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Flexibility and their role in capacity and congestion management

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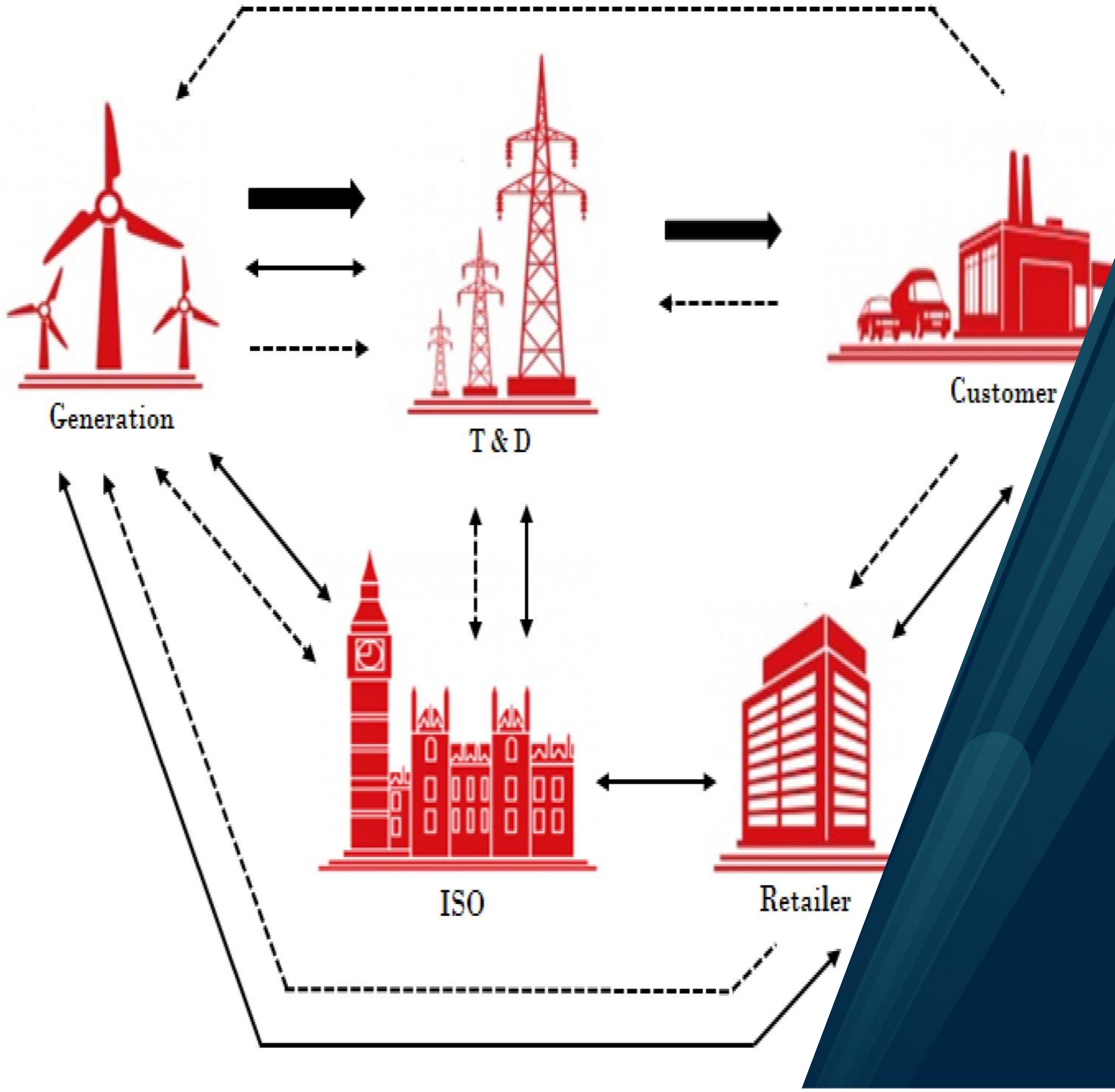

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Abstract

The energy market transition from a regulated power market to a deregulated power market ensures a more liberalized approach toward energy trade as it allows small and medium independent power trading entities to share the market. This provides a competitive environment in the energy market, and market forces also come into action to ensure the balance of the market. With all these advantages, deregulating the market also increases the power system complexity, as new participants are less concerned about the power system planning and more biased towards their profit maximization. One of the major problems faced by power systems in a deregulated model is congestion during power flow. Multiple participants of the market commit to supply energy to the consumers, but the flow of this energy needs transmission capacity. In the case of a power transmission system working near its capacity, it will have less room for newer electricity flow commitment, thus leading to a violation of thermal and voltage constraints in case of increased power flow. This kind of situation means that transmission is suffering from congestion and it is not flexible enough to handle the increased power flow to quench further electricity demand.

By upgrading the system transmission capacity, the system can become more flexible in terms of increased power flow but the investment cost for this is very high, and it is economically not feasible. Traditionally used load shedding technique is also not a solution as it brings down power system reliability. In this study, various ways to mitigate congestion are discussed. This study aims to manage the deregulated power market while prioritizing system reliability and security. The thesis suggests the inclusion of Renewable Energy Sources (RES) in congested systems to fulfill the locational demand causing transmission congestion. The reactive power needed by the system, such as in industrial zones, due to penetration of reactive components, the reactive power supply is ensured via local Flexible Alternating Current Transmission Systems (FACTs) devices. The sizing and placement of these devices are discussed. The study also discusses a backup system where consumers can take part by selling their backup energy in the market during congestion mitigation operation. These techniques are implemented on IEEE standard bus systems to observe congestion management and to increase the flexibility of the power system.

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Abbreviations

RPM	Regulated Power Market
DPM	Deregulated Power Market
TC	Transmission congestion
DGs	Distributed Generation systems
RES	Renewable Energy Sources
FACTS	Flexible Alternating Current System
EVs	Electric Vehicles
DSOs	Distribution System Officer
ISOs	Independent system operators
LMP	Locational marginal price
SCED	Security Constrained Economic Dispatch
OPF	Optimal Power Flow
CDFs	Congestion Distribution Factors
VSCs	Variable Series Capacitors
SPSs	Static Phase Shifters
TCSC	Thyristor Controlled Series Capacitor
UPFC	Unified Power Flow Controller

1 Introduction

Electrical transmission network plays a pivotal role in transferring power generated by sources to the consumers. Due to increased demand, power transmission networks must operate near their full capacities. The situation when the power transmission system cannot transfer power because of transmission lines exceeding their designed capacity is known as transmission congestion (TC) (1-9). Congestion can give rise to various inefficiencies leading to a decrease in system reliability and security. Congestion also makes the system rigid, as it does not keep the system from adapting to the changes in supply and demand, particularly the increase in demand. The ability of the power system to efficiently adjust its supply of energy based on fluctuation in demand is known as the flexibility of a system. This attribute of the system is also responsible for adjustment in the power system, without shedding any load or system damage, in case of any unexpected events or faults. (28-29)

1.1 Background and motivation

Over recent years, increasing electricity needs and technological progress have steered the electrical industry from a Regulated Power Market (RPM) to a Deregulated Power Market (DPM) with different distributed resources. Effectively managing the dispatch of power in the presence of various market participants has become complex.

In the context of DPM, transmission networks face the challenge of operating near system operating constraints. This gives rise to a situation where transmission lines no longer possess the flexibility to increase the power flow through them, in other words, transmission lines suffer from congestion. Congestion in the power system network poses risks to the security as power system equipment will operate beyond its thermal limits which can lead to physical damage to the system. In this situation, a chunk of load can be shed from the power system that will bring down the power flow through the lines preventing them from physical damage. In this way, the system is no longer reliable as it is unable to provide power to its consumers.

The core idea of DPM is to provide a free market environment for non-governmental entities to do the trading. Congestion in the transmission system keeps the market away from fair competition and ultimately leads to monopolies and perturbs the economic stability of the power industry. Effectively handling congestion has emerged as a key responsibility for system operators in DPM, aiming to mitigate issues within the transmission network.

Traditionally, optimal planning for system capacity expansion was employed to counter this problem, these techniques are redundant today. However, there are some non-technical ways to deal with the situations that are still used today. In such cases, the market uses demand response i.e. it provides incentives to the consumer, to encourage them to reduce or shift their energy consumption and needs, during periods of congestion, due to high demand. In the presence of high penetration of Electric Vehicles (EVs), the rescheduling of the vehicle charging is also often proposed.

In traditional solutions, most of the time system is giving up its essential attributes, like reliability, security, and economic optimality. However, the problem can be dealt through the enhancement of the flexibility of the system. As in all the traditional and non-technical solutions, the system lacks flexibility. One way, this can be done is the application of Distributed Generation Sources (DGs) to make power available locally without the need for transmission over long distances. Conventionally, various Flexible Alternating Current Transmission System (FACTS) devices are used in transmission compensation i.e. removing the reactive losses within the transmission lines, but in case of congestion in transmission lines, a larger reactive component package can be deployed on the congested area to cater the reactive power demand.

1.2 Problem statement

Congestion is a common issue in DPM due to the absence of a centralized entity for system planning. Independent System Operators (ISOs) have jurisdictional limitations, yet they play a critical role in ensuring efficient electricity transmission within their designated areas. However, the influence of individual ISOs extends to the entire power system. Market participants aim to maximize benefits, but they lack the authority to regulate the entire system comprehensively. This results in multiple participants operating independently within the market, leading to simultaneous energy delivery to meet the demand, and causing Transmission Congestion (TC). TC can result in power outages and compromise the reliability and security of the power supply. Our research is carried out in two parts. In the first part, simulations are done on smaller systems to understand the concept, and in the second part, larger systems are simulated and analyzed. Specifically, we will focus on enhancing system’s flexibility and capacity to address congestion more effectively.

1.3 Objectives

This thesis covers the following objectives:

- Literature Review of congestion management techniques
- Analyzing various flexibility enhancement techniques and their role in congestion management
- Studying and simulating small bus system i.e. 3 bus system
- Studying and simulating large bus system i.e. 30 bus system
- Suggesting an optimal solution for system chosen

1.4 Sections of the thesis

The thesis comprises of various sections discussing literature, simulations and their results.

- **Introduction:** This section has discussed the background of the problem of congestion in power systems and the motivation for the solution of this problem. The problem is summarized in the form of problem statement. The section also provides the research objectives of this thesis along with a brief overview of sections of the thesis.
- **Theory and Literature survey:** This part provides a detailed overview of non-technical and technical methods used to manage congestion in power system. This section will also discuss the attribute of flexibility and its role in managing congestion in the power system.
- **Methodology:** This section covers the details of processes and methodology used for the management of congestion. These are depicted with the help of flow diagrams to understand the methodology.
- **Simulations of methods:** This section provides the simulations of methods explained in the previous section. It will include case studies where the simulation models are used to create congestion scenarios and techniques are used to mitigate the congestion. Thus, enhancing flexibility.
- **Results and discussion:** This section covers the discussion of the results obtained from the placement of DGs in the system. Additionally, it explores the control strategy for alleviating congestion and suggests limitations and future research directions in this area.
- **Conclusion:** This part concludes the thesis by summarizing the work done in this thesis.

2 Theory and Literature survey

2.1 Congestion in power transmission

Congestion occurs when the demand for the transmission line's capacity exceeds its available capacity. This leads to limitations on the amount of electricity that can flow through the line, potentially causing inefficiencies, increased costs, and challenges in maintaining the reliability of the power system. Congestion often arises due to high demand, inadequate transmission infrastructure, or constraints on the power grid. Mathematically, limits of the line over loading defines the Transmission Congestion (TC) constraints. Violating these limits will result in congestion on the line [1-9]:

$$\left|Pl_{ij}\right| \leq Pl_{ij}{}^{max} \qquad 2.1$$

In (2.1) Pl is the flow of power in line between bus i and j.

2.2 Electricity market

An electricity market in a power system serves as a platform where participants engage in buying and selling electricity. It facilitates the trading of electrical energy among various entities, including generators, suppliers, consumers, and sometimes intermediaries. The main goal of an electricity market is to efficiently allocate resources, determine prices, and ensure the reliable supply of electricity to meet the demand. Within these markets, regional markets can function as submarkets. Androcec et al [1] provides two types of electricity market trades within Europe. These include implicit trade that are done within the regional market and explicit trade that are done inter region. This study will further discuss the congestion management methods using these trades.

2.2.1 Power Market models

The energy market is commonly divided based on transaction regulations. RPM represent the traditional model, where utilities maintain vertical integration, and prices are typically determined by regulatory authorities. These markets often comprise of Conventional Power Systems (CPS), characterized by vertical integration from generation to end-load distribution, overseen by a single regulatory unit. This regulatory oversight ensures a fixed price for customers in the market, regardless of their location.

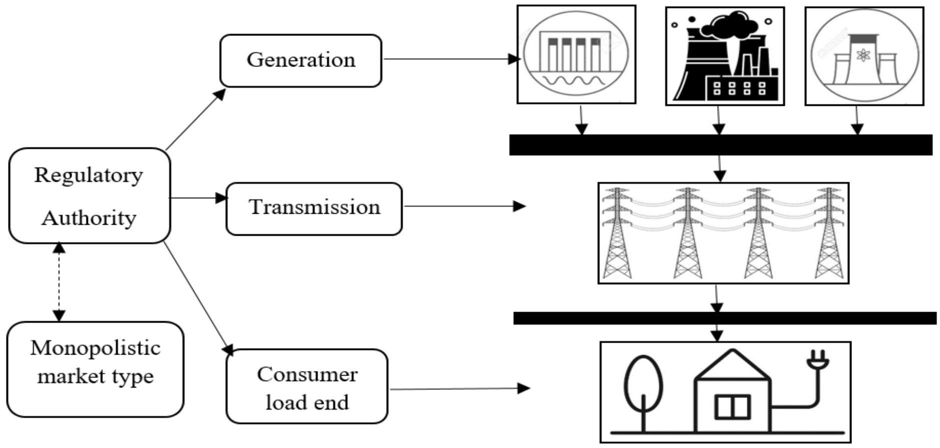

Figure 1: Regulated Power Market

DPM, also known as competitive or liberalized markets, operate with separate entities for generation, transmission, and distribution with prices determined by market forces. This system operates on an open-access basis, facilitated by system operators who initiate transactions, responding to supply and demand dynamics. Unlike RPM this model lacks the fixed pricing strategy. Each generator operates according to its own cost function, typically represented by a cubic curve. However, this situation will give rise to an increased demand from private large-scale consumers, to be connected to low rated generation units. Consequently, this will give rise to congestion in that transmission line.

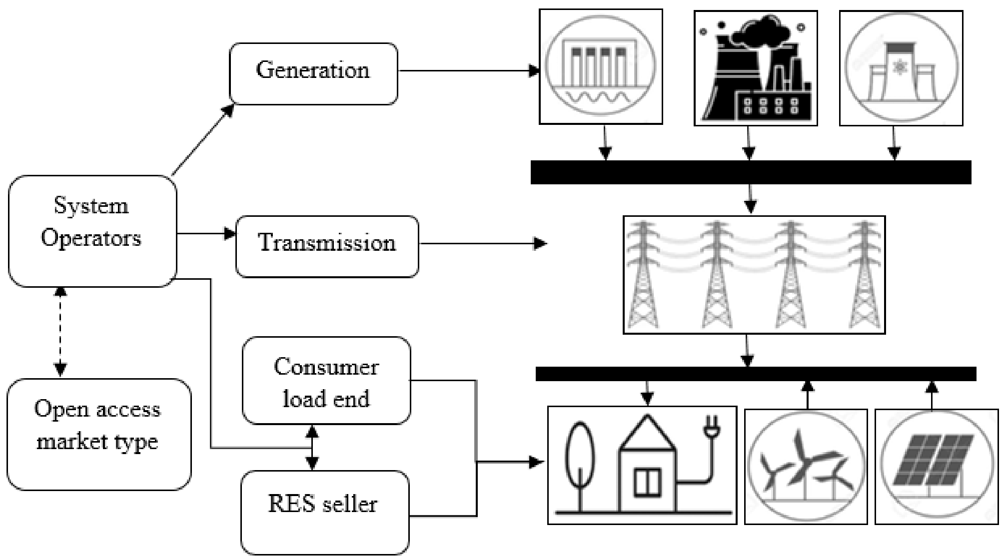

Figure 2: Deregulated Power Market

2.2.2 Role of Power Market

Electricity markets play a crucial role in promoting competition, optimizing resource utilization, and achieving cost-effective power supply within modern power systems. The specific design and operation of these markets can vary significantly between regions and countries.

Transmission lines are bound by constraints with a minimum power limit $P_{T(min)}$ representing the lowest allowable power transmission quantity, below which operation is not feasible. Similarly, there is a maximum limit $P_{T(Max)}$, beyond which the line is considered congested. In the event of a fault on any other branch, spare capacity is not available, thereby reducing the flexibility and security of the system.

Currently, transmission congestion poses a significant challenge within deregulated power systems, leading to fluctuations in electricity prices. This challenge stems from insufficient system capacity to meet the demands of all consumers and the utilization of more expensive generation units. Consequently, this hinders the effective functioning of electricity markets in fostering competition. As a result, congestion management has emerged as a pivotal concern in ensuring the secure and reliable operation of electricity markets [1-5].

2.2.2.1 Congestion in Deregulated Power Market

DPM introduces several challenges such as devising auction strategies for electricity, mitigating transmission congestion, upholding system reliability and security, and evaluating market equilibrium [2]. The flow of power between different locations in the transmission network is constrained by the security and operational limitations of the power system. Transmission congestion occurs when any one of these constraints is violated [3].

2.2.2.2 Causes of congestion

The occurrences of congestion in a DPM is significantly higher as compared to monopolistic power market. The primary causes being unexpected failures in any generator, line outages, malfunctions in system components, unscheduled power flows in transmission lines, and the unavailability of lines for power flows. Challenges in establishing new transmission networks, due to right-of-way issues, financial constraints, and a substantial increase in wheeling transactions associated with restructured power markets, have raised concerns regarding maintaining system security for both system operators and market administrators.

The presence of congestion in the transmission network can result in additional blackouts, disrupt both existing and new transactions between market participants, elevate prices in specific areas of the energy market, impede energy market trading, and pose a threat to system security and reliability. Moreover, transmission system congestion serves as a hindrance to achieving ideal competition among participants in DPM [4].

2.3 Congestion Mitigation techniques:

Congestion mitigation techniques refers to strategies and measures employed in power systems to alleviate or manage congestion on transmission lines. Congestion occurs when the demand for transmission capacity exceeds the available capacity, potentially leading to reliability issues and constraints on the power grid. Various techniques are implemented to address congestion and ensure the efficient operation of the power system. Usually, congestion mitigation is done in two ways. Either by using market variables i.e. non-technical methods or by using power system variables i.e. technical methods.

2.3.1 Non-technical Methods for Congestion Management

Non-technical methods for congestion management refer to strategies and approaches that do not involve physical changes or enhancements to the power system's infrastructure. Instead of relying on technical upgrades to transmission lines or grid components, these methods primarily focus on market mechanisms, economic incentives, and operational strategies to alleviate congestion. These aim to optimize the utilization of existing infrastructure and ensure the efficient functioning of the power market. Examples include market-based mechanisms, pricing strategies, and demand-side management initiatives. These approaches are often more flexible and can be implemented without any major physical modifications to the power system. Some of the approaches are discussed as follows.

2.3.1.1 Market Bifurcation and Load Curtailment methods

The Market splitting method involves dividing the market into regions with limited capacity for power exchange. The methodology first offers an energy pool price based on the demand and supply of the regions; this price is offered to the whole market. This price considers the unconstrained-load demand for calculation. Subsequently a load flow analysis is conducted to identify congestion in transmission lines. After this the areas connected by those lines are separately assigned to a different pool price, which differs from the price offered to the entire market. At this point the market is split into multiple pools. These areas will experience higher demand with all the connecting lines operating at their full capacity. The new pools defined in this situation are arranged so that areas supplied by congested lines will have higher prices, while areas supplying power will have lower prices.

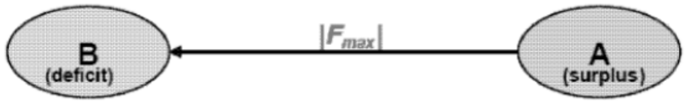

Figure 3: Power Flow from area A to B while transmission congestion

In Figure 3, area A has a surplus while area B has a deficit of power. Subsequently, the line joining these areas is operating at $|F_{max}|$ i.e. at its limit, hence following [1] region B will have a higher price than region A. Norway employs this method, allowing power procurement for supply from low-priced regions to higher-priced ones. The load curtailment approach manages loads to alleviate congestion, aiming for minimal curtailment and price reduction in congested regions, using the "willingness to pay" factor as an efficient curtailment tool [1]. Additionally, the profits from the market splitting method can be used to expand the transmission capacity.

2.3.1.2 Nodal pricing method and Locational Marginal pricing

Nodal pricing, a prevalent CM method in DPM, involves determining the cost at each location, known as nodal price. Locational Marginal Price (LMP) at a bus reflects the expense of providing additional load, encompassing energy supply costs, losses, and potential congestion costs [6]. It is defined as a product calculated by a constraint based economic dispatch and formulated as below:

$$\min_{p} C^T P \tag{2.2}$$

$$e^T(P - D) - loss = 0, \quad (\lambda > 0) \tag{2.3}$$

$$T(P - D) \leq F^{max}, \qquad (\mu \leq 0) \tag{2.4}$$

$$P^{min} \leq P \leq P^{max}, \qquad (\eta^{min}, \eta^{max} > 0) \tag{2.5}$$

Here (2.2) describes an optimization problem where the objective is to minimize the scalar product of the transpose of cost matrix C and vector P that defines the outputs of generators. Following this, equation (2.3) represents a constraint in the Securely Constrained Economic Dispatch (SCED) problem, ensuring that the total power generated matches the total demand while accounting for transmission losses. (P-D) represents the difference between supply and demand, multiplied by a vector to define the term at each unit. The goal is to ensure that the difference between this term and the load is zero, effectively balancing generation with demand. Additionally, λ, the Lagrange multiplier, is often used to enforce non-negativity constraints or to penalize violations of constraints. Equation (2.4) provides realistic representation of tie-line flow constraints in the Optimal Power Flow (OPF) formulation, T represents the matrix of Generator Shift Factors (GSF), which quantify the effect on power flow at buses in the system due to a small change in generation at one generator bus. The product of T and the difference between power supply and demand should be smaller than F_{max}, which represents the maximum tie-line flows. Lastly (2.5) defines the upper and lower limits of power generation at each unit. By solving the partial derivative of the lagrangian of these constraints with respect to the demand on each bus, the LMP of that bus can be obtained [6].

$$L = C^T P - \lambda(e^T(P-D) - loss) - \mu^T(T(P-D) - F^{max}) + \eta^{max}(P - P^{max}) + \eta^{min}(-P + P^{min}) \qquad 2.6$$

Equation (2.6) merges equations (2.2-2.5) with their constraints as lagrangian multipliers. The equation will simply minimize the cost $C^T P$ while keeping all the constraints in view. By taking the partial derivative of this lagrangian with respect to demand will provide the locational marginal price. This defines, the change in the energy cost required to efficiently supply an additional unit of load at a specific location, ensuring that no constraints are breached.

$$\lambda_i = \frac{\partial L}{\partial D_i} \qquad 2.7$$

Here i represents the number of buses where the LMPs are calculated.

