over a period of for three years. The CGRR indices for different WPD models are examined to find the appropriate number of state representation for the wind disturbance model. It is found that a reduced state WPD model can be utilized for low wind penetration level, but a higher state model is necessary for higher level of wind penetration. The developed WPD model is utilized to calculate CGRR index in wind connected generating system. The two cases are observed; in the first case the wind power does not replace the conventional units which stay online in a low operating level to absorb the available wind power. In the second case, the wind power is considered in the unit commitment which can make certain number of the conventional generators offline depending upon the wind penetration level. The CGRR index for the first case shows improved system reliability for wind power integration up to a certain level due to the increased spinning reserve of the online conventional units. Beyond this penetration level, the risk index increases as the disturbance of the wind power becomes significant for this operating condition. However, the second case shows a gradual risk increase as the percentage of wind power integration is increased. This is due to the fact that the increased wind power progressively replaces spinning reserve carrying conventional units. A risk based approach can be utilized to operate such system in an acceptable risk level. Chapter 5 also presents a scenario of operating decision of a wind connected power system by utilizing risk based operating strategy.

In conclusion, this thesis presents a probabilistic technique to access operating risk of the power system by introducing a new risk index CGRR. The result of the proposed model is successfully validated by using the MCS. As CGRR captures both the unit commitment risk and the response risk of a particular operating condition, operators can effectively utilize this method to minimize the associated operating risk within the concerned lead time. Different case studies presented in this thesis give realistic operating risk evaluation where important conclusions are deduced. It is found that higher regulating margin is not always an indicator of low operating risk or diversifying regulating margin do not necessarily reduce risk level for all time. Additionally the CGRR index is also utilized for operating decisions in a wind integrated power system. A suitable short term wind power disturbance model is developed using conditional probability approach. The presented case studies show that CGRR criteria represents an appropriate operating risk and can be considered as a reliable index for the system operating decisions in wind integrated power system.

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