The LMP-based CM approach is globally adopted for its efficient allocation of transmission capacity, preventing network congestion. In a normal vertically integrated system (comprising generation, transmission and distribution units), economic dispatch is typically used to minimize the cost of production. However, this approach does not account for flow constraints, leading to congestion. To address this issue, the OPF technique is employed. OPF incorporates power flow constraints and solves the optimization problem while ensuring compliance with these constraints, thereby minimizing congestion. Congestion generally results in unequal and high locational marginal price at different buses, which in turn leads to low revenues. To tackle transmission issues, the Independent System Operators (ISO) optimally manages the power system by responding to congestion price signals at specific locations [7].

$$C_i = a_i + b_i.P_i + c_i(P_i)^2 \qquad 2.8$$

The equation (2.8) gives the cost function of i^{th} generator. With some constraints we can calculate optimality, if the cost function described is differentiated and a lagrangian multiplier is added. For each cost function of generator ‘i’ the result will be:

$$b_i + c_i P_i = \lambda \qquad 2.9$$

Here ‘b’ and ‘c’ are cost coefficients as described in the cost function. While for a lossless case we can give a power balance equation as:

$$\sum_{i=0}^{n_g} P_i = ones(1, n_g).P = P_D \qquad 2.10$$

Upon solving the equation (2.9) for all the buses we can conclude the following linear matrix problem.

$$diag(c).P - ones(n_g, 1).\lambda = -b \qquad 2.11$$

Here, 'b' and 'c' are the same cost coefficients but in the form of vectors, with 'P' representing the vector for describing power generation. In certain situations, congestion occurs, and these costs might not be the same across all locations or sources of electricity generation, even when considering ideal conditions without any energy losses during transmission. This means that producing an additional unit of electricity at one location might be more or less expensive compared to another location. Despite these differences in costs, it's still possible to achieve an optimal distribution of power across different locations by adjusting the prices associated with each location. These prices are called additive prices β.

$$diag(c).P - ones(n\_g, 1).\lambda = -(b + \beta) \qquad 2.12$$

The additive prices help achieve the best possible allocation of power resources across various locations, ensuring that the overall cost is minimized while meeting all necessary constraints and requirements. These prices act as adjustments that balance out the differences in marginal production costs, leading to an efficient and cost-effective distribution of electricity. Additive prices are calculated once the system is solved without any constraints. Thus, the LMP-based congestion management system [7] includes three steps that any ISO can follow to alleviate congestion in the system.

1. Solve the system as an OPF problem, while considering various constraints such as generator limits, transmission line capacities, and demand requirements.
2. Determine prices β to relieve congestion i.e. the ISO calculates prices (referred to as nodal prices or locational marginal prices) that can be applied to specific locations within the power grid experiencing congestion.
3. ISO communicates the calculated price β to market participants, such as power generators, consumers, and traders, through market mechanisms like auctions, bids and contracts.

Similarly, in [8], an approach based on DC load flow is employed to compute optimal bus prices and congestion costs.

2.3.1.3 Cluster Pricing Method

The method described in [9] manages transmission congested areas by categorizing system users into distinct groups known as congestion clusters. These clusters classify consumers based on their impact on specific parts of the power system. By organizing users in this manner, it becomes easier to identify potential issues and devise solutions. Congestion clusters are formed based on the magnitude and distribution of user effects on transmission constraints. Type 1 clusters consist of users with significant and uneven effects, whereas Type 2 clusters consist of users with smaller and more evenly distributed impacts, and so forth. These clusters provide insights into user behavior concerning transmission constraints.

One can easily understand this through an analogy of traffic on the highway. Imagine a highway where traffic can get congested at certain points. Now, instead of viewing traffic as a whole, the highway is divided into congestion clusters. These clusters group the cars based on their proximity and impact on congestion. For instance, cars near congested areas have a substantial impact, while those farther away have less influence. Clusters are determined by analyzing each driver's contribution to congestion and grouping them accordingly. Drivers within the same cluster exhibit similar effects on congestion, while those in different clusters have differing impacts.

To group system users into congestion clusters, Congestion Distribution Factors (CDFs) are employed. These factors quantify the impact of each power transaction on a transmission constraint. CDFs are essential tools that help understand how the flow of power on a line changes when power is injected at different points in the system. Mathematically, the CDF on line 'y' can be expressed as:

$$CDF_y = \frac{\Delta P_{mn}}{\Delta P_m} \tag{2.13}$$

Here ΔP_{mn} is the change in power flowing between bus m and n and ΔP_m is the change in power injection on bus m. In the study presented by [9] only the transactions within cluster 1 have a great impact on congestion, where the CDFs are large and uneven.

When the CDF for a specific bus is positive, it implies that injecting power at that location will amplify the flow along the associated transmission line. This increase in flow can increase congestion, much like adding more vehicles to an already crowded roadway. Conversely, a negative CDF signals that injecting power at the designated bus will mitigate congestion along the line. CDFs diminish with distance from congested areas, making users aware of their contribution to congestion. This simple concept aids in calculating transaction impacts across clusters, useful for trading transmission rights and managing usage-based congestion fees.

2.3.1.4 Various Countries approach towards Congestion management

The three approaches in managing deregulated power systems include the optimal power flow model (used in the UK, parts of the US, Australia, and New Zealand), the point tariff pricing (applied in Norway and Sweden's Nord pool market), and the US transaction-based model [10].

1. **Optimal Power Flow Model:**

   The OPF model is a mathematical optimization technique used to determine the optimal operation of the power system while satisfying various operational constraints, including line capacities, generator limits, and voltage constraints. The OPF model in the UK may incorporate additional features such as Locational Marginal Pricing (LMP), which assigns prices to different locations on the grid based on congestion levels. LMP helps provide economic signals to market participants, encouraging efficient use of the grid and investment in congestion-relief measures.

2. **Point Tariff model:**

   A "point tariff" is a type of transmission tariff where each generator and consumer pays a fee based on their connection point to the grid. This means that the fee varies depending on the generator's or consumer's location within the grid. In Norway, the transmission tariff system is similar to that of Sweden and Finland, where users pay fees to access the electricity grid at different levels: national, regional, and local. These tariffs help cover the costs of maintaining and expanding the grid infrastructure. Like Sweden and Finland, the market adjusts the capacity charge, depending on the location of the energy seller. If the energy supplier is in an area with higher demand (such as in the north), the supplier might pay less. However, if the supplier is in an area with more supply (like in the south), the supplier might pay more. This approach is intended to incentivize generators to set up where they are needed most and for consumers to use power where it is available, ultimately helping to alleviate congestion on the grid.

3. **Transaction-Based model:**

In a transaction-based model for managing congestion on electricity grids, the emphasis is on how energy is bought, sold, and traded between different parties, rather than directly controlling the flow of electricity on specific lines. Here's how it works: Instead of dictating where generators or consumers should send or receive power, the market allows them to make decisions based on prices and incentives. When congestion occurs, indicating excessive demand on certain lines, prices in those areas rise. This incentivizes consumers to reduce their electricity usage or shift their transactions to locations where it's cheaper. To ensure smooth operation, regulators establish rules and regulations and monitor the market to prevent unfair practices or disruptions. This approach enables the market to efficiently manage congestion while providing participants with the freedom to make their own choices about electricity usage. When the U.S was deregulating its electric power system, a challenge arose due to the predominance of private companies controlling power generation under state regulations. Instead of imposing strict rules, the government encouraged competition and allowed regions to develop their own approaches.

Nord Pool manages congestion in its power exchange for Nordic wholesale electricity through a series of markets. The Elspot market facilitates contracts between suppliers and consumers based on expected generation and consumption. Adjustments are then made in the Elbas Intra-day market and the intra-hour regulating electricity market. In Nord Pool, congestion management relies on cross-border capacity allocation in the Intra-day market, with Available Transfer Capability (ATC) playing a crucial role in addressing capacity limits within an hour before regulation. [11].

2.4.2 Technical Methods for Congestion Management

Technical methods for congestion management involve physical or engineering solutions to address limitations in the transmission or distribution of electrical power. These methods aim to enhance the efficiency and reliability of the power system by upgrading, expanding, or optimizing the existing infrastructure. Some common technical methods for congestion management include:

2.4.2.1 Congestion management by transmission line upgrade:

Transmission Line upgrade increases the capacity of existing transmission lines by upgrading conductors, insulators, or other components. However more emphasis is put on the maintenance of the transmission line system. Mostly the equipment that undergoes any kind of damage is changed as soon as the problem is detected. Another method is constructing new transmission lines to alleviate congestion and enhance the overall capacity of the power grid. However, it is not easy as it requires a lot of funding and legal work to get the right of way. Usually for congestion management this is not suitable as new transmission lines are constructed to energize new distribution units. For mitigation of congestion this approach may over do the correction.

2.4.2.2 Flexible AC Transmission Systems devices (FACTS) for Congestion Mitigation

Congestion management through FACTS devices is a technical method employed to address congestion on power grids. FACTS, or Flexible Alternating Current Transmission Systems, encompass specialized equipment installed on power lines to enhance the control and efficiency of electricity transmission. These devices dynamically adjust the voltage, impedance, and phase angle of power lines, allowing for the redirection of power flows, relief of congestion on heavily loaded lines, and optimization of existing transmission infrastructure utilization. This increased flexibility enables operators to better manage grid congestion, ultimately improving overall system reliability. Enhanced flexibility ensures improved Available Transfer Capability (ATC), decreased congestion costs, and compliance with contractual requirements. An optimal placement of FACTS devices, such as variable series capacitors and static phase shifters, is crucial for effective grid management.

Just like any generator cost function, the cost of installing variable series capacitors involves two main factors: the installation cost and the capital cost of the capacitor itself. The installation cost is fixed and doesn't change based on the capacitor's properties. However, the capital cost of the capacitor depends on its reactance, which is a measure of how much compensation the circuit needs. In simpler terms, the bigger the reactance of the capacitor, the more it costs. This makes sense because larger capacitors require more materials and resources to produce. Mathematically, [12] provides the cost function of each series capacitor using the formula:

$$C(Q_{cap}) = b_0 + a_0 Q_{cap} \tag{2.14}$$

Where Q_{cap} represents the reactive power of the capacitor (per unit), a_0 is a positive constant coefficient that represents how much the cost increases with the reactance and b_0 is the fixed installation cost. Similarly, the total cost for the installation throughout the system can be calculated by:

$$C_{cap} = \sum_{i=1}^{n_{cap}} C_i(Q_{cap}) \qquad 2.15$$

Here C_{cap} is the total cost of capacitors that are installed, n_{cap} is the total number of capacitors that are installed throughout the system and finally $C_i(Q_{cap})$ is the cost of a specific i^{th} capacitor at any location providing Q_{cap} reactive power.

For any transmission line there is an equation for power flow that represents the transfer of power between any two buses, denoted as i and j for instance. This equation depends on the voltage magnitudes of buses i and j along with the line reactance and angle difference between i and j. So, we can mathematically write:

$$P_{ij} = \frac{V_i V_j}{X} \sin \delta \qquad 2.16$$

Introducing capacitance into a transmission line serves to reduce its overall impedance. This effect is particularly beneficial for improving the performance of the specific transmission line in question. By decreasing impedance, the addition of capacitance contributes to enhancing the line's efficiency and reliability in power transmission.

$$P_{ij} = \frac{V_i V_j}{X - X_C} \sin \delta \qquad 2.17$$

Here in both equations, P_{ij} represents the power flow over a line from bus i to bus j, V_i and V_j are the voltage magnitude at bus i and j, while X is the line reactance and X_C is the reactance of the series capacitor, and finally δ represents the angle difference between the buses. Increasing the series compensation in a power system means adding more series capacitors. This helps the system move electricity more effectively, allowing transmission lines to handle more power. It's like upgrading the system to work better but it's not free, adding more capacitors costs money. Investment is needed for the equipment and its maintenance. So, while it makes the system more efficient, it also means spending more on equipment and infrastructure. It's a trade-off between making the system better and the cost of doing so. Apart from this the variable series capacitors [12] also provide the method of enhancing transmission capacity and system flexibility through Static Phase Shifters (SPS)

$$C(\alpha) = d \qquad 2.18$$

Where d is a positive constant that is only the installation cost. So, for the total system it can be represented as:

$$C(\alpha) = \sum_{i=1}^{n_\alpha} c_i(\alpha) \qquad 2.19$$

Here C(α) represents the total cost of installation of SPSs over the whole system, $n_\propto$ is the number of SPS unit installed and $C_i(\alpha)$ represents the capital for installing i^{th} SPS.

Recent advancements in high-power electronics have made FACTS devices more practical, leading to their increased usage in DPM for managing power transactions and relieving congestion. Optimal placement of FACTS devices is crucial for their effectiveness in congestion management, with various studies exploring their impact on congestion, spot prices, and network bottlenecks. [13] provides the congestion management through more dynamic devices such as Thyristor Controlled Series Capacitor (TCSC) and Unified Power Flow Controller (UPFC).

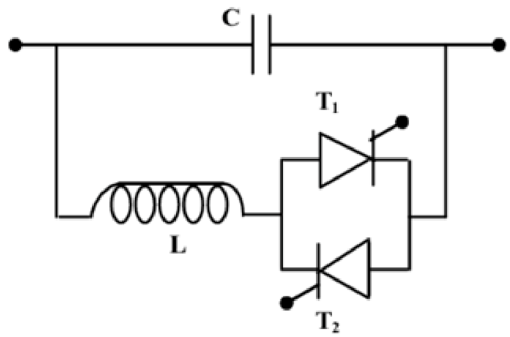

Figure 4: Equivalent Circuit of Thyristor Controlled Series Capacitor (TCSC) [13]

The circuit diagram of TCSC presented in Figure 4, shows that the device provides a different reactive element to the circuit based on the switching of T1 and T2. Therefore, a TCSC is a type of FACTS device that can change its reactance or impedance based on system conditions. Reactance can be thought of as a measure of how much a component resists the flow of electricity. By adjusting the reactance, TCSC can influence the flow of power through a transmission line. Kumar et al [14] provides the technique for mitigation of congestion in a system using FACTS devices, along with the simulations for two FACTS devices.

2.4.2.3 Congestion management by Generation rescheduling and Load shedding

Generation Rescheduling (GR) is a widely employed technique for CM in DPM. When transmission bottlenecks occur, adjusting generator outputs helps alleviate congestion. GR is particularly crucial in pool markets, minimizing deviations in market settlements. However, it may increase operating costs, necessitating careful scheduling to minimize deviations from monetary agreements.

Load shedding is another method used in case of persistent congestion, achieved by reducing load demand to attain a congestion-free state. Mathematical models, employing methods like Newton-Raphson and fast decoupled load flow, addresses line overload through GR and load curtailment [15].

Norway's DPM utilizes GR with varying durations to manage congestion effectively [16]. For this purpose, the focus of the study was generation scheduling, which involves determining the optimal operation of power plants to meet electricity demand while minimizing cost. This includes considerations such as unit commitment (deciding which generators to operate), economic dispatch (allocating generation to minimize costs), and real-time adjustments to respond to fluctuations in demand and supply. The study also includes a stochastic model for future market that is used for long, medium, and short-term forecasting of spot market prices.

2.4.2.3 Distributed generation strategy for Congestion management

Distributed Generators (DGs), especially Renewable Energy Sources (RES), play a crucial role in mitigating congestion by reducing power flows on specific transmission lines, particularly in technologically advanced smart grids. Strategic placement and operation of DGs in DPM contribute to deferring or eliminating transmission congestion, improving voltage profiles, minimizing losses, reinforcing the grid, and enhancing overall smart grid efficiency and reliability.

Singh et al [17] provides a strategy for the placement of distributed generation systems in presence of different kinds of loads. Three kinds of loads are modeled in this study, a constant power load model, residential power load model and an industrial power load model. It is observed that as more load deviates from constant model, there is a significant decrease in the overall influence of P_{intake}, Q_{intake} and S_{intake} on total power system due to the introduction of DGs. The MVA of the system is given by the following equation (2.20)

$$MVA_{System} = \sqrt{(P_{intake} + P_{DG})^2 + Q_{intake}{}^2} \quad 2.20$$

Where MVA_{system}, represents the total power which is composed of real power (P_{intake}), power from DG (P_{DG}) and reactive power (Q_{intake}) in the system. The DG should be placed near loads, but this can violate the distribution system constraints. So, there is an index presented to keep the MVA capacity inbound.

$$Ic = 100 \times max_{i=1}^{n}\left(\frac{\left|\overline{S_{ij}}\right|}{\left|\overline{CS_{ij}}\right|}\right) \quad 2.21$$

In equation (2.21), Ic represents the Capacity index, $\left|\overline{S_{ij}}\right|$ denotes MVA intake at line i-j and $\left|\overline{CS_{ij}}\right|$ represents the MVA capacity of the line. While, the MVA capacity index is expressed as a percentage, lower values of the index indicate that there is more capacity available in the network. Suggesting that the conductors are not being utilized to their maximum capacity. On the other hand, index values above 100% indicate an overloaded condition, resulting in MVA flows exceeding the maximum capacity of the conductors. Such situations require immediate attention to prevent equipment damage or power outages. Utilities and operators utilize the MVA Capacity Index to plan and prioritize system upgrades and maintenance activities. By monitoring the index over time, they can identify areas of the network experiencing high levels of stress and take proactive measures to address potential issues before they escalate.

Similarly, real and reactive power loss indices are measured to assess the impact of DG on reducing power losses in a system.

$$I_{LP} = 100 \times \left(\frac{|\overline{P_{LDC}}|}{|P_L|}\right) \quad 2.22$$

$$I_{LQ} = 100 \times \left(\frac{|\overline{Q_{LDC}}|}{|Q_L|}\right) \quad 2.23$$

I_{Lp} and I_{LQ} represent the percentage of real and reactive power losses. The I_{Lp} and I_{LQ} are calculated by comparing the power losses caused by DG (P_{LDC}) to the total power losses in the system (P_L). Lower values of I_{Lp} and I_{LQ} indicate more significant benefits in terms of loss reduction achieved by placing and sizing distributed generation within the system. Essentially, if I_{Lp} and I_{LQ} are low, it means that the DG is effectively reducing the overall power losses in the system. In addition to I_{LP} and I_{LQ}, there is another index related to voltage drop known as the Voltage Profile Index (IVD). The Voltage Profile Index (IVD) represents the maximum voltage drop in a power system. It checks how much the voltage decreases as one moves away from the main power source, called the root node. This index helps in identifying areas where the voltage drops excessively, which are not suitable for adding DG. Lower values of IVD indicate better network performance because it means the voltage drop is minimal. The formula for IVD is given as:

$$IVD = 100 \times max_{i=2}^{n}\left(\frac{\overline{V_1} - \overline{V_l}}{\overline{V_l}}\right) \tag{2.24}$$

In summary, the study [17] ensures effective congestion management in three different load models with the help of the following steps:

1. The study explores the number of voltage limit violations, aiming to reduce instances where voltage exceeds safe limits to prevent equipment damage and instability.
2. Detection of the number of line limit violations on transmission lines is conducted, as these violations define congestion. The goal is to minimize power flow exceeding line capacity to prevent strain and potential outages.
3. Calculation of MVA, real, and reactive p.u. demand on the main substation is performed. This step aims to manage power demands efficiently to ensure adequate supply and resource utilization.
4. The study measures loss reduction in real and reactive power using the indices presented in the research. Decreasing power losses during transmission is crucial for improving system efficiency and achieving cost savings.
5. Saving of MVA capacity on the distribution substation is ensured by the capacity index. This step aims to optimize power distribution to delay costly upgrades and enhance system reliability.
6. The study locates the optimal location and size of DG by calculating the indices and determining the respective configuration for optimal placement.

DGs play a crucial role in extremely congested systems with elevated LMPs. In such scenarios, DGs can meet local energy demands, effectively reduce energy prices, and alleviate strain on the energy grid. However, careful consideration of DG sizes and locations is essential for optimizing their benefits and avoiding potential risks to system operation. Gautam et al [18] discusses an objective function containing a mathematical modeling of pricing as follows:

$$SW_{max} = max\sum_{i=1}^{N}(B_i(P_{Di}) - C_i(P_{Gi})) - C(P_{DGi}) \tag{2.25}$$

In this equation the three prices are quadratic, $B_i(P_{Di})$ represents the quadratic curve of benefit harvested by the buyers of energy, while $C_i(P_{Gi})$ and $C(P_{DGi})$ represent the quadratic curve of cost function by sellers and distributed generation suppliers, respectively. Overall, this is an equation that is maximizing social welfare.

Various methodologies, such as the highest LMP and LMP difference methods [19], are introduced to determine the optimal location and size of DGs in restructured power systems, thereby mitigating transmission congestion and enhancing system security. Sarwar et al [19] propose a new approach for managing congestion in DPM, based on locational marginal prices. LMP reflects electricity prices at specific points in the grid, which increases with increasing congestion on transmission lines. The difference in LMP prices between two buses indicate the level of congestion, with higher difference signaling greater congestion.

$$\Delta LMP_{KL} = LMP_K - LMP_L \qquad 2.26$$

Zones are defined based on the difference in LMP prices between buses. The most congested zone comprises of buses connected by lines with high and varying LMP differences, while other zones exhibit lower LMP differences. After identifying zones, congestion is managed by strategically placing distributed generation (DG) at potential locations within the congested zones. This helps alleviate congestion by reducing demand on heavily congested lines.

The optimal placement of DGs, based on bus impedance matrix (Z-bus) contribution factors, is explored for congestion management in competitive power systems [20]. This approach explains the methodology of DG placement using DC Optimal Power Flow (DCOPF), which excludes the reactive elements of the system and solely considers real power flow. The DCOPF solution is initially obtained without any DG, followed by the calculation of contribution factors for real power flow on line i-j corresponding to the injection of power at any specific bus k. The lines with the most negative contribution factors are deemed optimal locations for DG placement. Subsequently, after DG placement, the social welfare maximization problem is recalculated.

A probabilistic approach [21] forecasts overloaded transmission lines by strategically placing DG units at congested lines. Furthermore, an optimal planning and scheduling model for Energy Storage Systems (ESSs), incorporating RES, addresses uncertainties from wind-solar units and relieves congestion in the transmission network [22].

2.4.2.4 Electric Vehicles for Congestion mitigation in system

EVs play a crucial role in CM within distributed power markets and distributed networks, introducing both challenges and opportunities. Junjie et al [23] describes one such challenge to distribution system due to unexpected scheduling of EV charging. In their study, an entity known as the Fleet officer (FO) is introduced into the smart grid to coordinate with EV owners and distribution system officers (DSOs). The FO is responsible for documenting the schedule of EV charging within the distribution system, while the DSO verifies the charging schedule provided by the FO by running load flow calculations. These charging schedules provide the DSO with load curves throughout the day, enabling hourly data analysis for the entire duration. Subsequently, the DSO incorporates this data into Load Flow Analysis.

After this FO provides this data to market operator where an OPF is conducted to explore any congestion in the system. If there is any violation of transmission lines, the schedule is rejected, and the FO must reschedule the EV charging load for another time of the day. This process is iterative and converges to a point where the price is minimum, and there is no congestion situation due to EV charging.

The market operator then provides the tariff of EV charging throughout the day, and bids are advertised to the market. EV owners then must either follow the rescheduled charging time or pay an additional price for charging during congested times.

The uncertainties surrounding alternative energy resources in the power system contribute to the complexity of CM. However, the integration of EVs equipped with vehicle-to-grid (V2G) technologies offers a solution for managing network congestion, regulation, and surplus RES storage. Recognized for their environmental and societal benefits, EVs are increasingly regarded as valuable assets in the smart grid. Their integration into the distribution grid enhances charging concepts, reducing congestion levels, and improving voltage conditions [24].

The rising number of electric vehicles in modern electric power systems presents new challenges. Lopez et al. [25] propose that EVs, equipped with V2G technology, can effectively aid power system operators in managing network congestion. In this setup, energy trading occurs through an auction system, allowing agents to trade energy within the system or with neighboring distribution networks. To address congestion issues, a strategy involving V2G technology is proposed.

Power distribution factors (PDFs) are utilized to determine the amount of energy a specific EV should contribute to alleviate congestion in a particular power line. EVs are assumed to have the capability to adjust their battery energy levels, halt charging, or inject energy back into the grid to help maintain system stability.

2.4 Flexibility in power system

The flexibility of a power system refers to its ability to adapt and respond to changes in electricity demand and supply. It involves the capability to adjust generation and consumption patterns, accommodate variations in renewable energy generation, and efficiently manage grid operations [28-29]. Flexibility is crucial for maintaining the stability and reliability of the power system as it encounters dynamic changes. In the context of transmission lines and congestion management, the flexibility of a power system becomes critical for efficiently handling variations in electricity demand and managing congestion issues. Generation Flexibility for Congestion Management may contain Flexible Generation Sources including power plants with the ability to quickly ramp up or down providing flexibility to balance transmission line loads and address congestion. Flexibility is crucial to accommodate the variability of renewable sources, ensuring a smooth integration into the grid without causing congestion. In such case Storage Flexibility for Congestion Relief can be used.

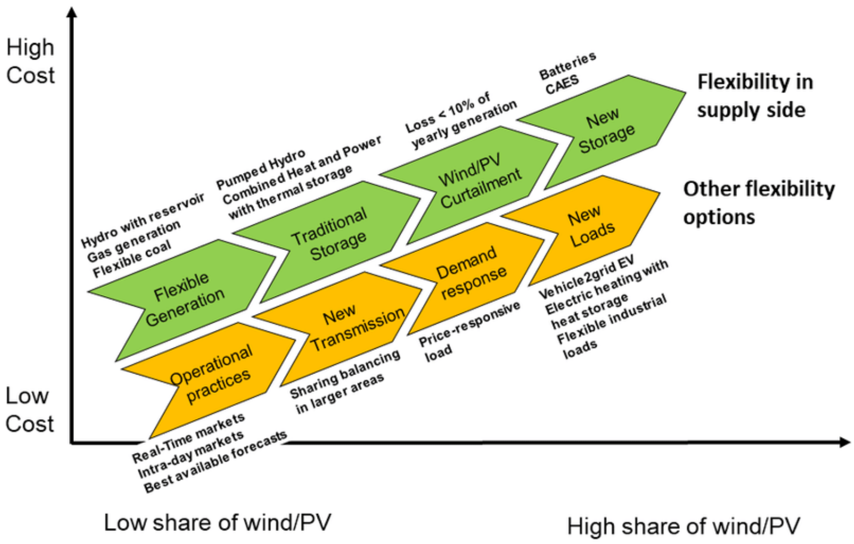

Figure 5 Price of increasing flexibility in power systems [27]

2.4.1 Flexibility Enhancement by Transmission Expansion:

Liang et al [28] propose a method to flexibly expand transmission capacity to accommodate high penetration of wind RES. The study introduces a new approach for addressing uncertainty in wind power generation (WPG). Instead of treating the bounds and uncertainty budget as fixed values, they are treated as variables that can change based on the situation.

This approach determines the best uncertainty budget by considering expected fluctuations in wind power generation. It also takes into account the risks associated with fluctuations that fall outside the uncertainty set. By doing so, it identifies the optimal solution for future transmission planning while ensuring resilience against extreme scenarios. This method strikes a balance between robustness, costs, and computational efficiency, making it more practical for real-world applications compared to standard methods. The study explores different scenarios by simulating uncertainty bounds through various wind probabilistic curves.

2.4.2 Flexibility testing in Bulk Power Systems:

The bulk power system refers to the interconnected network of electrical generation, transmission, and distribution infrastructure that delivers electricity from power plants to end-users across a wide geographic area. It is rather a complex structure to trace any kind of congestion. Ming et al [29] proposed a method to calculate TC indices considering the random failures of power components using the Monte Carlo technique. When multiple components fail simultaneously, it's important to understand each component's contribution to the overall system failure. Two key principles for Transmission Congestion Treatment (TCT) are introduced. Firstly, failed components bear the responsibility for a TC event, while healthy components are not held accountable. Such system is considered, where TC usually occurs when components fail. TC indices are distributed proportionally among the failed components. Based on these principles, a method for sharing responsibility among failed components can be derived, especially suitable for Monte Carlo simulations. This methodology helps in testing the flexibility of the system by analyzing how the system responds to various scenarios of component failures. By considering the random failures of power components using the Monte Carlo technique, the study assesses the system's ability to adapt and maintain stability under different conditions. It helps identify which components are critical for system flexibility and which ones have minimal impact. This understanding is crucial for optimizing system resilience and ensuring that it can handle unforeseen events effectively.

2.5 Verification of a Case Study:

In this section, we verify our methodology by simulating the case study provided in research paper [26], which is the standard IEEE 3-bus system. Furthermore, we will discuss the IEEE 30-bus system used in the methodology of this thesis.

2.5.1 Verification of IEEE 3 bus system

Sreenivasulu [26] provides the methodology of optimal selection of renewable power generation system to be placed in power system to cater congestion. It provides a DC-OPF method to get LMPs at each bus and then explores the feasibility of DG placement in the system to manage congestion. In this study we shall verify the results of research by means of simulation on different software.

2.5.2 DC Optimal Power Flow formulation:

The research work in [26] employs DC Optimal Power Flow (DCOPF) to analyze generation dispatch, load scheduling, LMP, and congestion management. The simple OPF considers constraints from generator and load bids, including network constraints, while DC-OPF does the same but only considers the active components of power. Subroutines are formulated for each design and load profile, maintaining constant unit commitment status. The objective function represents the total operation cost for each scenario.

$$min \sum_{i=1}^{Ngen} C(i, p_g(i)) \tag{2.27}$$

Here, C(i, $p_g(i)$) is the cost for only the real power from generation on the i^{th} unit and N_{gen} is the number of generating units. Usually, we use linear programming to handle control systems but here we are working with the quadratic programming to include the dynamics of the system. The energy cost function is quadratic and here it is defined as follows:

$$C_i(P_{G_i}) = a_i + b_i \times (P_{G_i}) + c_i \times (P_{G_i})^2 \tag{2.28}$$

Here P_{G_i} is the output power generation on the i^{th} generator. “a, b, c” are fuel cost coefficients, where “a” is a constant while “b” and “c” are linear and quadratic product coefficients respectively. Usually during calculations “a” is omitted as it does not have any effect with the change in power generated.

$$\sum_{j=1}^{Nbus} [p_{DR}(j) - p_{dr}(j)] - \sum_{i=1}^{Nbus} [p_g(i)] = 0 \qquad (\gamma \geq 0) \tag{2.29}$$

Here in equation (2.29), N_{bus} represents the number of buses, p_g denotes the generation at a bus, p_d indicates the load at a bus while p_{dr} represents the generation from distributed resources (DR). The symbol γ signifies the constraint limit or the constraint on the system. It could be a physical limitation like a transmission line capacity or a generation capacity constraint [26].

$$\begin{cases} -p_g{}^{max}(i) + p_g(i) \leq 0 & \forall i \\ p_g{}^{min}(i) - p_g(i) \leq 0 & \forall i \\ -p_{dr}{}^{max}(j, ds) + p_{dr}(j) \leq 0 & \forall j \end{cases} \quad 2.30$$

$$LMP_i = \lambda_i + \sum_{j=1}^{N} GSF_{ij} \times \left(PG_j - PD_j\right) \quad 2.31$$

LMP_i is the locational marginal price at node i, λ_i is the base energy price at node i, GSF_{ij} is the generational shift factor between nodes i and j, PG_j is the generation at node j, PD_j is the load (power demand) at node j and N is the total number of nodes in the power system. [26] claims that the system congestion can be reduced using LMP and bidding based DR selection.

$$\begin{cases} p_k = \lambda + \sum_{k_l=1}^{N_{lines}} \mu_{Line_{kl}} \times \frac{\partial P_{kl}}{\partial P} \\ p_k = \lambda + \lambda_{c,k} \end{cases} \quad 2.32$$

The equation (2.32) represents the DC Locational Marginal Price (DC-LMP) model, which accounts for congestion within a power system. In this equation, λ represents the component of marginal energy.

$$\lambda_{c,k} = \sum_{k_l=1}^{N_{lines}} \mu_{Line_{kl}} \times \frac{\partial P_{kl}}{\partial P} \quad 2.33$$

$\lambda_{C,k}$ in equation (2.33) represents the component of congestion i.e. the locational marginal price at node "k" in the presence of congestion "C". The LMP is a measure of the marginal cost of supplying an additional unit of energy at a specific location, $\mu_{Line\text{-}kl}$ represents the Lagrange multiplier associated with the constraint on transmission line "kl". Lagrange multipliers are used in optimization to incorporate constraints into the objective function. In this context, "$Line_{kl}$" represents a transmission line, connecting nodes "k" and "l". Here $\partial P_{kl}/\partial P$ represents the partial derivative of the power flow "P_{kl}" between nodes "k" and "l" with respect to the overall power generation "P". In simpler terms, it measures how the changes in power flow on a specific transmission line effect the overall power generation.

By summing over all the transmission lines in the power system, the equation is considering the cumulative effect of congestion on all the transmission lines. Putting it all together, the equation is essentially stating that the LMP at a specific node ($\lambda_{C,k}$) in the presence of congestion is influenced by the lagrange multipliers associated with transmission line constraints and the impact of changes in power flow on those lines for the overall power generation. The summation captures the cumulative impact of congestion on all transmission lines in the system.

$$\begin{cases} p_l = \lambda + \lambda_{C,l} & \because For\ bus\ l \\ p_k = \lambda + \lambda_{C,k} & \because For\ bus\ k \end{cases} \qquad 2.34$$

The formulation for the LMP at buses 'l' and 'k' is represented by equation (2.34). Here, "λ" provides the normal price, while "$\lambda_{C,l}$" and "$\lambda_{C,k}$" represent the additional price charged because of congestion near buses 'l' and 'k', respectively. This additional price compensates for the damage caused during the operation of congested branches. At each bus, individual spot prices are calculated, and the difference in LMP at the buses connected to a congested branch directly reflect the congestion location. When power forecasts rise at a specific node, both spot prices and congestion flow on the constrained transmission line increase simultaneously. So, difference between LMPs of buses 'k' and 'l' yields

$$\Delta p_{kl} = \left(\lambda_{C,k} - \lambda_{C,l}\right) \qquad 2.35$$

Here in equation (2.35), Δp_{kl} is the spot price calculated by subtracting the LMPs of buses 'l' and 'k'. Given that the marginal energy remains consistent across all nodes in the system, it is excluded from the fluctuation in nodal prices. Consequently, the TCR can be calculated as follows:

$$TCR = \sum_{k_l=1}^{N_{line}} |\Delta p_{kl} P_{kl}| \qquad 2.36$$

Here in equation (2.36) TCR represents the total congestion rent, and Δp_{kl} denotes the calculated spot price, while P_{kl} represents the line power flow from 'k' to 'l'. Typically, it is not sensible to install DG at buses where the power generation exceeds the demand because the LMPs are already low. To simplify the calculation process, we will initially assess the buses using the condition presented in equation (2.37). The most suitable location for implementing DG is at a bus where the power generation is lower than the load.

$$P_g(j) \leq P_d(j) \qquad j = 1 \dots N_{bus} \qquad 2.37$$

Equation (2.37) represents the condition where DG placement is applicable. $P_g(j)$ represents the power generated at bus j, while $P_d(j)$ represents the power demand at bus j, where the value of j ranges from 1 to the number of buses. In summary, the equation indicates that it is never optimal to place a DG on any bus where the generation is already greater than the load. The placement of DG is only applicable on buses with power demand higher than the power generation at that bus.

The method described for determining the placement of DRs can be applied to all designs, allowing the calculation of benefits for each point in the system. Subsequently, based on the cost of each design, we can determine the Benefit Cost Ratio (BCR). The design with the highest BCR is considered the optimal solution since it ensures the highest benefit on a fixed cost.

In [26] we are also provided with an algorithm that outlines the complete process of optimization. The steps of the algorithm are provided as follows:

1. Start.
2. Import the input data from the excel file for load data, generator data and branch data.
3. Run DC-OPF.
4. From the results extract only those buses which have the highest LMP.
5. Enter the system parameters for time and locations i.e. all years and buses.
6. Calculate DRs cost for all planned designs.
7. Provide Unit Commitment Parameters (UCPs) and run the OPF again for all load intervals.
8. Calculate DRs benefit for all intervals along with the BCR for DRs for each design at each year.
9. Extract the data for optimal sizing and location of DR.
10. Stop.

2.5.3 Simulation on ETAP

For this system, simulations are conducted using the ETAP software, where a DC Optimal Power Flow (DC-OPF) is executed, considering only real power. The study focuses on a three-bus system and proposes the addition of DG units to alleviate congestion. We implemented DC-OPF because the paper we are implementing considered only resistive load. The simulations are performed for the three-bus system as described in the reference paper [26], and the following results are observed which are mentioned in the sections below.

2.5.3.1 Simulation without DG (ETAP)

The simulation involves IEEE 3 bus system, and the relevant generation and line data for the system is provided in Table 1 and Table 2 and respectively. Initially, the system is executed without any DG. This allows us to identify any congested areas within the system and assess its performance under normal operating conditions.

Table 1: Generation data for each bus

Bus No	Generation (MW)	A(Rs./MW^2)h	B(Rs./MWh)	C(Rs.)
1	100	4.8	2334	3360
3	100	0.6	660	8700

Table 2: Line data for each line

Line No	From Bus	To Bus	Reactance (X) pu	Amperage Rating (A)
1	1	2	0.20	430
2	1	3	0.40	525
3	2	3	0.25	365

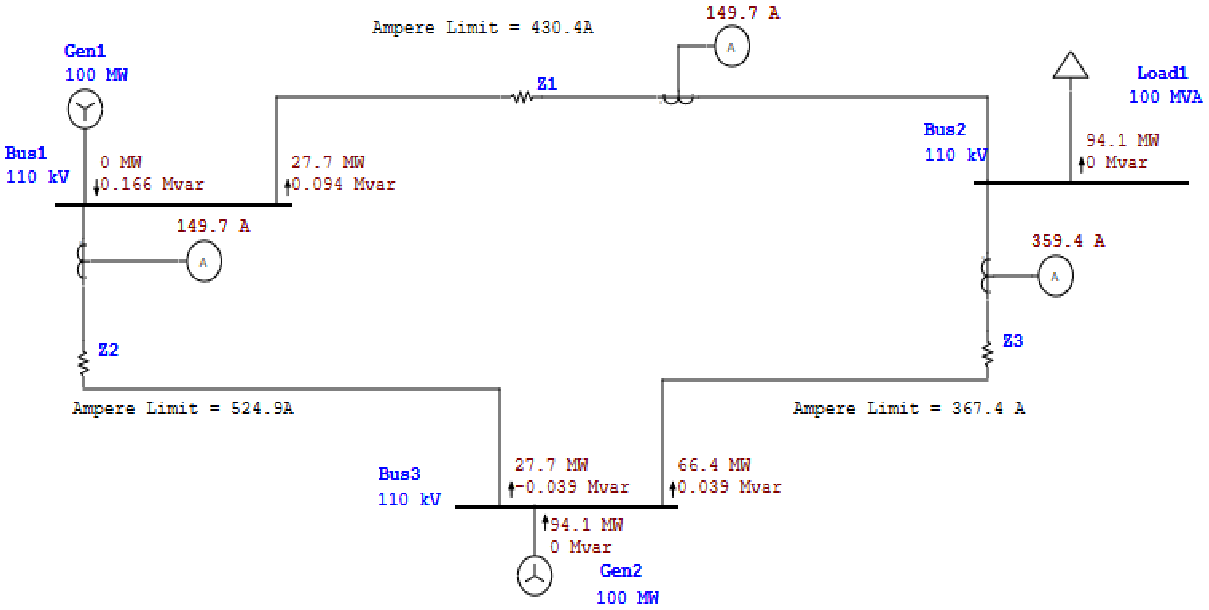

Figure 6: ETAP simulation for 3 bus system without DG

From the simulation in Figure 6, we can observe that line 3, between bus 2 and bus 3, is facing congestion as it is operating at 97.8% of its ampere limit, with a current flow of 359.4A compared to its limit of 367.4A. This indicates a loss of flexibility, and any additional load could potentially cause physical damage. Table 3 provides the load status of each branch.

Table 3: ETAP IEEE 3 bus Simulation without DG

Branch no	From Bus	To Bus	Amperes Limit	Ammeter reading	% MW Load
1	1	2	430.4	149.7	34.7
2	1	3	524.9	149.7	28.5
3	2	3	367.4	359.4	97.8

2.5.3.2 Simulation of Scheme 1 (ETAP)

In Scheme 1, shown in Figure 7 a solar-powered renewable energy source is introduced to the system. This addition includes an inverter and a transformer installed at the bus near the congested transmission line. The solar power generation capacity is 20MW. The generated AC power, initially at 0.11kV at frequency 50 Hz, is fed to the transformer. The transformer steps up the voltage to 110kV with a ratio of 100:1.

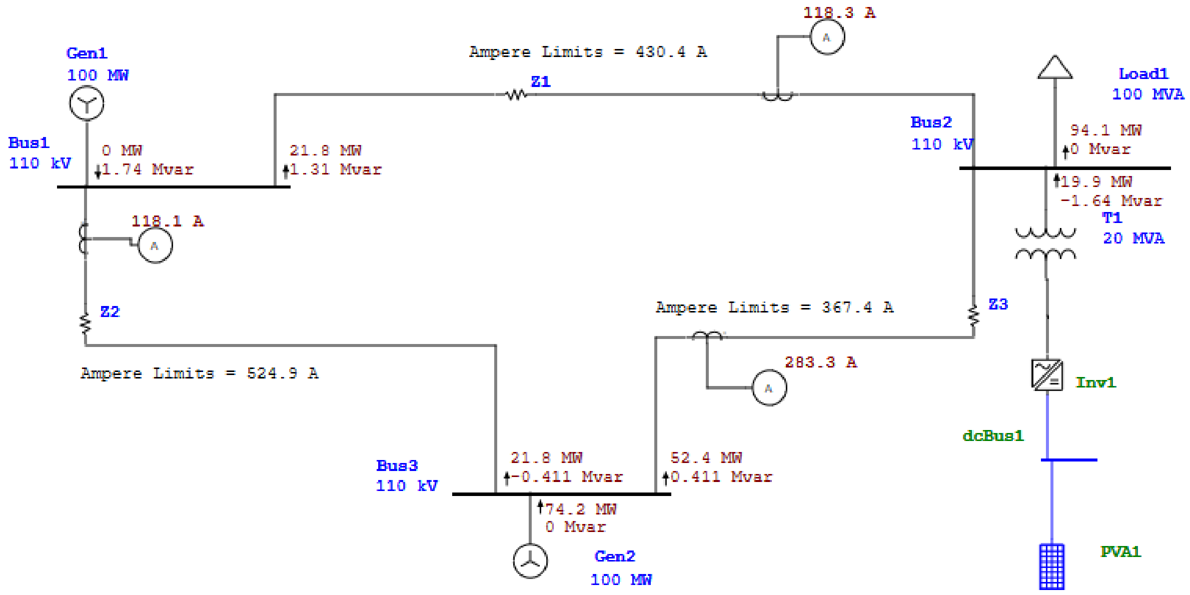

Figure 7: ETAP simulation for Scheme 1

From Figure 7, we can notice that the addition of solar RES has successfully eliminated congestion, reducing the flow of current in line 3 from 359.4A to 283.3A. As a result, the loading of this branch has decreased to 77% of its full load MVA limit. The system now exhibits increased flexibility to accommodate additional load on any of the buses. The ampere rating for each branch of Scheme 1 is depicted in Table 4.

Table 4: ETAP simulation for Scheme 1

Branch no	From Bus	To Bus	Amperes Limit	Ammeter reading	%MW Load
1	1	2	430.4	118.2	27.4
2	1	3	524.9	118.1	22.5
3	2	3	367.4	283.3	77.1

2.5.3.3 Simulation of Scheme 2 (ETAP)

In the Scheme 2, which is depicted in Figure 8 Wind-powered renewable energy source is added to the bus near the congested transmission line. The Wind RES has a generation capacity of

20MW. For the simulation, we are assuming no wind constraint to ensure a steady simulation. The Wind RES acts as an additional generator to facilitate the simulation process.

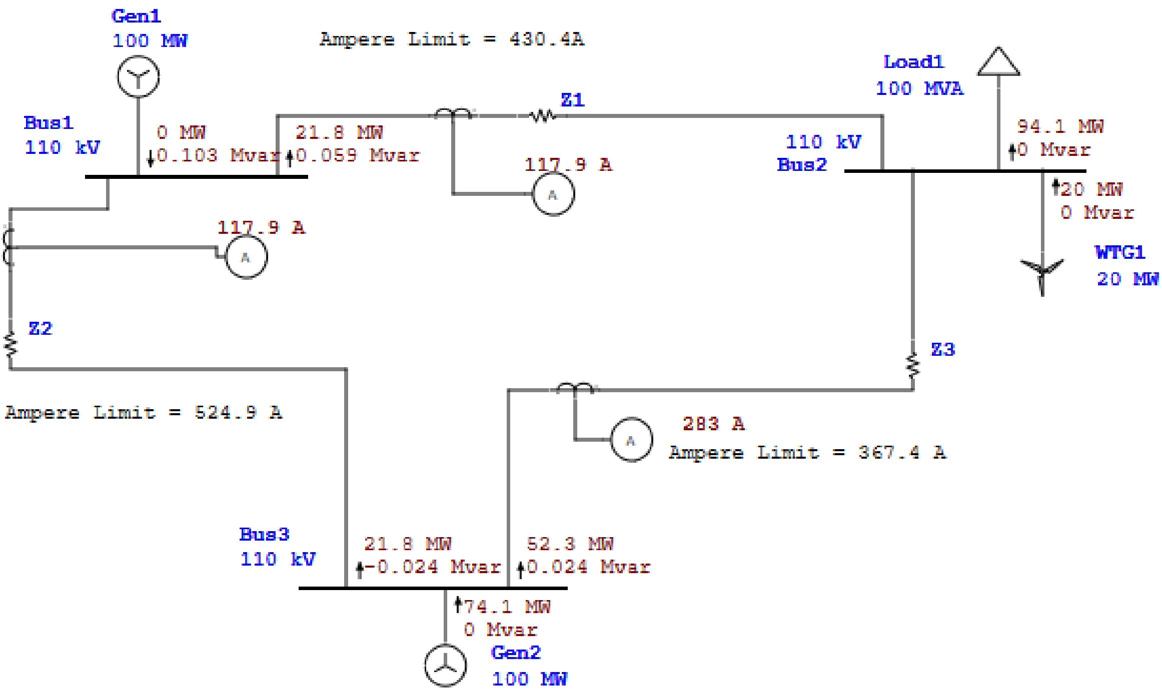

Figure 8: ETAP simulation for Scheme 2

Scheme 2, as indicated by the data presented in Table 5, has also effectively alleviated congestion using a similar approach. The Wind RES has successfully eliminated congestion, reducing the current in line 3 from 359.4A to 283A. As a result, the branch's loading has decreased to 77% of its maximum MVA capacity, providing the system with increased flexibility to accommodate additional load on any of the buses. This scheme is particularly suitable for regions with consistent wind resources.

Table 5: ETAP simulation for Scheme 1

Branch no	From Bus	To Bus	Amperes Limit	Ammeter reading	%MW Load
1	1	2	430.4	117.9	27.3
2	1	3	524.9	117.9	22.4
3	2	3	367.4	283	77

2.5.3.4 Simulation of Scheme 3 (ETAP)

In Scheme 3, as illustrated in Figure 9, we implemented both Solar and Wind-powered renewable energy sources at the bus near the congested transmission line. This integrated solution harnesses the benefits of both solar and wind energy to effectively alleviate congestion and enhance the reliability of the power system.

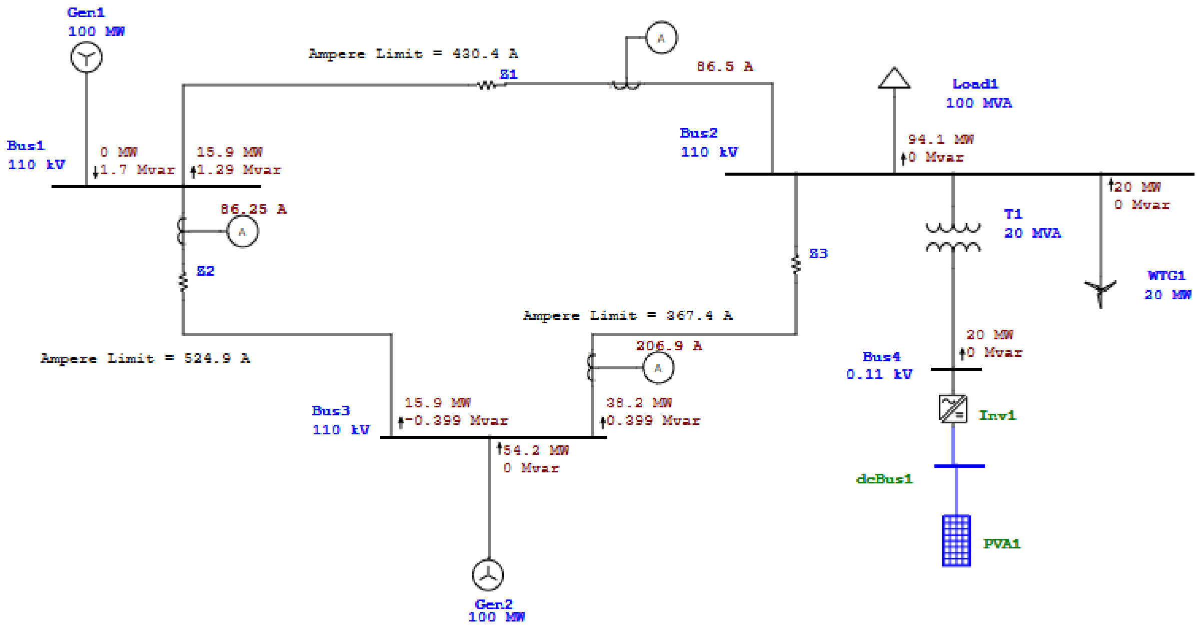

Figure 9: ETAP simulation of scheme 3

Scheme 3, as shown by the data in Table 6, has tremendously contributed to the removal of congestion. The amperage has dropped to 56.2% of the total rating, with a current reading of 206.7A. This substantial reduction in current signifies a significant increase in the system's flexibility and resilience.

Table 6: ETAP Simulation of Scheme 3

Branch no	From Bus	To Bus	Amperes Limit	Ammeter reading	%MW Load
1	1	2	430.4	86.5	20
2	1	3	524.9	86.25	16.4
3	2	3	367.4	206.7	56.2

During the simulations, a constraint was encountered that ETAP was unable to calculate the LMPs at each bus. Since ETAP is primarily designed for load flow and fault analysis, we needed an alternative solution. To address this issue, we opted to use Power World Simulator (PWS), another software capable of calculating LMPs at each bus.

2.5.4 Simulation on Power World Simulator

A similar IEEE 3-bus system was implemented on PWS, which is a software specifically designed for load flow and OPF studies in power systems. However, PWS only supports AC sources, lacking compatibility with DC sources. To incorporate DGs into the system for OPF analysis, we had to represent them as AC sources. For example, we utilized an AC source to simulate the presence of a solar RES, including its inverter and respective transformer. With the system set up, we proceeded with the OPF study to calculate the LMPs on each bus.

2.5.4.1 Simulation without DG

The system is constructed in PWS, and OPF is conducted to analyze LMPs at each bus. The study focuses on a three-bus system, with plans to integrate DGs to mitigate congestion. Initial steps involve system construction and OPF simulation. The Table 7 represents the real and reactive power of generators and loads at different buses. Whereas, Table 8 shows the current and power flow in the transmission lines.

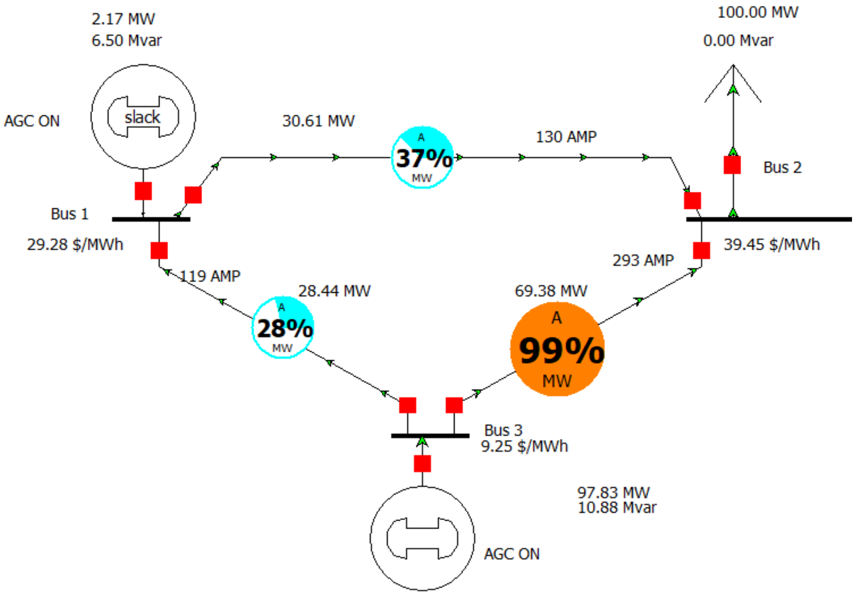

Figure 10: OPF of system without DG

Table 7: Results of OPF without DG

Bus no	P_g (MW)	P_d (MW)	Q_g (Mvar)	Q_d (Mvar)	LMP ($/MWh)	LMP (RS/MWh)
1	2.17	0	6.5	0	29.28	2430.67
2	0	100	0	0	39.45	3274.93
3	97.3	0	10.88	0	9.25	767.89

Table 8: Results of OPF for lines without DG

Line No	Real power flow P_f (MW)	Current flow I_f (AMPs)	% MW Load
1	30.61	130	37
2	28.44	119	28
3	69.38	293	99

From the simulation in Figure 10, we can observe severe congestion on line 3, which connects bus 2 and bus 3. Additionally, the calculated LMPs confirm congestion on this line, as it is operating at 99% of its capacity. Comparing the calculated LMPs reveals that bus 2 has the highest LMP among all the buses. Following the methodology outlined in the study [26], bus 2 emerges as a suitable location for DG placement. Consequently, the study presents three designs, which will be discussed here.

2.5.4.2 Design 1 Addition of Solar Powered DG:

The initial design suggests implementing a DG, comprising of solar-powered RES with a capacity of 20MW, as shown in Figure 11. The energy tariff for this DG is set at 4.63 Rs/KWh, equivalent to 56$/MWh at the congested line and the bus with the highest LMP, which is bus 2. The power generated and consumed along with the LMPs are demonstrated in Table 9 and Table 10 shows the OPF results.

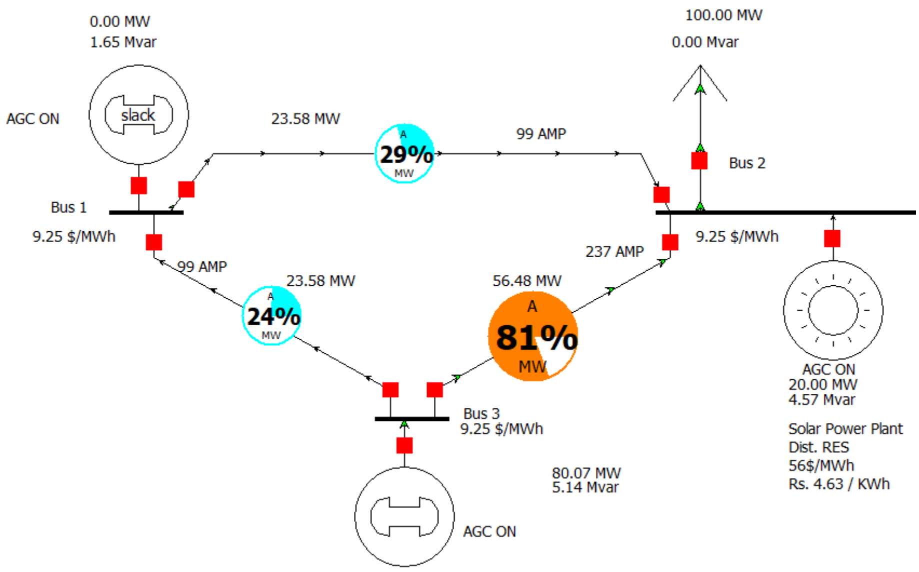

Figure 11: DC-OPF result with design 1 Solar RES

Table 9: Results of OPF with design 1

Bus no	P_g (MW)	P_d (MW)	Q_g (Mvar)	Q_d (Mvar)	LMP ($/MWh)	LMP (RS/MWh)
1	0	0	1.65	0	9.25	769.81
2	0	100	4.57 (DG)	0	9.25	769.81
3	80.07	0	5.14	0	9.25	769.81

Table 10: Results of OPF for lines with design 1

Line No	Real power flow P_f (MW)	Current flow I_f (AMPs)	% MW Load
1	23.58	99	29
2	23.58	99	24
3	56.48	237	81

We can observe from the line data in Table 10 that line 3, connecting bus 2 and 3, is now less congested as it is operating at 81% of its capacity. Also, we can observe from Table 9 that LMPs for all the buses are now equal after the removal of congestion.

2.5.4.3 Design 2 Addition of Wind Powered DG:

The second design proposed is a DG, consisting of Wind power RES with a capacity of 20MW, priced at 5 Rs/KWh or 60$/MWh, situated at the congested line and the bus with the highest LMP, i.e., bus 2, as demonstrated in Figure 12.

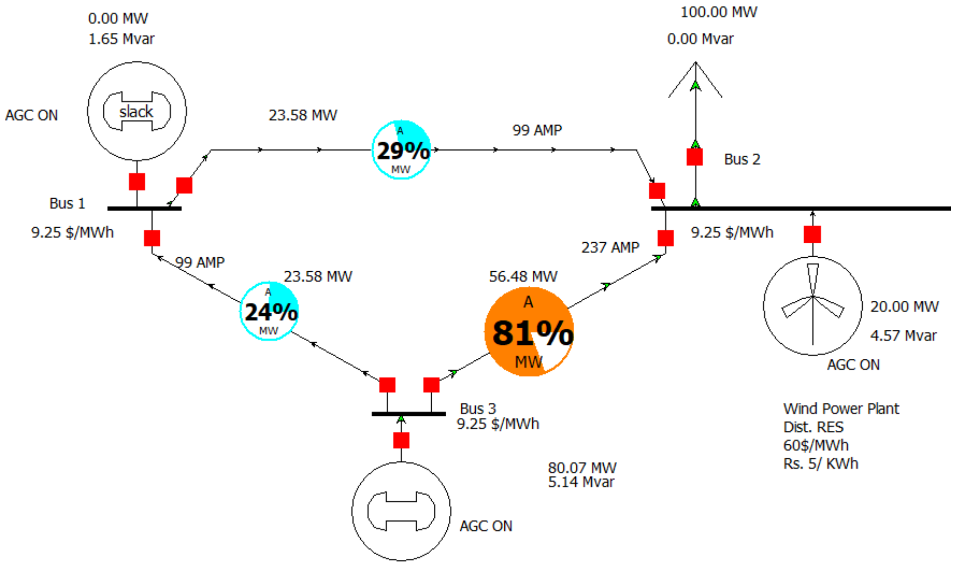

Figure 12: DC-OPF result with design 2 wind RES

Table 11: Results of OPF with design 2

Bus no	P_g (MW)	P_d (MW)	Q_g (Mvar)	Q_d (Mvar)	LMP ($/MWh)	LMP (RS/MWh)
1	0	0	1.65	0	9.25	769.81
2	0	100	4.57 (DG)	0	9.25	769.81
3	80.07	0	5.14	0	9.25	769.81

Table 12: Results of OPF for lines with design 1

Line No	Real power flow P_f (MW)	Current flow I_f (AMPs)	% MW Load
1	23.58	99	29
2	23.58	99	24
3	56.48	237	81

By comparing the calculated LMPs in Table 11, we notice that all buses now have equivalent LMPs, and the results observed are same as in design 1, just like the study in [26] observed.

2.5.4.4 Design 3 Addition of both DGs:

The third design proposed is a Hybrid DG, consisting of both Renewable Energy Sources (RES) of 20MW each. This model shown in Figure 13 shall bring down the overall equivalent LMPs and should enhance the capacity of transmission lines.

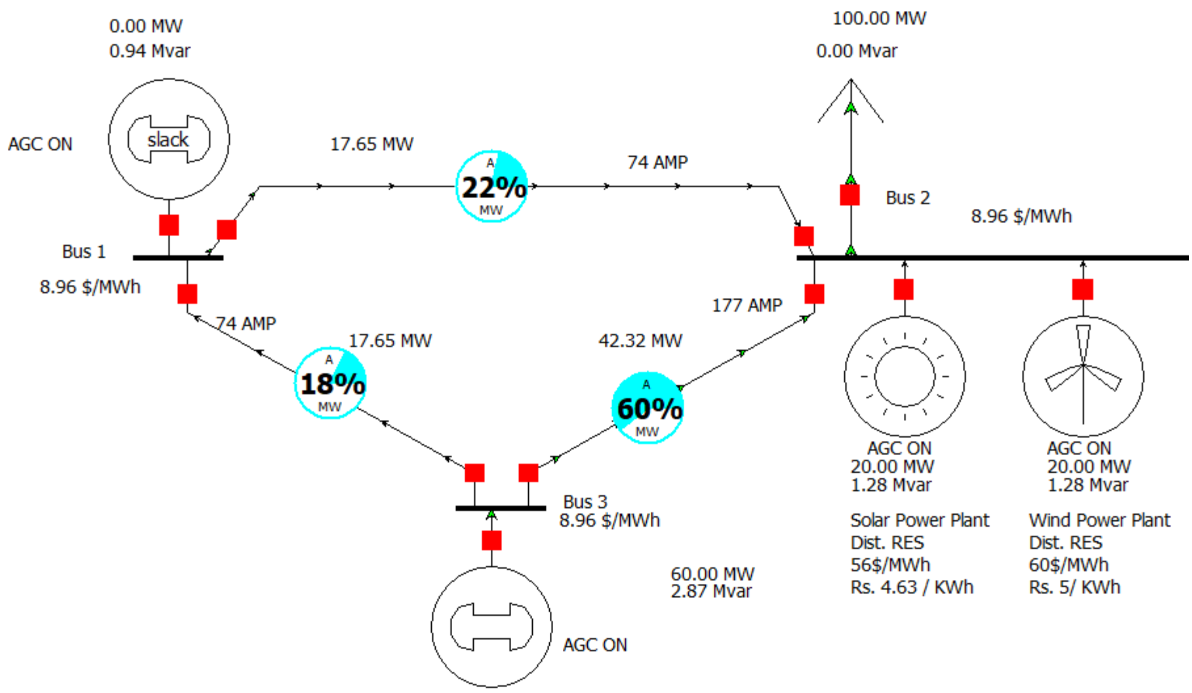

Figure 13: DC-OPF result with design 3 both RES

Table 13: Results of OPF with design 3

Bus no	P_g (MW)	P_d (MW)	Q_g (Mvar)	Q_d (Mvar)	LMP ($/MWh)	LMP (RS/MWh)
1	0	0	0.94	0	8.96	743.81
2	0	100.00	1.28*2	0	8.96	743.81
3	60.00	0	2.87	0	8.96	743.81

Table 14: Results of OPF for lines with design 3

Line No	Real power flow P_f (MW)	Current flow I_f (AMPs)	% MW Load
1	17.65	74	22
2	17.65	74	18
3	42.32	177	60

All three designs are removing the congestion and equating the LMP prices, as shown in Table 13. However, from the results obtained in Table 14, we can observe that hybrid model of design 3 provides the greatest flexibility in the system as line 3 is now operating at only 60% of its capacity and also the LMP prices are lowest in this design which verifies the case implemented in the paper [26].

2.5.5 Assessing the Benefits of Distributed Resources (DRs):

Evaluating the Benefits of distributed resources involves considering economic factors like Upgrade Investment Deferral (UID), Power Purchase Savings (PPS), and the Reduction in Total Congestion Rent (TCRR). These three elements are quantified to analyze the advantages of utilizing distributed resources (DRs) at locations with the highest LMPs [26].

In periods of peak demand, power generation will be strategically located near high-demand areas, leading to decreased power flow and a potential need for upgrading overloaded feeders. The value of this benefit in the context of DRs depends on the system's cost structure, feeder specifications, the placement of the DR, and the rate of demand growth. Such upgrade investment is quantified by UID. PPS represents the savings resulting from a decrease in the amount of electricity bought from the power market to supply customers. This reduction in purchased power contributes to cost savings.

$$PPS = \sum_{t=1}^{N_{year}} \sum_{k=1}^{N_{DG}} \sum_{m=1}^{N_c} \delta_m \times P_{k_t}^{DR} \times MCP_t^m \tag{2.38}$$

Here $P_{k_t}^{DR}$is output power of k^th^ DR at t^th^ year and MCP_t^m is the market clearing price of m^th^ case at t^th^ year. Similarly, total congestion rent reduction is the metric that signifies the decrease in congestion-related costs within the system attributed to the utilization of DRs. It can be calculated in the following manner:

$$TCRR = \sum_{t=1}^{N_{years}} \sum_{m=1}^{N_c} TCR_{m,t}^{ini} - TCR_{m,t}^{DR} \tag{2.39}$$

Here $TCR_{m,t}^{ini}$ is TCR for m^th^ case without DR and $TCR_{m,t}^{DR}$ is TCR for m^th^ case without DR.

2.5.6 Verification on IEEE 30 bus system

From this point on, we will apply the same method to a larger system consisting of 30 buses. For this purpose, we have selected the standard IEEE 30-bus system. During our analysis, we will apply different contingencies to the system to impose extra burden on the branches. By doing so, we will be able to induce congestion in the system branches, and then we will attempt to mitigate this congestion using the same methodology. Figure 14 shows the single-line diagram of the IEEE 30-bus system used for the study in this thesis.

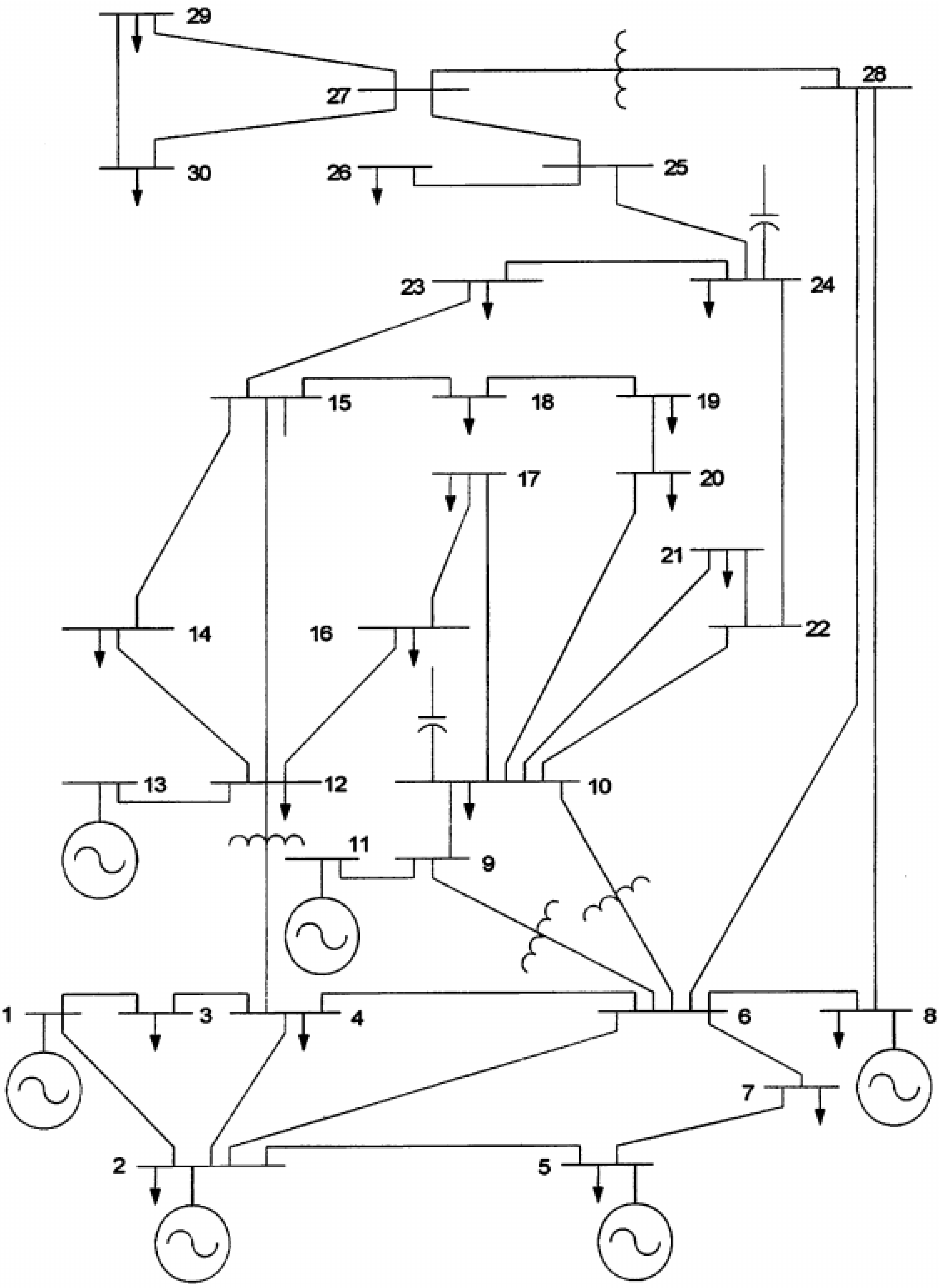

Figure 14 Single line diagram for IEEE 30 bus system [30]

3 Methodology

For the methodology used in this thesis, we implemented the IEEE 30-bus system as a case study to apply our algorithm. The steps of our methodology are as follows:

1. **Building Simulation Model:** First, we built the simulation environment in the PWS to observe the effects of modifications in the system. Once the environment was built, we started observing the system's flexibility by conducting contingency analysis.
2. **Data collection:** By introducing contingencies at each branch one by one, we can generate the data required to begin the research. To collect data, we introduce a fault on a branch, then run the OPF and calculate the LMPs on each bus in the presence of that fault. Some of the buses will appear critical, as faults initiated on these buses will create higher congestion within the system.
3. **Optimality of FACTs Devices for compensation:** We observe the congested lines to see if there is high reactive power flowing through the branch that can be locally compensated using FACTS devices. If such a provision exists, the congestion can be alleviated by employing FACTS devices.
4. **Optimal Placement of DG:** Once we have the data from all the contingencies in the system, it will be evident which buses consistently experience elevated LMPs. These buses will be the optimal locations for our DG placement.
5. **Reiteration:** After placing the DG at its optimal location, we will perform another OPF on the system to observe the effects of DG placement on the power system. If congestion is eliminated at all branches, we will proceed to apply contingencies to the next branch of the system. Otherwise, we will analyze the LMPs data and identify the bus with the second most frequently elevated LMP during the contingencies. This bus will be the optimal location to place the second DG to alleviate congestion. We will continue this process until congestion is alleviated during each contingency.
6. **Introduction of Control Strategy using Relays:** A battery backup system is also introduced along with DGs to further enhance the flexibility of the system. Each branch is monitored by overcurrent relays that generate trip signals upon sensing congestion in the line. These trip signals will initiate the introduction of backup systems near the congested area.

4 Simulations of methods

We simulated the standard unmodified IEEE-30 bus system on PWS. For the OPF, we need the cost of generation for each plant. This is usually provided in the form of a standard cubic cost equation, as described in equations (2.8) and (2.28) in the previous sections. In Table 15, only the coefficients of the cost function 'a', 'b', and 'c' are given. Table 16 gives the load and generation data used from a standard IEEE 30-Bus system.

Table 15: Cost Data IEEE-30 bus

Name	P_{min} (MW)	P_{max} (MW)	Q_{min} (MVAR)	Q_{max} (MVAR)	A ($/$MW^2$)h	B ($/MWh)	C ($)
Gen 1	50	200	.	.	0.00375	2	0
Gen 2	20	80	-20	100	0.0175	1.75	0
Gen 5	15	50	-15	80	0.0625	1	0
Gen 8	10	35	-15	60	0.00834	3.25	0
Gen 11	10	30	-10	50	0.025	3	0
Gen 13	12	40	-15	60	0.025	3	0

Table 16: Load/Generation data IEEE-30 bus

Name	Load MW	Load MVAR	Gen MW	Gen MVAR
Bus 1	0	0	197.51	-40.84
Bus 2	21.7	12.7	44	25.48
Bus 3	2.4	1.2	0	0
Bus 4	67.6	1.6	0	0
Bus 5	34.2	1.9	22	10.71
Bus 6	0	0	0	0
Bus 7	22.8	10	0	0
Bus 8	30	30	10	36.94
Bus 9	0	0	0	0
Bus 10	5.8	2	0	0
Bus 11	0	0	10	6.58
Bus 12	11.2	7	0	0
Bus 13	0	0	12	8.17
Bus 14	6.2	1.6	0	0
Bus 15	8.2	2	0	0
Bus 16	3.5	1.8	0	0
Bus 17	9	5.8	0	0
Bus 18	3.2	0.9	0	0
Bus 19	9.5	3.4	0	0
Bus 20	2.2	0.7	0	0
Bus 21	17.5	1.1	0	0
Bus 22	0	0	0	0
Bus 23	3.2	1.6	0	0

Bus 24	8.7	0.7	0	0
Bus 25	0	0	0	0
Bus 26	3.5	2	0	0
Bus 27	0	0	0	0
Bus 28	0	0	0	0
Bus 29	2.4	0.6	0	0
Bus 30	10.6	1	0	0

Additionally, for the OPF, we require the MVA limits of branches to apply the constraints. To fulfill this requirement, we have obtained the standard IEEE-30 bus branch data, comprising of 41 branches, with detailed information provided in the table 17.

Table 17: Branch Data IEEE-30 bus

Branch no	From Name	To Name	Branch Device Type	R	X	Lim MVA
1	Bus 1	Bus 2	Line	0.0192	0.0575	130
2	Bus 1	Bus 3	Line	0.0452	0.1852	130
3	Bus 2	Bus 4	Line	0.057	0.1737	65
4	Bus 2	Bus 5	Line	0.0472	0.1983	130
5	Bus 6	Bus 2	Line	0.058	0.1763	65
6	Bus 3	Bus 4	Line	0.0132	0.0379	130
7	Bus 6	Bus 4	Line	0.0119	0.0414	90
8	Bus 4	Bus 12	Transformer	0	0.256	65
9	Bus 7	Bus 5	Line	0.046	0.116	70
10	Bus 6	Bus 7	Line	0.0267	0.082	130
11	Bus 6	Bus 8	Line	0.012	0.042	32
12	Bus 6	Bus 9	Transformer	0	0.208	65
13	Bus 6	Bus 10	Transformer	0	0.556	32
14	Bus 6	Bus 28	Line	0.0169	0.599	32
15	Bus 8	Bus 28	Line	0.0636	0.2	32
16	Bus 9	Bus 10	Line	0	0.11	65
17	Bus 9	Bus 11	Line	0	0.208	65
18	Bus 10	Bus 17	Line	0.0324	0.0845	32
19	Bus 10	Bus 20	Line	0.0936	0.209	32
20	Bus 10	Bus 21	Line	0.0348	0.0749	32
21	Bus 10	Bus 22	Line	0.0727	0.1499	32
22	Bus 13	Bus 12	Line	0	0.14	65
23	Bus 12	Bus 14	Line	0.123	0.2559	32
24	Bus 12	Bus 15	Line	0.0662	0.1304	32
25	Bus 12	Bus 16	Line	0.0945	0.1987	32
26	Bus 14	Bus 15	Line	0.0221	0.1997	16
27	Bus 15	Bus 18	Line	0.107	0.2185	16
28	Bus 15	Bus 23	Line	0.1	0.202	16
29	Bus 17	Bus 16	Line	0.0824	0.1932	16
30	Bus 18	Bus 19	Line	0.0639	0.1292	16

31	Bus 19	Bus 20	Line	0.034	0.068	32
32	Bus 21	Bus 22	Line	0.0116	0.0236	32
33	Bus 22	Bus 24	Line	0.115	0.179	16
34	Bus 24	Bus 23	Line	0.132	0.27	16
35	Bus 24	Bus 25	Line	0.1885	0.3292	16
36	Bus 25	Bus 26	Line	0.2544	0.38	16
37	Bus 25	Bus 27	Line	0.1093	0.2087	16
38	Bus 27	Bus 28	Transformer	0	0.369	65
39	Bus 27	Bus 29	Line	0.2198	0.4153	16
40	Bus 27	Bus 30	Line	0.3202	0.6027	16
41	Bus 29	Bus 30	Line	0.2399	0.4533	16

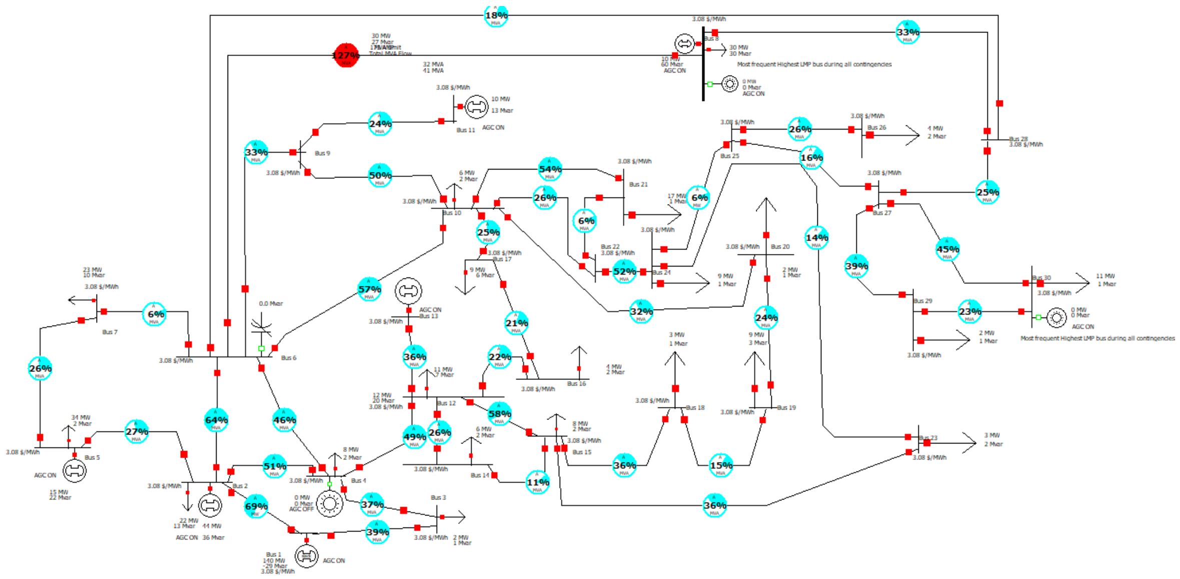

Figure 15: OPF of Unmodified IEEE 30 bus system

After conducting the OPF analysis of the standard IEEE-30 bus system, we observe from Figure 15 that the system exhibits congestion at branch 11. Also, the percentages at which the branches are operating suggest that the system lacks flexibility. Operating near 95% of their MVA limit, branches indicate potential vulnerability to congestion in the event of a fault. This highlights the importance of addressing operational constraints to ensure system reliability and stability.

4.1 Contingency Analysis of IEEE 30 bus system

Contingency analysis is a method employed in power system management to evaluate how potential equipment failures or unexpected events might affect the reliability and security of the electrical grid. For evaluation of the flexibility of the system contingency analysis observes how well a power system can handle equipment failures or unexpected events. It assesses if the system can adapt to changes without losing reliability or security.

One of the key components of contingency analysis involves analyzing the total power flow through individual branches and calculating the percentage of the MVA (megavolt-ampere) limit at which each branch operates. This measure, often referred to as the MVA loading percentage, indicates the extent to which a branch is approaching or exceeding its capacity. By systematically simulating faults on each branch and compiling the results, contingency analysis identifies potential congestion points where the MVA limit may be violated. This information enables grid operators to proactively address vulnerabilities and enhance the overall resilience of the power system. Table 18 shows the congestion in transmission lines by introducing contingency at each branch.

Table 18: MVA Limit violation on branches for each contingency

Contingency Branch	From Name	To Name	Branch Device Type	MVA Limit violation
1	Bus 1	Bus 2	Line	2, 11
2	Bus 1	Bus 3	Line	1, 11
3	Bus 2	Bus 4	Line	11
4	Bus 2	Bus 5	Line	11
5	Bus 6	Bus 2	Line	1, 11
6	Bus 3	Bus 4	Line	1,3
7	Bus 6	Bus 4	Line	5,11
8	Bus 4	Bus 12	Transformer	11
9	Bus 7	Bus 5	Line	11
10	Bus 6	Bus 7	Line	11
11	Bus 6	Bus 8	Line	*
12	Bus 6	Bus 9	Transformer	11
13	Bus 6	Bus 10	Transformer	11
14	Bus 6	Bus 28	Line	11
15	Bus 8	Bus 28	Line	11
16	Bus 9	Bus 10	Line	11, 13
17	Bus 9	Bus 11	Line	11
18	Bus 10	Bus 17	Line	11
19	Bus 10	Bus 20	Line	11, 27
20	Bus 10	Bus 21	Line	11
21	Bus 10	Bus 22	Line	11
22	Bus 13	Bus 12	Line	11
23	Bus 12	Bus 14	Line	11
24	Bus 12	Bus 15	Line	11
25	Bus 12	Bus 16	Line	11
26	Bus 14	Bus 15	Line	11
27	Bus 15	Bus 18	Line	11
28	Bus 15	Bus 23	Line	11
29	Bus 17	Bus 16	Line	11
30	Bus 18	Bus 19	Line	11

31	Bus 19	Bus 20	Line	11
32	Bus 21	Bus 22	Line	11
33	Bus 22	Bus 24	Line	11
34	Bus 24	Bus 23	Line	11
35	Bus 24	Bus 25	Line	11
36	Bus 25	Bus 26	Line	11
37	Bus 25	Bus 27	Line	11
38	Bus 27	Bus 28	Transformer	11, 33,35
39	Bus 27	Bus 29	Line	11
40	Bus 27	Bus 30	Line	11
41	Bus 29	Bus 30	Line	11

The detailed data for all 41 contingencies of each branch is provided in Appendix A. We have collected data for each contingency and their relative LMPs on each bus. The detailed data of LMPs on all buses for 41 contingencies is provided in Appendix B.

4.1.1 Criterion for branch sensitivity

The criterion used for measuring sensitivity, in this case, is the observation of the number of branches affected by the failure of a power system component. During the contingency analysis, the effects of component failure are studied. Therefore, the most sensitive branch of the system will affect the highest number of branches during a fault condition.

Analysis reveals that the most critical contingency observed belonged to branch 38, linking bus 27 and 28. This contingency is anticipated to induce congestion on other branches (11, 33, and 35). Therefore, it will serve as the starting point for our simulation. In our simulation, we will simulate the failure of branch 38 and then calculate the OPF. We can observe the simulated results in Figure 16.

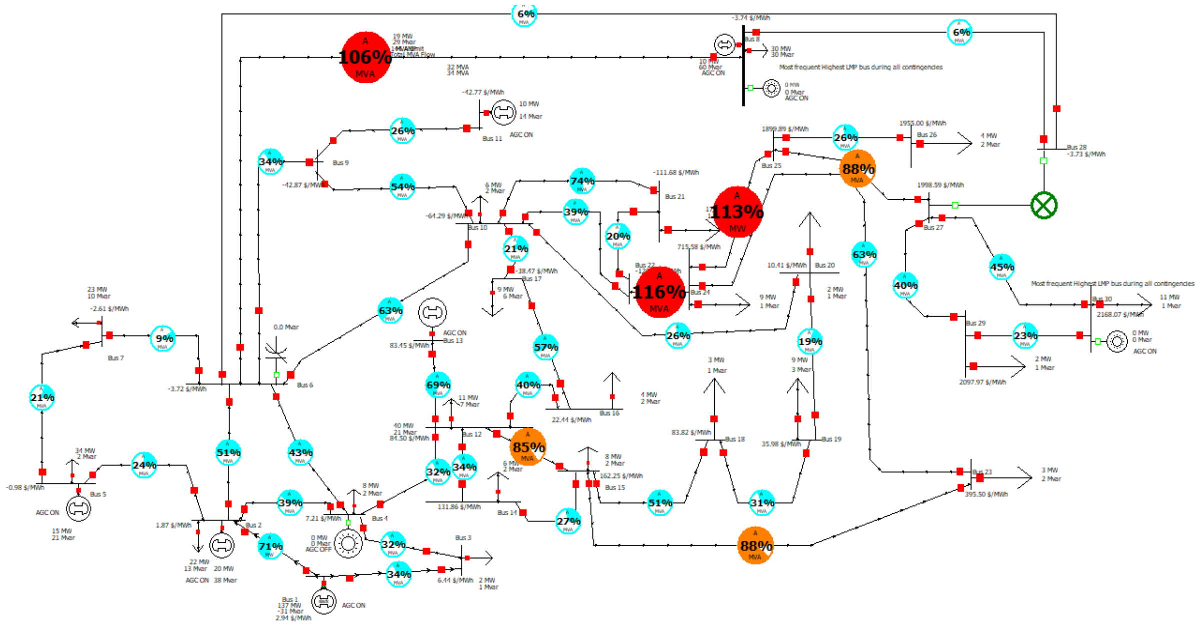

Figure 16: Contingency at branch 38 inducing congestion at multiple buses

According to Table 19, during the most critical contingency, the highest LMP throughout the system reaches as high as $2168.07, observed on bus 30. Therefore, we have identified bus 30 as the target location for installing a DG unit. A solar-powered DG with a capacity of 20 MW of real power and 20 Mvar of reactive power is placed, with an average operational cost of $2.5/MWh.

Table 19: LMPs of buses for Contingency on Branch 38

Bus Number	MW Marg. Cost	Bus Number	MW Marg. Cost
1	2.94	16	22.44
2	1.87	17	-38.47
3	6.44	18	83.82
4	7.21	19	35.98
5	-0.98	20	10.41
6	-3.72	21	-111.68
7	-2.61	22	-126.4
8	-3.74	23	395.5
9	-42.87	24	715.58
10	-64.29	25	1899.89
11	-42.77	26	1955
12	84.5	27	1998.59
13	83.45	28	-3.73
14	131.86	29	2097.97
15	162.25	30	2168.07
Highest LMP Bus		30	
Highest LMP		2168.07	

After implementing this DG, the OPF is conducted again as shown in Figure 17. The results indicate that the congestion is removed and the LMPs for all the buses converge to the same value. This indicates that the system is not violating any power flow constraints. Table 20 shows LMPs of each bus after the placement of DG during contingency 38.

Table 20: LMPs of each bus after placement of DG (under contingency 38)

Bus Number	MW Marg. Cost	Bus Number	MW Marg. Cost
1	2.94	16	2.94
2	2.94	17	2.94
3	2.94	18	2.94
4	2.94	19	2.94
5	2.94	20	2.94
6	2.94	21	2.94
7	2.94	22	2.94
8	2.94	23	2.94
9	2.94	24	2.94
10	2.94	25	2.94
11	2.94	26	2.94
12	2.94	27	2.94
13	2.94	28	2.94
14	2.94	29	2.94
15	2.94	30	2.94

Table 21: % of MVA limit for each branch before and after DG placement on bus 30 (under contingency 38)

Branch no	From Name	To Name	% of MVA Limit (Before)	% of MVA Limit (After)
1	Bus 1	Bus 2	74.3	68.4
2	Bus 1	Bus 3	34.5	34.8
3	Bus 2	Bus 4	38.5	42.8
4	Bus 2	Bus 5	23.9	24.4
5	Bus 6	Bus 2	51.6	54
6	Bus 3	Bus 4	32.4	32.7
7	Bus 6	Bus 4	43.3	38.1
8	Bus 4	Bus 12	32.3	45.7
9	Bus 7	Bus 5	21.5	20.8
10	Bus 6	Bus 7	9.3	8.9
11	Bus 6	Bus 8	106.9	106.9
12	Bus 6	Bus 9	34.3	31.1
13	Bus 6	Bus 10	63	55.3
14	Bus 6	Bus 28	5.8	5.8
15	Bus 8	Bus 28	5.8	5.8
16	Bus 9	Bus 10	53.5	47.4
17	Bus 9	Bus 11	26.5	22.2
18	Bus 10	Bus 17	20.7	27.1

19	Bus 10	Bus 20	26.4	32.4
20	Bus 10	Bus 21	73.5	48
21	Bus 10	Bus 22	39.4	22.7
22	Bus 13	Bus 12	69.2	32.5
23	Bus 12	Bus 14	34.2	24.6
24	Bus 12	Bus 15	84.6	53.3
25	Bus 12	Bus 16	40.2	20.4
26	Bus 14	Bus 15	26.9	8.4
27	Bus 15	Bus 18	51.5	35.5
28	Bus 15	Bus 23	88	24.9
29	Bus 17	Bus 16	57.1	17.2
30	Bus 18	Bus 19	31.1	14.5
31	Bus 19	Bus 20	19.1	24.6
32	Bus 21	Bus 22	20.4	7.7
33	Bus 22	Bus 24	116.1	31.8
34	Bus 24	Bus 23	64.6	7.3
35	Bus 24	Bus 25	120.6	20.3
36	Bus 25	Bus 26	25.8	25.7
37	Bus 25	Bus 27	87.8	45.1
38	Bus 27	Bus 28	0	0
39	Bus 27	Bus 29	39.8	13.9
40	Bus 27	Bus 30	74.3	32.1
41	Bus 29	Bus 30	34.5	29.8

The addition of DG helps to alleviate the electrical load on surrounding buses. This reduction occurs because the DG generates power at the distribution end and supplies it instantly. Therefore, the congested buses experience relief due to the strategic placement of DG. Following DG placement, we conducted another OPF. Table 21 presents the percentage of MVA limit at which each line is operating, both before and after the DG placement, facilitating easier comparison.

From the table, we observe that the percentages of MVA limit upon which the branches are operating have decreased after the addition of DG at bus 30. Before the DG placement, three congested branches were identified (11, 33, 35). Branch 33 (between bus 22 and bus 24) operated at 116.1% of its MVA limit, dropping to 31.8% after the DG placement. Similarly, branch 35 (between bus 24 and bus 25) operated at 120% of its MVA limit before the DG placement, decreasing to 20.3% afterward. However, congestion persists on branch 11 (between bus 6 and bus 8) as its percentage of MVA limit remains high. Before the DG placement, it operated at 106.9% of its MVA limit, and this high value persists afterward. Thus, branch 11 remains congested despite the DG placement. Figure 17 illustrates the system status after the placement of DG at bus 30.

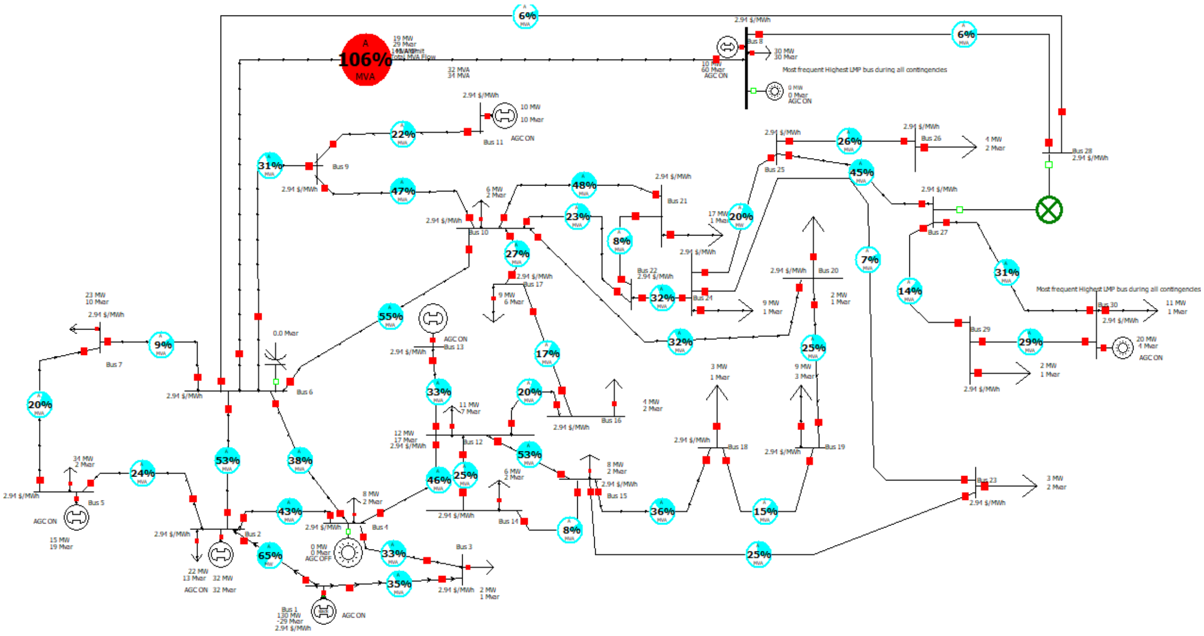

Figure 17: OPF after placing DG at bus 30 (under contingency 38)

To alleviate congestion on branch 11, the first step is to examine the power flow along the branch. Real and reactive power flows are analyzed separately to determine if reactive compensation is necessary. Figure 18 illustrates the values of real and reactive power, along with MVA limits, for the branch 11.

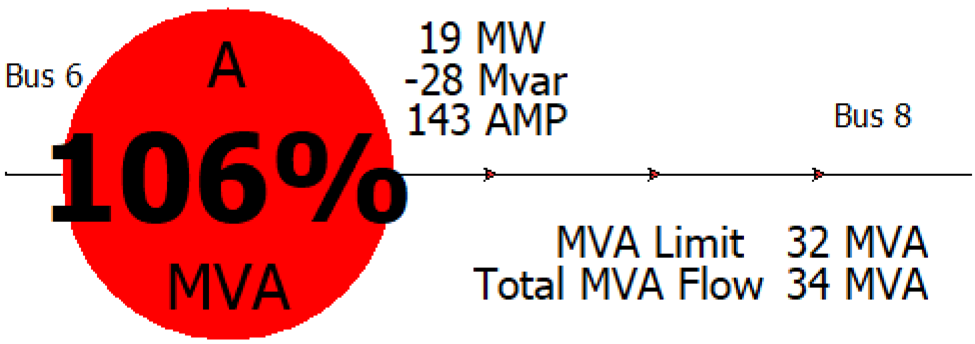

Figure 18: Power Flow between bus 6 and 8 through branch 11 (under contingency 38)

4.1.2 Removal of Congestion in branch 11

The removal of congestion at branch 11 is crucial for enhancing the flexibility of system, as branch 11 is sensitive to all the contingencies. By observing the real and reactive power flow from the branch, we can propose two solutions for congestion removal at branch 11.

1. Congestion removal by placing FACTs devices at buses with high reactive power demand.
2. Congestion removal by placing DG at the bus with high LMP.

PWS notation indicates that branch 11 extends from bus 6 to bus 8. The negative sign of '-28 Mvar' denotes the flow of reactive power in the opposite direction, i.e., from bus 8 towards bus 6, indicating a demand of '28 Mvar' of reactive power at bus 6. Conversely, there is a demand of '19 MW' of real power at bus 8. Therefore, we can alleviate the congestion either through reactive compensation at bus 6 or by providing real power generation at bus 8.

4.1.2.1 Addition of FACTs device on bus

To address reactive congestion, FACTs devices such as synchronous condensers or capacitive compensation devices can be utilized to compensate for the MVAR flow through the congested branch. The following steps outline the process for congestion removal using FACTs devices.

1. Perform OPF on the system and identify the congested branches.
2. Calculate the real and reactive power flow from those branches.
3. Identify the branch where reactive power exceeds real power flow.
4. Remember the sign convention to determine the direction of power flow; a negative sign indicates power flowing towards the reference bus.
5. The direction of reactive power flow indicates the bus with a demand for reactive power.
6. Once the bus with reactive power demand is identified, place the FACTs device to compensate for the reactive power demand.

We can estimate the size of reactive power compensator by observing the reactive power flow through branch 11. Here, we observe a high 28 Mvar flow from bus 8 towards bus 6 through branch 11. It's important to note that at this point, our system status includes a contingency at branch 38, a DG placed at bus 30, and now, a reactive compensation device placed at bus 6 as depicted in Figure 19. Table 22 presents the percentage of MVA limits on each branch before and after the placement of FACTs devices on bus 6, for ease of our comparison.

Table 22: % of MVA limit for each branch before and after FACTs device on bus 6 (under contingency 38)

Branch no	From Name	To Name	% of MVA Limit (Before)	% of MVA Limit (After)
1	Bus 1	Bus 2	68.4	68.2
2	Bus 1	Bus 3	34.8	35
3	Bus 2	Bus 4	42.8	43
4	Bus 2	Bus 5	24.4	24.3

5	Bus 6	Bus 2	54	54.7
6	Bus 3	Bus 4	32.7	33.1
7	Bus 6	Bus 4	38.1	40.4
8	Bus 4	Bus 12	45.7	45.6
9	Bus 7	Bus 5	20.8	18.6
10	Bus 6	Bus 7	8.9	9.4
11	Bus 6	Bus 8	106.9	87.3
12	Bus 6	Bus 9	31.1	30.9
13	Bus 6	Bus 10	55.3	56.5
14	Bus 6	Bus 28	5.8	4.7
15	Bus 8	Bus 28	5.8	4.8
16	Bus 9	Bus 10	47.4	47.4
17	Bus 9	Bus 11	22.2	20.9
18	Bus 10	Bus 17	27.1	27.5
19	Bus 10	Bus 20	32.4	32.6
20	Bus 10	Bus 21	48	48.1
21	Bus 10	Bus 22	22.7	22.8
22	Bus 13	Bus 12	32.5	31.1
23	Bus 12	Bus 14	24.6	24.5
24	Bus 12	Bus 15	53.3	53.2
25	Bus 12	Bus 16	20.4	20.3
26	Bus 14	Bus 15	8.4	8.3
27	Bus 15	Bus 18	35.5	35.3
28	Bus 15	Bus 23	24.9	24.8
29	Bus 17	Bus 16	17.2	17.2
30	Bus 18	Bus 19	14.5	14.4
31	Bus 19	Bus 20	24.6	24.8
32	Bus 21	Bus 22	7.7	7.8
33	Bus 22	Bus 24	31.8	32.3
34	Bus 24	Bus 23	7.3	7.4
35	Bus 24	Bus 25	20.3	20.3
36	Bus 25	Bus 26	25.7	25.7
37	Bus 25	Bus 27	45.1	44.7
38	Bus 27	Bus 28	0	0
39	Bus 27	Bus 29	13.9	13.7
40	Bus 27	Bus 30	68.4	31.9
41	Bus 29	Bus 30	34.8	29.7

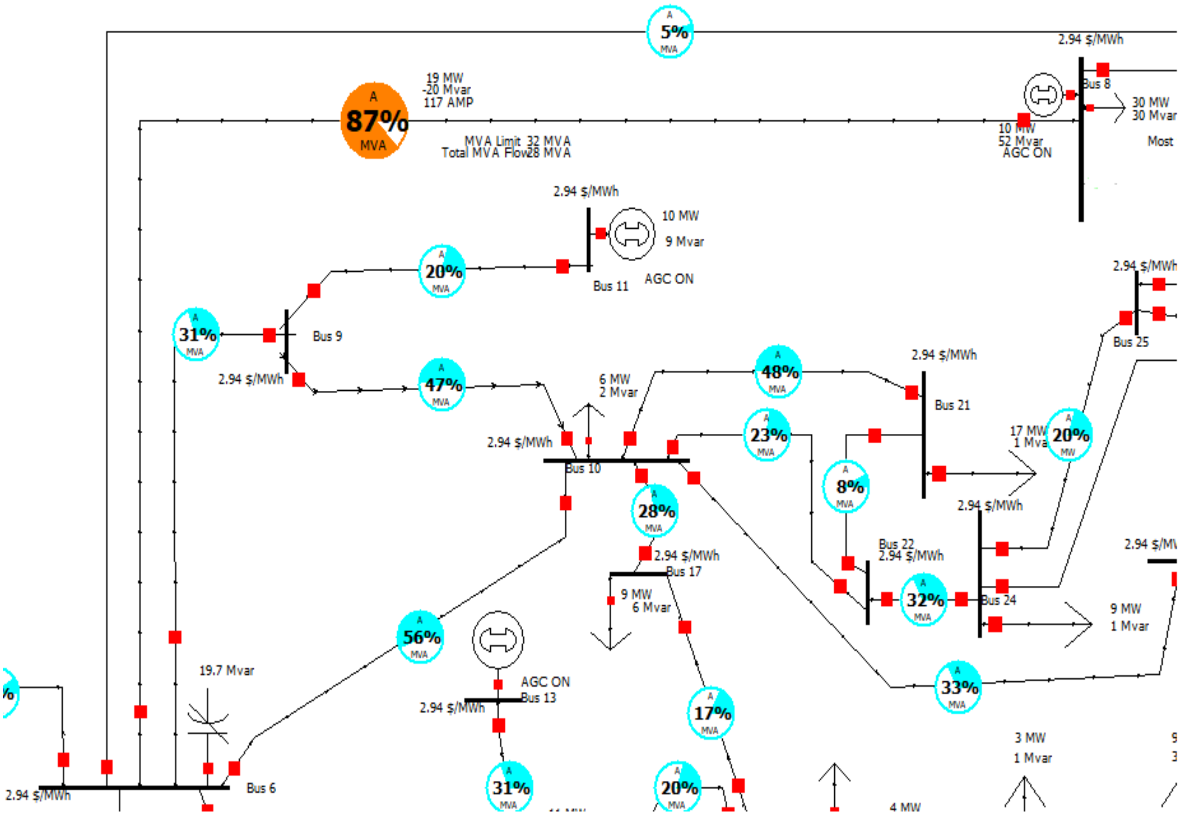

Figure 19: MVAR compensation through FACTs device in branch 11 (under contingency 38)

After the placement of FACTs device for reactive compensation at bus 6, we observe from Table 22 that the percentage of MVA limit on which branch 11 was operating dropped from 106.9% to 87.3%. This decrease was due to the reduction in reactive power flowing through the branch. Before the placement of the FACTs device, the value of reactive power flow from bus 8 to bus 6 was 28 Mvar, which decreased to 20 Mvar after the placement. This reduction occurred because of the reactive power compensation device installed on bus 6. By supplying reactive power locally, the FACTs device reduced the Mvar flow in branch 11.

4.1.2.2 Placement of DG

For the removal of congestion on branch 11, we can also introduce DG into the system at strategic place. Following steps lead to strategic placement of DG:

1. Perform OPF on the power system and identify the congested branches.
2. Calculate LMP at each bus.
3. Identify the buses with the highest LMPs.
4. Generate data for contingencies throughout the system.
5. Identify the bus with the highest LMPs frequently observed throughout the analysis.
6. Select these buses as optimal locations for placing DGs.

For our analysis of the IEEE 30 bus system, we systematically placed contingencies on each branch, conducting OPF simulations for each situation. For each contingency, we compiled the data for LMPs on each bus, as presented in Appendix B. With this compiled data, we can readily identify buses that frequently exhibit high LMPs. The following table presents the buses with frequently high LMPs.

Table 23: Buses with frequently elevated LMPs

Bus Name	Number of times with Highest LMP	Contingency Name
Bus 8	5	8, 12, 14, 16. 33
Bus 30	4	1, 2, 6, 38

The Table 23 highlights that bus 8 consistently has the highest LMP during contingencies (8, 12, 14, 16, and 33). Therefore, to mitigate this issue, we propose placing a DG unit on bus 8. We can estimate the required capacity of the DG by observing the real power flow on branch 11. Based on the data provided in Figure 18, we estimate a requirement of 20 MW with an average operation cost of $2.5/MWh for the DG placement. The simulation for DG on bus 8 is shown in Figure 21. Figure 20 shows the branch 11 status after the placement of DG.

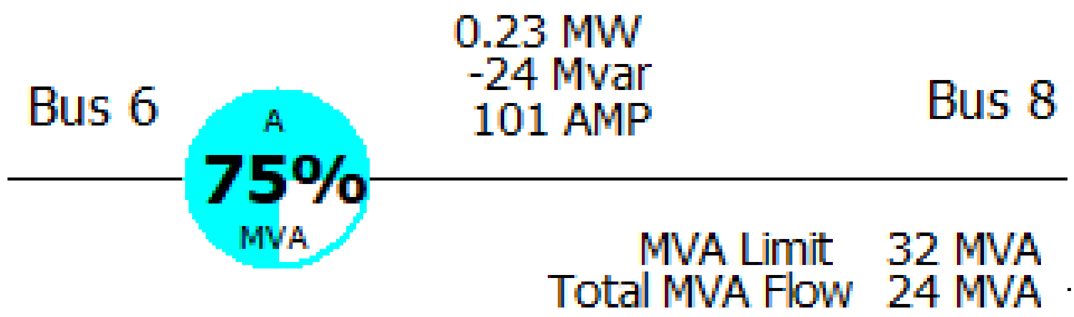

Figure 20: Power flow in branch 11 after DG placement (under contingency 38)

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Table 24From Figure 20, it is evident that the congestion has been alleviated from branch 11, as the percentage of MVA limit for this branch has dropped from 106.9% to 75.6%. The figure illustrates that the branch is now supplying only 0.23 MW of real power, while primarily providing reactive power to bus 6. In the event of another contingency, this branch is expected to remain flexible and provide support as needed. For ease of comparison Table 24 presents the percentage of MVA for branches before and after the placement of the DG on bus 8.

Table 24: % of MVA limit for each branch before and after DG placement on bus 8 (under contingency 38)

Branch no	From Name	To Name	% of MVA Limit (Before)	% of MVA Limit (After)
1	Bus 1	Bus 2	68.4	57.6
2	Bus 1	Bus 3	34.8	29.6
3	Bus 2	Bus 4	42.8	36.8
4	Bus 2	Bus 5	24.4	22.2
5	Bus 6	Bus 2	54	44.4
6	Bus 3	Bus 4	32.7	27.7
7	Bus 6	Bus 4	38.1	27
8	Bus 4	Bus 12	45.7	45.4
9	Bus 7	Bus 5	20.8	18.2
10	Bus 6	Bus 7	8.9	11
11	Bus 6	Bus 8	106.9	75.6
12	Bus 6	Bus 9	31.1	32.5
13	Bus 6	Bus 10	55.3	56.7
14	Bus 6	Bus 28	5.8	4.1
15	Bus 8	Bus 28	5.8	4.1
16	Bus 9	Bus 10	47.4	48.7
17	Bus 9	Bus 11	22.2	21.6
18	Bus 10	Bus 17	27.1	27.8
19	Bus 10	Bus 20	32.4	33
20	Bus 10	Bus 21	48	49.8
21	Bus 10	Bus 22	22.7	23.9
22	Bus 13	Bus 12	32.5	31.8
23	Bus 12	Bus 14	24.6	24.6
24	Bus 12	Bus 15	53.3	53.4
25	Bus 12	Bus 16	20.4	19.6
26	Bus 14	Bus 15	8.4	8.4
27	Bus 15	Bus 18	35.5	34.3
28	Bus 15	Bus 23	24.9	26.5
29	Bus 17	Bus 16	17.2	15.7
30	Bus 18	Bus 19	14.5	13.3
31	Bus 19	Bus 20	24.6	25.2
32	Bus 21	Bus 22	7.7	5.6
33	Bus 22	Bus 24	31.8	37
34	Bus 24	Bus 23	7.3	9.6
35	Bus 24	Bus 25	20.3	12.9
36	Bus 25	Bus 26	25.7	25.7
37	Bus 25	Bus 27	45.1	38.5
38	Bus 27	Bus 28	0	0
39	Bus 27	Bus 29	13.9	11.2

40	Bus 27	Bus 30	68.4	27.8
41	Bus 29	Bus 30	34.8	26.7

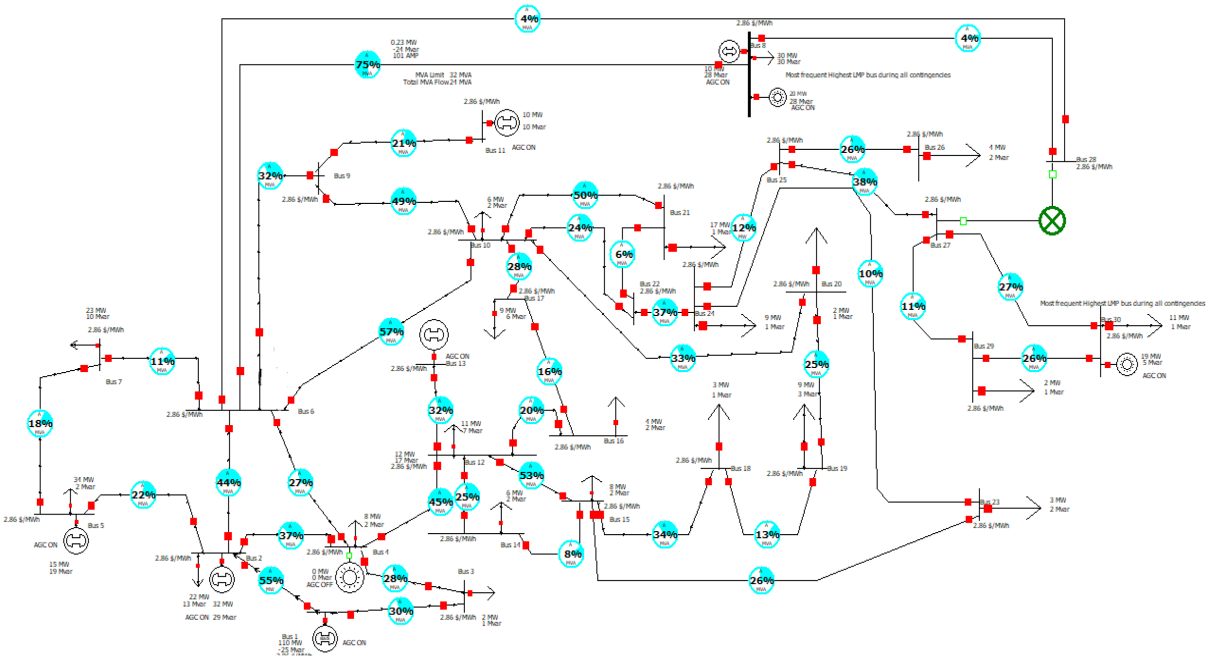

Figure 21: Placement of DG on bus 8

At this point, we have explored both techniques for congestion mitigation in branch 11. Using FACTs devices, we found limited flexibility, leaving the system vulnerable to congestion, especially considering that buses 8 and 30 frequently exhibit elevated LMPs. Even with compensating reactive power by placing FACTs devices on bus 6, congestion remains likely in other contingencies where these buses are affected. Through our analysis of both techniques, we conclude that the placement of DG offers greater flexibility in mitigating congestion.

5 Results and discussion

Our procedure began by systematically introducing faults to each branch in the IEEE 30 bus system and studying their effects on the system. Following the placement of each contingency, we conducted OPF analysis and calculated LMPs for each bus. The resulting data were compiled into tables presented in both Appendix A and Appendix B, facilitating our exploration of the system's sensitivity. Through this analysis, we identified branch 38 (between bus 27 and bus 28) as the most sensitive, inducing congestion on multiple branches (11, 33, and 35). Notably, during contingency 38, bus 30 exhibited the highest LMP. We initiated our DG placement strategy from bus 30, which partially alleviated congestion by resolving issues in branches 33 and 35, though congestion persisted in branch 11 due to reactive power violations.

To address this, we proposed two solutions: the placement of FACTs (Flexible Alternating Current Transmission Systems) devices or adding DG. For FACTs devices placement, we observed the reactive power flow towards bus 6 and installed a device accordingly. This intervention successfully removed all congestion during contingency 38.

On the other hand, another solution to remove congestion on branch 11 is to install a DG unit. We compiled data on buses with frequently elevated LMPs during contingency cases in branch simulations, as shown in Table 19. Notably, bus 8 consistently exhibits the highest LMP during contingencies. Placing a DG on this bus would effectively remove congestion from branch 11 and enhance the system's flexibility by providing distributed generation in other contingency scenarios as well.

In summary, installing DG units on both bus 8 and bus 30 would effectively eliminate congestion across all contingencies. This solution addresses the sensitivity of branch 11, between bus 6 and bus 8, which remains the most congested branch in the unmodified IEEE bus system, as observed from the data in Table 18 from contingency simulations.

5.1 Enhancement of flexibility

The flexibility of the modified system is dependent upon the capabilities of the RES installed on the buses. While solar renewable energy sources DGs are suitable for sunny regions, they have limitations due to the limited hours of the day when they can generate energy. In contrast, wind power could serve as an alternative DG in windy areas, where the probability curve of wind supports feasible power generation.

To further enhance the system's flexibility and reliability, backup systems capable of storing power for extended periods could be employed. These backup systems would provide power during high load periods or contingencies, thereby strengthening system reliability. For example, in the event of a contingency or overload during night-time hours when solar DGs may be inactive, a backup system charged by solar RES during daylight hours could sufficiently support the system. Similarly, during periods of low wind generation, a backup system charged by wind RES during windy periods could effectively alleviate congestion and ensure system stability.

5.2 Designing control strategy with the help of Relays

To develop a control strategy, we installed sensory devices, such as protection relays, on each branch for overloading or congestion conditions. These relays require configuration to set tripping values. Tripping values are established based on the MVA limits of each branch, with the assumption that a branch operating at 95% of its MVA limit is critical and prone to congestion with even a small additional load. The relays employed here are over-current relays, which operate by detecting current violations. Upon detecting an overcurrent condition, these relays trigger a trip signal. Setting pickup values involves converting MVA values to amperes given by the following formula.

$$Amperage\ Limit = \frac{MVA\ Limit}{Voltage\ Level} \tag{5.1}$$

This way we can calculate the corresponding amperes for our desired MVA limit. The next step is to attach these relays to the system, requiring the placement of current transformers (CTs) to provide the relay with a safe current for sensing. The CT ratio is set to step down the current to a level easily sensed by the relay. Additionally, the outputs of the trip signals need to be defined, which are then fed to circuit breakers to toggle them open.

There are two types of overcurrent relays: “Instantaneous overcurrent relay” and “Definite time overcurrent relay”. As its name suggests, the instantaneous overcurrent relay initiates a trip signal as soon as the overcurrent condition is sensed, while the definite time overcurrent relay senses the overcurrent and initiates the trip signal after a specified time delay. We opt for the definite time overcurrent relay, as we are providing a limit with some margin. Following is the flow chart of our control strategy.

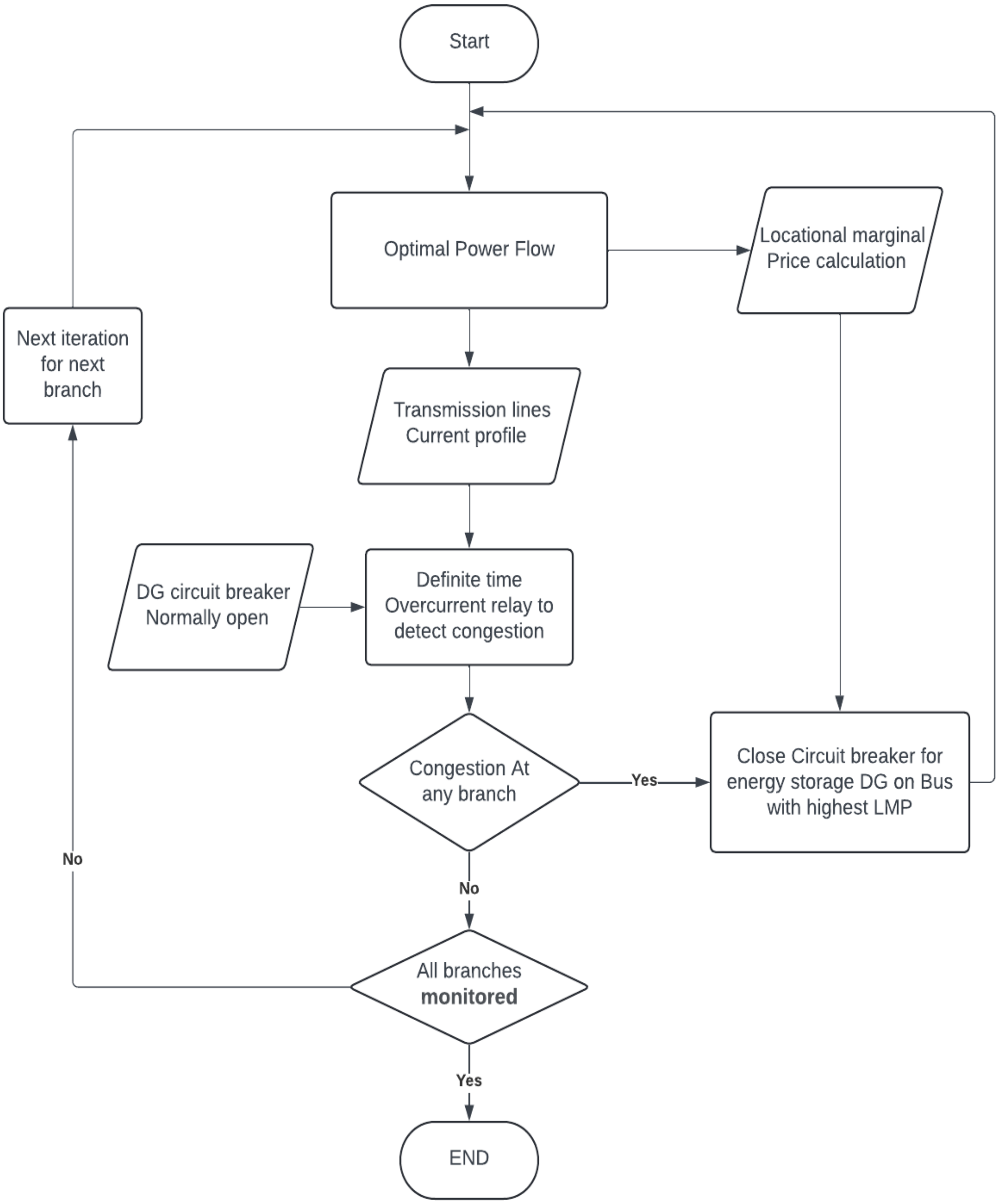

Figure 22: Flow Chart of control strategy

After the placement of the DG and its backup system, a circuit breaker is installed on the DG to isolate it from the system during normal conditions, ensuring uninterrupted charging of the backup system. Consequently, the circuit breaker remains normally open. To implement the control strategy, overcurrent relays are positioned at each branch to detect congestion. The pickup values of these relays are set in amperes, and their trip signal outputs are connected to circuit breakers. These signals control the opening or closing of the circuit breakers based on the control strategy.

In our strategy, when congestion is detected, the relay initiates a trip signal, which is then sent to the normally open circuit breaker at the DG. This signal closes the circuit breaker, connecting the DG to the system. The DG then enters the congested system and promptly provides distributed generation to manage the congestion. This approach enhances the system's flexibility, enabling it to effectively address congestion on any transmission line at risk of becoming congested due to additional load or contingencies.

To demonstrate the effectiveness of this strategy, we will apply it to the IEEE 3 bus system, as shown in Figure 23, where a battery backup system is attached via a circuit breaker (CB1) to Bus 2.

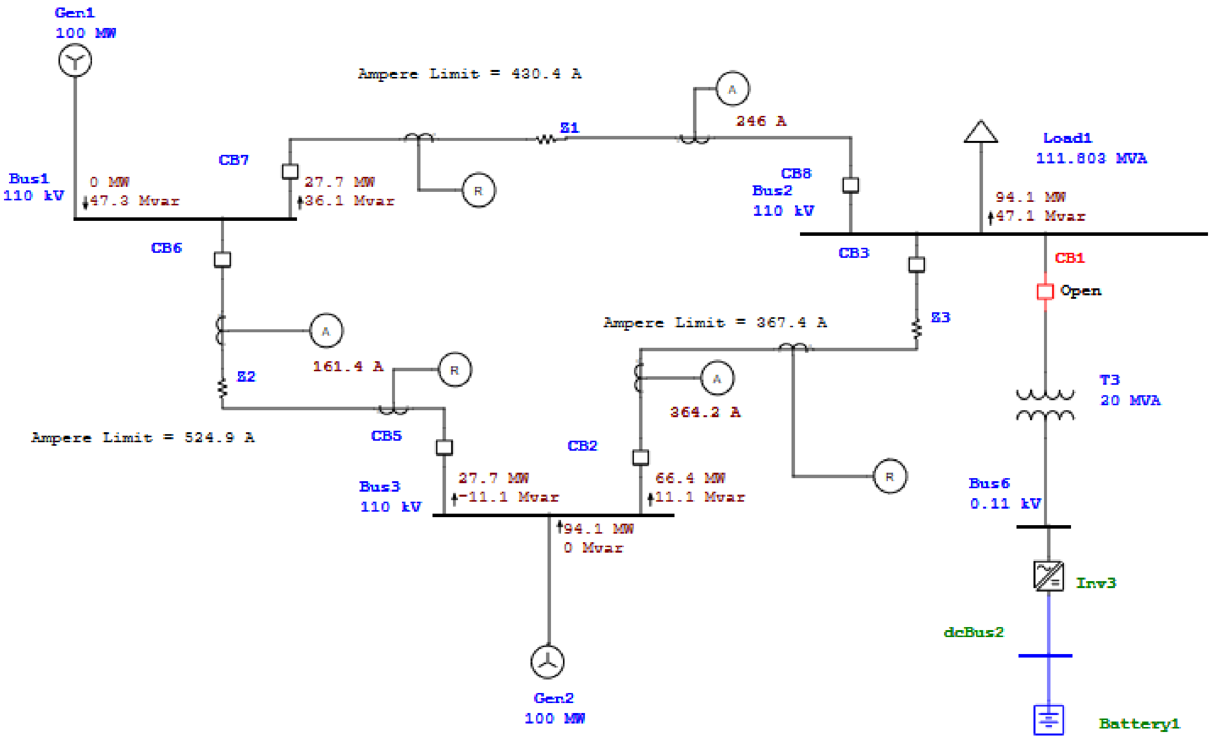

Figure 23: Overcurrent Relay not tripped CB1 open

Table 25: IEEE 3 bus system Ampere profile before closing CB1

Branch no	From Bus	To Bus	Amperes Limit	Ammeter reading	%Ampere
1	1	2	430.4	246	57.1
2	1	3	524.9	161.4	30.7
3	2	3	367.4	364	99.0

From Table 25, we can observe that branch 3 is experiencing congestion as it is operating at 99% of its ampere rating. Hence, the overcurrent relay senses the congestion and initiates the trip signal. This trip signal is then routed to the circuit breaker (CB1) at bus 2. According to our control strategy, this signal closes the circuit breaker. Once CB1 is closed, it indicates that the BESS has entered the system and will clear the congestion. The Figure 24 below illustrates the system configuration upon the closing of CB1:

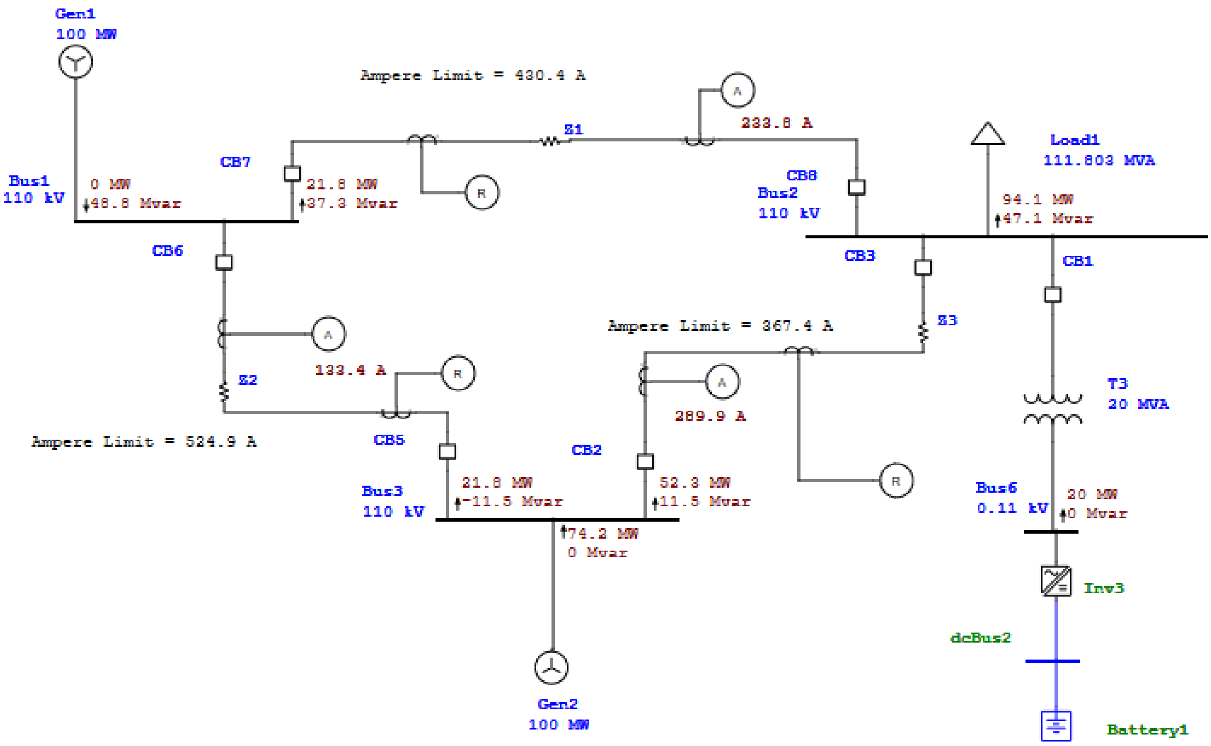

Figure 24: Overcurrent Relay tripped CB1 closed

Table 26: IEEE 3 bus system Ampere profile after closing CB1

Branch no	From Bus	To Bus	Amperes Limit	Ammeter reading	%Ampere
1	1	2	430.4	233.8	54.3
2	1	3	524.9	133.4	25.4
3	2	3	367.4	267.4	72.7

Here we observe that the relay has detected the congestion and closed the circuit breaker CB1, integrating the storage system into the network. Consequently, the congestion on branch 3 has been removed as depicted in Table 26: IEEE 3 bus system Ampere profile after closing CB1. However, relying solely on the relay system to detect congestion poses a potential issue: as soon as the storage system enters the network and removes congestion, the relay may no longer detect congestion, causing it to cease providing the trip signal. As a result, CB1 may reopen, disconnecting the battery from the system. This scenario could lead to the relay toggling on and off repeatedly.

To address this situation, we can implement a definite time delay in the relay system before it checks the load condition on the branch. This delay ensures that the relay maintains stability and does not react immediately to transient changes in system conditions, preventing unnecessary toggling of CB1 and ensuring continuous operation.

5.3 Limitations of thesis

Following are some of the key limitations of this thesis:

1. The software used for power system analysis is Power World Simulator (PWS). This software does not offer any DC power sources.
2. Mostly, solar renewable energy sources (RES) are used for DG. For the analysis of solar RES, we need a DC source and an inverter. To accommodate this, we considered an AC source as the RES. The values taken for this AC source are equivalent to the AC output of a solar RES. In summary, we combined the DC source, inverter, and transformer into a single AC source.
3. Each RES used for congestion management requires an energy storage backup system for enhanced flexibility. The study of battery backup systems is beyond the scope of this thesis.
4. The control strategy is designed using relays. Other approaches, such as microcontroller-based DG activation systems, can also be implemented.

5.4 Future work

Future research efforts can focus on developing methods to integrate bulk energy storage solutions that can effectively complement RES and provide robust backup capabilities. While battery-based energy storage systems (BESS) offer a promising option, the scalability of BESS for large-scale energy storage remains a challenge, highlighting the need for further research in this area. Fuel cells represent another avenue for storing energy at scale, presenting an alternative solution worth exploring.

However, given current limitations, incentivizing consumers to adopt backup systems connected to the main grid emerges as a practical and feasible approach. By encouraging more consumers to participate in energy storage initiatives, a collective energy storage pool can be created. In the event of contingencies or overloading situations, market operators can propose appropriate unit costs for consumers to purchase energy from this backup pool, ensuring system reliability and resilience.

6 Conclusion

In conclusion, this thesis presents a practical solution for mitigating congestion in the IEEE 30 bus system by strategically deploying DG at buses with high LMPs. Through this approach, the LMP on all buses is effectively reduced, leading to the removal of congestion. Additionally, the thesis explores the use of FACTs devices as an alternative method for congestion removal, comparing its effectiveness with RES placement.

Furthermore, the thesis proposes strategies to enhance system flexibility by introducing energy backup systems, along with a control strategy for automated backup addition based on overloading conditions. A roadmap for managing energy storage during congestion periods is outlined, involving the procurement of excess energy from consumers' backup systems.

Overall, this research not only addresses the challenge of congestion in power systems but also offers practical solutions to improve system flexibility, reliability, and resilience in the face of dynamic operating conditions.

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Appendix A

Appendix A Table 1 %MVA by limit under contingency of branch 1

Branch no	From Name	To Name	Branch Device Type	% of MVA Limit
1	Bus 1	Bus 2	Line	0
2	Bus 1	Bus 3	Line	100
3	Bus 2	Bus 4	Line	24.1
4	Bus 2	Bus 5	Line	13.7
5	Bus 6	Bus 2	Line	22.2
6	Bus 3	Bus 4	Line	96.3
7	Bus 6	Bus 4	Line	85.8
8	Bus 4	Bus 12	Transformer	52.8
9	Bus 7	Bus 5	Line	23.5
10	Bus 6	Bus 7	Line	14.4
11	Bus 6	Bus 8	Line	116.5
12	Bus 6	Bus 9	Transformer	31.6
13	Bus 6	Bus 10	Transformer	55.4
14	Bus 6	Bus 28	Line	17.1
15	Bus 8	Bus 28	Line	33.2
16	Bus 9	Bus 10	Line	48.6
17	Bus 9	Bus 11	Line	25.9
18	Bus 10	Bus 17	Line	23.7
19	Bus 10	Bus 20	Line	30.6
20	Bus 10	Bus 21	Line	53.3
21	Bus 10	Bus 22	Line	26.2
22	Bus 13	Bus 12	Line	37.3
23	Bus 12	Bus 14	Line	26.8
24	Bus 12	Bus 15	Line	60.6
25	Bus 12	Bus 16	Line	25.2
26	Bus 14	Bus 15	Line	12.7
27	Bus 15	Bus 18	Line	39.6
28	Bus 15	Bus 23	Line	39.1
29	Bus 17	Bus 16	Line	26.7
30	Bus 18	Bus 19	Line	18.6
31	Bus 19	Bus 20	Line	22.9
32	Bus 21	Bus 22	Line	6.5
33	Bus 22	Bus 24	Line	50.4
34	Bus 24	Bus 23	Line	17.4
35	Bus 24	Bus 25	Line	18.3
36	Bus 25	Bus 26	Line	25.7
37	Bus 25	Bus 27	Line	14.9
38	Bus 27	Bus 28	Transformer	24.4
39	Bus 27	Bus 29	Line	39.5
40	Bus 27	Bus 30	Line	45
41	Bus 29	Bus 30	Line	23.3

Appendix A Table 2 %MVA by limit under contingency of branch 2

Branch no	From Name	To Name	Branch Device Type	% of MVA Limit
1	Bus 1	Bus 2	Line	104.1
2	Bus 1	Bus 3	Line	0
3	Bus 2	Bus 4	Line	83.8
4	Bus 2	Bus 5	Line	29.4
5	Bus 6	Bus 2	Line	87.5
6	Bus 3	Bus 4	Line	2.1
7	Bus 6	Bus 4	Line	17
8	Bus 4	Bus 12	Transformer	46.8
9	Bus 7	Bus 5	Line	37.8
10	Bus 6	Bus 7	Line	1.6
11	Bus 6	Bus 8	Line	117.7
12	Bus 6	Bus 9	Transformer	34.8
13	Bus 6	Bus 10	Transformer	58.1
14	Bus 6	Bus 28	Line	17.6
15	Bus 8	Bus 28	Line	34.3
16	Bus 9	Bus 10	Line	51.4
17	Bus 9	Bus 11	Line	26.1
18	Bus 10	Bus 17	Line	26.3
19	Bus 10	Bus 20	Line	33
20	Bus 10	Bus 21	Line	54.1
21	Bus 10	Bus 22	Line	26.7
22	Bus 13	Bus 12	Line	38
23	Bus 12	Bus 14	Line	25.4
24	Bus 12	Bus 15	Line	56.4
25	Bus 12	Bus 16	Line	20.4
26	Bus 14	Bus 15	Line	10.2
27	Bus 15	Bus 18	Line	34.1
28	Bus 15	Bus 23	Line	33.8
29	Bus 17	Bus 16	Line	16
30	Bus 18	Bus 19	Line	13
31	Bus 19	Bus 20	Line	25.2
32	Bus 21	Bus 22	Line	6
33	Bus 22	Bus 24	Line	52.7
34	Bus 24	Bus 23	Line	11.3
35	Bus 24	Bus 25	Line	19.1
36	Bus 25	Bus 26	Line	25.7
37	Bus 25	Bus 27	Line	18.9
38	Bus 27	Bus 28	Transformer	25.3
39	Bus 27	Bus 29	Line	39.5
40	Bus 27	Bus 30	Line	45
41	Bus 29	Bus 30	Line	23.3

Appendix A Table 3 %MVA by limit under contingency of branch 3

Branch no	From Name	To Name	Branch Device Type	% of MVA Limit
1	Bus 1	Bus 2	Line	62.4
2	Bus 1	Bus 3	Line	48.5
3	Bus 2	Bus 4	Line	0
4	Bus 2	Bus 5	Line	32.5
5	Bus 6	Bus 2	Line	88
6	Bus 3	Bus 4	Line	45.8
7	Bus 6	Bus 4	Line	25.3
8	Bus 4	Bus 12	Transformer	47.7
9	Bus 7	Bus 5	Line	34.5
10	Bus 6	Bus 7	Line	1.3
11	Bus 6	Bus 8	Line	128.1
12	Bus 6	Bus 9	Transformer	34.6
13	Bus 6	Bus 10	Transformer	57.6
14	Bus 6	Bus 28	Line	18.3
15	Bus 8	Bus 28	Line	33
16	Bus 9	Bus 10	Line	51.1
17	Bus 9	Bus 11	Line	26.4
18	Bus 10	Bus 17	Line	25.8
19	Bus 10	Bus 20	Line	32.7
20	Bus 10	Bus 21	Line	54.1
21	Bus 10	Bus 22	Line	26.7
22	Bus 13	Bus 12	Line	38.4
23	Bus 12	Bus 14	Line	25.6
24	Bus 12	Bus 15	Line	57
25	Bus 12	Bus 16	Line	21
26	Bus 14	Bus 15	Line	10.6
27	Bus 15	Bus 18	Line	34.8
28	Bus 15	Bus 23	Line	34.8
29	Bus 17	Bus 16	Line	17.4
30	Bus 18	Bus 19	Line	13.7
31	Bus 19	Bus 20	Line	24.9
32	Bus 21	Bus 22	Line	6
33	Bus 22	Bus 24	Line	52.9
34	Bus 24	Bus 23	Line	12.3
35	Bus 24	Bus 25	Line	19.3
36	Bus 25	Bus 26	Line	25.7
37	Bus 25	Bus 27	Line	17.7
38	Bus 27	Bus 28	Transformer	25
39	Bus 27	Bus 29	Line	39.5
40	Bus 27	Bus 30	Line	45
41	Bus 29	Bus 30	Line	23.3

Appendix A Table 4 %MVA by limit under contingency of branch 4

Branch no	From Name	To Name	Branch Device Type	% of MVA Limit
1	Bus 1	Bus 2	Line	67.1
2	Bus 1	Bus 3	Line	45.2
3	Bus 2	Bus 4	Line	70.1
4	Bus 2	Bus 5	Line	0
5	Bus 6	Bus 2	Line	90.7
6	Bus 3	Bus 4	Line	42.8
7	Bus 6	Bus 4	Line	67.3
8	Bus 4	Bus 12	Transformer	51.2
9	Bus 7	Bus 5	Line	45.2
10	Bus 6	Bus 7	Line	34.4
11	Bus 6	Bus 8	Line	127.3
12	Bus 6	Bus 9	Transformer	32.4
13	Bus 6	Bus 10	Transformer	56.2
14	Bus 6	Bus 28	Line	17.9
15	Bus 8	Bus 28	Line	32.4
16	Bus 9	Bus 10	Line	49.2
17	Bus 9	Bus 11	Line	25.4
18	Bus 10	Bus 17	Line	24.1
19	Bus 10	Bus 20	Line	31.1
20	Bus 10	Bus 21	Line	53.6
21	Bus 10	Bus 22	Line	26.4
22	Bus 13	Bus 12	Line	36.3
23	Bus 12	Bus 14	Line	26.5
24	Bus 12	Bus 15	Line	59.7
25	Bus 12	Bus 16	Line	24
26	Bus 14	Bus 15	Line	12.1
27	Bus 15	Bus 18	Line	38.2
28	Bus 15	Bus 23	Line	38
29	Bus 17	Bus 16	Line	24
30	Bus 18	Bus 19	Line	17.2
31	Bus 19	Bus 20	Line	23.4
32	Bus 21	Bus 22	Line	6.2
33	Bus 22	Bus 24	Line	51.3
34	Bus 24	Bus 23	Line	16.1
35	Bus 24	Bus 25	Line	18.6
36	Bus 25	Bus 26	Line	25.7
37	Bus 25	Bus 27	Line	15.2
38	Bus 27	Bus 28	Transformer	24.5
39	Bus 27	Bus 29	Line	39.5
40	Bus 27	Bus 30	Line	45
41	Bus 29	Bus 30	Line	23.3

Appendix A Table 5 %MVA by limit under contingency of branch 5

Branch no	From Name	To Name	Branch Device Type	% of MVA Limit
1	Bus 1	Bus 2	Line	63
2	Bus 1	Bus 3	Line	48.4
3	Bus 2	Bus 4	Line	81.1
4	Bus 2	Bus 5	Line	36.5
5	Bus 6	Bus 2	Line	0
6	Bus 3	Bus 4	Line	45.7
7	Bus 6	Bus 4	Line	77.8
8	Bus 4	Bus 12	Transformer	52.5
9	Bus 7	Bus 5	Line	40.6
10	Bus 6	Bus 7	Line	2.5
11	Bus 6	Bus 8	Line	127.1
12	Bus 6	Bus 9	Transformer	32.2
13	Bus 6	Bus 10	Transformer	54.8
14	Bus 6	Bus 28	Line	17.8
15	Bus 8	Bus 28	Line	32
16	Bus 9	Bus 10	Line	48.8
17	Bus 9	Bus 11	Line	27.2
18	Bus 10	Bus 17	Line	23.1
19	Bus 10	Bus 20	Line	30.5
20	Bus 10	Bus 21	Line	53.5
21	Bus 10	Bus 22	Line	26.3
22	Bus 13	Bus 12	Line	38.1
23	Bus 12	Bus 14	Line	26.8
24	Bus 12	Bus 15	Line	60.7
25	Bus 12	Bus 16	Line	25.1
26	Bus 14	Bus 15	Line	12.7
27	Bus 15	Bus 18	Line	39.4
28	Bus 15	Bus 23	Line	39.5
29	Bus 17	Bus 16	Line	26.1
30	Bus 18	Bus 19	Line	18.4
31	Bus 19	Bus 20	Line	22.8
32	Bus 21	Bus 22	Line	6.3
33	Bus 22	Bus 24	Line	51.1
34	Bus 24	Bus 23	Line	17.4
35	Bus 24	Bus 25	Line	19.6
36	Bus 25	Bus 26	Line	25.7
37	Bus 25	Bus 27	Line	14.4
38	Bus 27	Bus 28	Transformer	24.2
39	Bus 27	Bus 29	Line	39.5
40	Bus 27	Bus 30	Line	45.1
41	Bus 29	Bus 30	Line	23.3

Appendix A Table 6 %MVA by limit under contingency of branch 6

Branch no	From Name	To Name	Branch Device Type	% of MVA Limit
1	Bus 1	Bus 2	Line	104.1
2	Bus 1	Bus 3	Line	2.1
3	Bus 2	Bus 4	Line	83.4
4	Bus 2	Bus 5	Line	29.5
5	Bus 6	Bus 2	Line	87.8
6	Bus 3	Bus 4	Line	0
7	Bus 6	Bus 4	Line	18.5
8	Bus 4	Bus 12	Transformer	46.9
9	Bus 7	Bus 5	Line	37.8
10	Bus 6	Bus 7	Line	1.7
11	Bus 6	Bus 8	Line	122.5
12	Bus 6	Bus 9	Transformer	34.7
13	Bus 6	Bus 10	Transformer	58
14	Bus 6	Bus 28	Line	17.9
15	Bus 8	Bus 28	Line	33.8
16	Bus 9	Bus 10	Line	51.3
17	Bus 9	Bus 11	Line	25.9
18	Bus 10	Bus 17	Line	26.2
19	Bus 10	Bus 20	Line	32.9
20	Bus 10	Bus 21	Line	54.1
21	Bus 10	Bus 22	Line	26.7
22	Bus 13	Bus 12	Line	37.7
23	Bus 12	Bus 14	Line	25.4
24	Bus 12	Bus 15	Line	56.5
25	Bus 12	Bus 16	Line	20.5
26	Bus 14	Bus 15	Line	10.3
27	Bus 15	Bus 18	Line	34.3
28	Bus 15	Bus 23	Line	34.1
29	Bus 17	Bus 16	Line	16.3
30	Bus 18	Bus 19	Line	13.2
31	Bus 19	Bus 20	Line	25.1
32	Bus 21	Bus 22	Line	5.9
33	Bus 22	Bus 24	Line	52.8
34	Bus 24	Bus 23	Line	11.6
35	Bus 24	Bus 25	Line	19.1
36	Bus 25	Bus 26	Line	25.7
37	Bus 25	Bus 27	Line	18.4
38	Bus 27	Bus 28	Transformer	25.2
39	Bus 27	Bus 29	Line	39.5
40	Bus 27	Bus 30	Line	45
41	Bus 29	Bus 30	Line	23.3

Appendix A Table 7 %MVA by limit under contingency of branch 7

Branch no	From Name	To Name	Branch Device Type	% of MVA Limit
1	Bus 1	Bus 2	Line	82.1
2	Bus 1	Bus 3	Line	29.9
3	Bus 2	Bus 4	Line	25
4	Bus 2	Bus 5	Line	34.6
5	Bus 6	Bus 2	Line	97.9
6	Bus 3	Bus 4	Line	27.6
7	Bus 6	Bus 4	Line	0
8	Bus 4	Bus 12	Transformer	66.1
9	Bus 7	Bus 5	Line	36.1
10	Bus 6	Bus 7	Line	2.3
11	Bus 6	Bus 8	Line	124
12	Bus 6	Bus 9	Transformer	24.7
13	Bus 6	Bus 10	Transformer	50.1
14	Bus 6	Bus 28	Line	16.5
15	Bus 8	Bus 28	Line	29.8
16	Bus 9	Bus 10	Line	42.6
17	Bus 9	Bus 11	Line	25.7
18	Bus 10	Bus 17	Line	22.1
19	Bus 10	Bus 20	Line	25.7
20	Bus 10	Bus 21	Line	51.6
21	Bus 10	Bus 22	Line	25.1
22	Bus 13	Bus 12	Line	35
23	Bus 12	Bus 14	Line	30
24	Bus 12	Bus 15	Line	70.8
25	Bus 12	Bus 16	Line	37.2
26	Bus 14	Bus 15	Line	19
27	Bus 15	Bus 18	Line	52.7
28	Bus 15	Bus 23	Line	52.7
29	Bus 17	Bus 16	Line	51.8
30	Bus 18	Bus 19	Line	32.2
31	Bus 19	Bus 20	Line	18.5
32	Bus 21	Bus 22	Line	7.6
33	Bus 22	Bus 24	Line	45.9
34	Bus 24	Bus 23	Line	32.3
35	Bus 24	Bus 25	Line	20.7
36	Bus 25	Bus 26	Line	25.7
37	Bus 25	Bus 27	Line	5.8
38	Bus 27	Bus 28	Transformer	22.5
39	Bus 27	Bus 29	Line	39.5
40	Bus 27	Bus 30	Line	45
41	Bus 29	Bus 30	Line	23.3

Appendix A Table 8 %MVA by limit under contingency of branch 8

Branch no	From Name	To Name	Branch Device Type	% of MVA Limit
1	Bus 1	Bus 2	Line	73.6
2	Bus 1	Bus 3	Line	37.2
3	Bus 2	Bus 4	Line	45.9
4	Bus 2	Bus 5	Line	28.2
5	Bus 6	Bus 2	Line	69.5
6	Bus 3	Bus 4	Line	35
7	Bus 6	Bus 4	Line	74.8
8	Bus 4	Bus 12	Transformer	0
9	Bus 7	Bus 5	Line	28.1
10	Bus 6	Bus 7	Line	5.3
11	Bus 6	Bus 8	Line	133.2
12	Bus 6	Bus 9	Transformer	59.8
13	Bus 6	Bus 10	Transformer	85.6
14	Bus 6	Bus 28	Line	22.8
15	Bus 8	Bus 28	Line	44.1
16	Bus 9	Bus 10	Line	75.3
17	Bus 9	Bus 11	Line	24.8
18	Bus 10	Bus 17	Line	65.7
19	Bus 10	Bus 20	Line	56.2
20	Bus 10	Bus 21	Line	60.8
21	Bus 10	Bus 22	Line	31
22	Bus 13	Bus 12	Line	45.5
23	Bus 12	Bus 14	Line	15.5
24	Bus 12	Bus 15	Line	32.9
25	Bus 12	Bus 16	Line	31.9
26	Bus 14	Bus 15	Line	18.1
27	Bus 15	Bus 18	Line	28.2
28	Bus 15	Bus 23	Line	36.5
29	Bus 17	Bus 16	Line	77.6
30	Bus 18	Bus 19	Line	39.8
31	Bus 19	Bus 20	Line	47.9
32	Bus 21	Bus 22	Line	6.8
33	Bus 22	Bus 24	Line	72.9
34	Bus 24	Bus 23	Line	45
35	Bus 24	Bus 25	Line	40.1
36	Bus 25	Bus 26	Line	25.7
37	Bus 25	Bus 27	Line	51.4
38	Bus 27	Bus 28	Transformer	32.6
39	Bus 27	Bus 29	Line	39.5
40	Bus 27	Bus 30	Line	45
41	Bus 29	Bus 30	Line	23.3

Appendix A Table 9 %MVA by limit under contingency of branch 9

Branch no	From Name	To Name	Branch Device Type	% of MVA Limit
1	Bus 1	Bus 2	Line	69.6
2	Bus 1	Bus 3	Line	41.3
3	Bus 2	Bus 4	Line	59.5
4	Bus 2	Bus 5	Line	15.3
5	Bus 6	Bus 2	Line	75.9
6	Bus 3	Bus 4	Line	38.7
7	Bus 6	Bus 4	Line	53
8	Bus 4	Bus 12	Transformer	50.4
9	Bus 7	Bus 5	Line	0
10	Bus 6	Bus 7	Line	19.5
11	Bus 6	Bus 8	Line	127.7
12	Bus 6	Bus 9	Transformer	33.6
13	Bus 6	Bus 10	Transformer	55.2
14	Bus 6	Bus 28	Line	17.9
15	Bus 8	Bus 28	Line	32.2
16	Bus 9	Bus 10	Line	49.8
17	Bus 9	Bus 11	Line	28.1
18	Bus 10	Bus 17	Line	23.7
19	Bus 10	Bus 20	Line	31.3
20	Bus 10	Bus 21	Line	53.8
21	Bus 10	Bus 22	Line	26.5
22	Bus 13	Bus 12	Line	39
23	Bus 12	Bus 14	Line	26.3
24	Bus 12	Bus 15	Line	59.4
25	Bus 12	Bus 16	Line	23.6
26	Bus 14	Bus 15	Line	12
27	Bus 15	Bus 18	Line	37.7
28	Bus 15	Bus 23	Line	37.9
29	Bus 17	Bus 16	Line	22.5
30	Bus 18	Bus 19	Line	16.5
31	Bus 19	Bus 20	Line	23.5
32	Bus 21	Bus 22	Line	6.1
33	Bus 22	Bus 24	Line	52
34	Bus 24	Bus 23	Line	15.5
35	Bus 24	Bus 25	Line	20.4
36	Bus 25	Bus 26	Line	25.7
37	Bus 25	Bus 27	Line	15.8
38	Bus 27	Bus 28	Transformer	24.4
39	Bus 27	Bus 29	Line	39.5
40	Bus 27	Bus 30	Line	45.1
41	Bus 29	Bus 30	Line	23.3

Appendix A Table 10 %MVA by limit under contingency of branch 10

Branch no	From Name	To Name	Branch Device Type	% of MVA Limit
1	Bus 1	Bus 2	Line	73.4
2	Bus 1	Bus 3	Line	37.4
3	Bus 2	Bus 4	Line	46.6
4	Bus 2	Bus 5	Line	33.8
5	Bus 6	Bus 2	Line	58.9
6	Bus 3	Bus 4	Line	35.2
7	Bus 6	Bus 4	Line	41.6
8	Bus 4	Bus 12	Transformer	48.7
9	Bus 7	Bus 5	Line	36.4
10	Bus 6	Bus 7	Line	0
11	Bus 6	Bus 8	Line	127.7
12	Bus 6	Bus 9	Transformer	33.4
13	Bus 6	Bus 10	Transformer	57.9
14	Bus 6	Bus 28	Line	18.2
15	Bus 8	Bus 28	Line	33
16	Bus 9	Bus 10	Line	50.2
17	Bus 9	Bus 11	Line	24.3
18	Bus 10	Bus 17	Line	25.4
19	Bus 10	Bus 20	Line	32.2
20	Bus 10	Bus 21	Line	53.9
21	Bus 10	Bus 22	Line	26.5
22	Bus 13	Bus 12	Line	35.2
23	Bus 12	Bus 14	Line	25.9
24	Bus 12	Bus 15	Line	57.8
25	Bus 12	Bus 16	Line	22
26	Bus 14	Bus 15	Line	11
27	Bus 15	Bus 18	Line	36
28	Bus 15	Bus 23	Line	35.6
29	Bus 17	Bus 16	Line	19.7
30	Bus 18	Bus 19	Line	14.9
31	Bus 19	Bus 20	Line	24.4
32	Bus 21	Bus 22	Line	6
33	Bus 22	Bus 24	Line	52
34	Bus 24	Bus 23	Line	13.5
35	Bus 24	Bus 25	Line	18
36	Bus 25	Bus 26	Line	25.7
37	Bus 25	Bus 27	Line	16.9
38	Bus 27	Bus 28	Transformer	24.9
39	Bus 27	Bus 29	Line	39.5
40	Bus 27	Bus 30	Line	45
41	Bus 29	Bus 30	Line	23.3

Appendix A Table 11 %MVA by limit under contingency of branch 11

Branch no	From Name	To Name	Branch Device Type	% of MVA Limit
1	Bus 1	Bus 2	Line	72.4
2	Bus 1	Bus 3	Line	39
3	Bus 2	Bus 4	Line	52.5
4	Bus 2	Bus 5	Line	27.4
5	Bus 6	Bus 2	Line	65.1
6	Bus 3	Bus 4	Line	36.4
7	Bus 6	Bus 4	Line	41.2
8	Bus 4	Bus 12	Transformer	54.7
9	Bus 7	Bus 5	Line	32
10	Bus 6	Bus 7	Line	7.7
11	Bus 6	Bus 8	Line	0
12	Bus 6	Bus 9	Transformer	40
13	Bus 6	Bus 10	Transformer	60.9
14	Bus 6	Bus 28	Line	88.2
15	Bus 8	Bus 28	Line	75.5
16	Bus 9	Bus 10	Line	55.3
17	Bus 9	Bus 11	Line	27.8
18	Bus 10	Bus 17	Line	24.1
19	Bus 10	Bus 20	Line	32.3
20	Bus 10	Bus 21	Line	64.7
21	Bus 10	Bus 22	Line	33.6
22	Bus 13	Bus 12	Line	38.2
23	Bus 12	Bus 14	Line	28.1
24	Bus 12	Bus 15	Line	64.6
25	Bus 12	Bus 16	Line	23.6
26	Bus 14	Bus 15	Line	15.1
27	Bus 15	Bus 18	Line	35.6
28	Bus 15	Bus 23	Line	53.7
29	Bus 17	Bus 16	Line	23
30	Bus 18	Bus 19	Line	14.5
31	Bus 19	Bus 20	Line	24.5
32	Bus 21	Bus 22	Line	9.4
33	Bus 22	Bus 24	Line	85.3
34	Bus 24	Bus 23	Line	33.3
35	Bus 24	Bus 25	Line	62.6
36	Bus 25	Bus 26	Line	25.7
37	Bus 25	Bus 27	Line	45.5
38	Bus 27	Bus 28	Transformer	15.1
39	Bus 27	Bus 29	Line	39.5
40	Bus 27	Bus 30	Line	45.1
41	Bus 29	Bus 30	Line	23.3

Appendix A Table 12 %MVA by limit under contingency of branch 12

Branch no	From Name	To Name	Branch Device Type	% of MVA Limit
1	Bus 1	Bus 2	Line	71.6
2	Bus 1	Bus 3	Line	39.1
3	Bus 2	Bus 4	Line	52.3
4	Bus 2	Bus 5	Line	26.7
5	Bus 6	Bus 2	Line	63.2
6	Bus 3	Bus 4	Line	36.8
7	Bus 6	Bus 4	Line	37.4
8	Bus 4	Bus 12	Transformer	63.2
9	Bus 7	Bus 5	Line	26.4
10	Bus 6	Bus 7	Line	6.7
11	Bus 6	Bus 8	Line	132.4
12	Bus 6	Bus 9	Transformer	0
13	Bus 6	Bus 10	Transformer	85.4
14	Bus 6	Bus 28	Line	21
15	Bus 8	Bus 28	Line	39.4
16	Bus 9	Bus 10	Line	24
17	Bus 9	Bus 11	Line	24.6
18	Bus 10	Bus 17	Line	21.8
19	Bus 10	Bus 20	Line	25.5
20	Bus 10	Bus 21	Line	46.3
21	Bus 10	Bus 22	Line	21.8
22	Bus 13	Bus 12	Line	35.4
23	Bus 12	Bus 14	Line	28.9
24	Bus 12	Bus 15	Line	67.3
25	Bus 12	Bus 16	Line	36.4
26	Bus 14	Bus 15	Line	16.8
27	Bus 15	Bus 18	Line	53.1
28	Bus 15	Bus 23	Line	43.2
29	Bus 17	Bus 16	Line	50.1
30	Bus 18	Bus 19	Line	32.6
31	Bus 19	Bus 20	Line	18.3
32	Bus 21	Bus 22	Line	13.5
33	Bus 22	Bus 24	Line	37.2
34	Bus 24	Bus 23	Line	21.9
35	Bus 24	Bus 25	Line	27.8
36	Bus 25	Bus 26	Line	25.7
37	Bus 25	Bus 27	Line	37.1
38	Bus 27	Bus 28	Transformer	29.4
39	Bus 27	Bus 29	Line	39.5
40	Bus 27	Bus 30	Line	45
41	Bus 29	Bus 30	Line	23.3

Appendix A Table 13 %MVA by limit under contingency of branch 13

Branch no	From Name	To Name	Branch Device Type	% of MVA Limit
1	Bus 1	Bus 2	Line	71.7
2	Bus 1	Bus 3	Line	39.1
3	Bus 2	Bus 4	Line	51.9
4	Bus 2	Bus 5	Line	26.9
5	Bus 6	Bus 2	Line	64.3
6	Bus 3	Bus 4	Line	36.9
7	Bus 6	Bus 4	Line	42.7
8	Bus 4	Bus 12	Transformer	57.3
9	Bus 7	Bus 5	Line	24.9
10	Bus 6	Bus 7	Line	6.6
11	Bus 6	Bus 8	Line	130.2
12	Bus 6	Bus 9	Transformer	44.9
13	Bus 6	Bus 10	Transformer	0
14	Bus 6	Bus 28	Line	19.9
15	Bus 8	Bus 28	Line	37.5
16	Bus 9	Bus 10	Line	64.9
17	Bus 9	Bus 11	Line	29.1
18	Bus 10	Bus 17	Line	16.7
19	Bus 10	Bus 20	Line	26.3
20	Bus 10	Bus 21	Line	48.4
21	Bus 10	Bus 22	Line	22.9
22	Bus 13	Bus 12	Line	38.3
23	Bus 12	Bus 14	Line	28
24	Bus 12	Bus 15	Line	64.9
25	Bus 12	Bus 16	Line	31.9
26	Bus 14	Bus 15	Line	15.2
27	Bus 15	Bus 18	Line	47.7
28	Bus 15	Bus 23	Line	41.6
29	Bus 17	Bus 16	Line	38.4
30	Bus 18	Bus 19	Line	26.2
31	Bus 19	Bus 20	Line	18.7
32	Bus 21	Bus 22	Line	8.5
33	Bus 22	Bus 24	Line	34.4
34	Bus 24	Bus 23	Line	19.1
35	Bus 24	Bus 25	Line	16.3
36	Bus 25	Bus 26	Line	25.7
37	Bus 25	Bus 27	Line	28.3
38	Bus 27	Bus 28	Transformer	27.9
39	Bus 27	Bus 29	Line	39.5
40	Bus 27	Bus 30	Line	45
41	Bus 29	Bus 30	Line	23.3

Appendix A Table 14 %MVA by limit under contingency of branch 14

Branch no	From Name	To Name	Branch Device Type	% of MVA Limit
1	Bus 1	Bus 2	Line	72.4
2	Bus 1	Bus 3	Line	38.4
3	Bus 2	Bus 4	Line	49.7
4	Bus 2	Bus 5	Line	26.6
5	Bus 6	Bus 2	Line	62.9
6	Bus 3	Bus 4	Line	36.1
7	Bus 6	Bus 4	Line	44.3
8	Bus 4	Bus 12	Transformer	49.6
9	Bus 7	Bus 5	Line	25.4
10	Bus 6	Bus 7	Line	6.8
11	Bus 6	Bus 8	Line	130.5
12	Bus 6	Bus 9	Transformer	33.9
13	Bus 6	Bus 10	Transformer	58.2
14	Bus 6	Bus 28	Line	0
15	Bus 8	Bus 28	Line	48.4
16	Bus 9	Bus 10	Line	50.7
17	Bus 9	Bus 11	Line	24.7
18	Bus 10	Bus 17	Line	25.1
19	Bus 10	Bus 20	Line	32.1
20	Bus 10	Bus 21	Line	54.9
21	Bus 10	Bus 22	Line	27.2
22	Bus 13	Bus 12	Line	35.6
23	Bus 12	Bus 14	Line	26.2
24	Bus 12	Bus 15	Line	58.7
25	Bus 12	Bus 16	Line	22.4
26	Bus 14	Bus 15	Line	11.6
27	Bus 15	Bus 18	Line	36.2
28	Bus 15	Bus 23	Line	37.7
29	Bus 17	Bus 16	Line	20.5
30	Bus 18	Bus 19	Line	15.1
31	Bus 19	Bus 20	Line	24.3
32	Bus 21	Bus 22	Line	5.8
33	Bus 22	Bus 24	Line	55.3
34	Bus 24	Bus 23	Line	15.6
35	Bus 24	Bus 25	Line	20.7
36	Bus 25	Bus 26	Line	25.7
37	Bus 25	Bus 27	Line	11.5
38	Bus 27	Bus 28	Transformer	23.5
39	Bus 27	Bus 29	Line	39.5
40	Bus 27	Bus 30	Line	45
41	Bus 29	Bus 30	Line	23.3

Appendix A Table 15 %MVA by limit under contingency of branch 15

Branch no	From Name	To Name	Branch Device Type	% of MVA Limit
1	Bus 1	Bus 2	Line	71.9
2	Bus 1	Bus 3	Line	38.9
3	Bus 2	Bus 4	Line	51.3
4	Bus 2	Bus 5	Line	27.1
5	Bus 6	Bus 2	Line	64.8
6	Bus 3	Bus 4	Line	36.6
7	Bus 6	Bus 4	Line	44.9
8	Bus 4	Bus 12	Transformer	51.2
9	Bus 7	Bus 5	Line	26.3
10	Bus 6	Bus 7	Line	6.4
11	Bus 6	Bus 8	Line	112.7
12	Bus 6	Bus 9	Transformer	35.4
13	Bus 6	Bus 10	Transformer	59.8
14	Bus 6	Bus 28	Line	40.7
15	Bus 8	Bus 28	Line	0
16	Bus 9	Bus 10	Line	52.2
17	Bus 9	Bus 11	Line	25.1
18	Bus 10	Bus 17	Line	24.7
19	Bus 10	Bus 20	Line	32.2
20	Bus 10	Bus 21	Line	58.2
21	Bus 10	Bus 22	Line	29.4
22	Bus 13	Bus 12	Line	36.1
23	Bus 12	Bus 14	Line	26.8
24	Bus 12	Bus 15	Line	60.9
25	Bus 12	Bus 16	Line	22.9
26	Bus 14	Bus 15	Line	12.8
27	Bus 15	Bus 18	Line	36.1
28	Bus 15	Bus 23	Line	43.2
29	Bus 17	Bus 16	Line	21.6
30	Bus 18	Bus 19	Line	15
31	Bus 19	Bus 20	Line	24.4
32	Bus 21	Bus 22	Line	6.2
33	Bus 22	Bus 24	Line	65.5
34	Bus 24	Bus 23	Line	21.1
35	Bus 24	Bus 25	Line	32.6
36	Bus 25	Bus 26	Line	25.7
37	Bus 25	Bus 27	Line	6.2
38	Bus 27	Bus 28	Transformer	19.6
39	Bus 27	Bus 29	Line	39.5
40	Bus 27	Bus 30	Line	45.1
41	Bus 29	Bus 30	Line	23.3

Appendix A Table 16 %MVA by limit under contingency of branch 16

Branch no	From Name	To Name	Branch Device Type	% of MVA Limit
1	Bus 1	Bus 2	Line	71.5
2	Bus 1	Bus 3	Line	39.1
3	Bus 2	Bus 4	Line	52.5
4	Bus 2	Bus 5	Line	26.4
5	Bus 6	Bus 2	Line	61.6
6	Bus 3	Bus 4	Line	36.7
7	Bus 6	Bus 4	Line	32.8
8	Bus 4	Bus 12	Transformer	70.9
9	Bus 7	Bus 5	Line	26.3
10	Bus 6	Bus 7	Line	7.1
11	Bus 6	Bus 8	Line	130.3
12	Bus 6	Bus 9	Transformer	19.8
13	Bus 6	Bus 10	Transformer	103.7
14	Bus 6	Bus 28	Line	22.4
15	Bus 8	Bus 28	Line	44.8
16	Bus 9	Bus 10	Line	0
17	Bus 9	Bus 11	Line	20.2
18	Bus 10	Bus 17	Line	12
19	Bus 10	Bus 20	Line	18
20	Bus 10	Bus 21	Line	40.3
21	Bus 10	Bus 22	Line	17.7
22	Bus 13	Bus 12	Line	43
23	Bus 12	Bus 14	Line	31.2
24	Bus 12	Bus 15	Line	75.4
25	Bus 12	Bus 16	Line	46.6
26	Bus 14	Bus 15	Line	21.4
27	Bus 15	Bus 18	Line	65.1
28	Bus 15	Bus 23	Line	50.1
29	Bus 17	Bus 16	Line	66.9
30	Bus 18	Bus 19	Line	43.2
31	Bus 19	Bus 20	Line	10.8
32	Bus 21	Bus 22	Line	16.1
33	Bus 22	Bus 24	Line	17.5
34	Bus 24	Bus 23	Line	27.4
35	Bus 24	Bus 25	Line	30.6
36	Bus 25	Bus 26	Line	25.7
37	Bus 25	Bus 27	Line	47.8
38	Bus 27	Bus 28	Transformer	32.7
39	Bus 27	Bus 29	Line	39.5
40	Bus 27	Bus 30	Line	45.1
41	Bus 29	Bus 30	Line	23.3

Appendix A Table 17 %MVA by limit under contingency of branch 17

Branch no	From Name	To Name	Branch Device Type	% of MVA Limit
1	Bus 1	Bus 2	Line	77.7
2	Bus 1	Bus 3	Line	41.5
3	Bus 2	Bus 4	Line	55
4	Bus 2	Bus 5	Line	28.4
5	Bus 6	Bus 2	Line	69.7
6	Bus 3	Bus 4	Line	39
7	Bus 6	Bus 4	Line	48.4
8	Bus 4	Bus 12	Transformer	53.3
9	Bus 7	Bus 5	Line	31
10	Bus 6	Bus 7	Line	5.8
11	Bus 6	Bus 8	Line	128.3
12	Bus 6	Bus 9	Transformer	41.9
13	Bus 6	Bus 10	Transformer	64
14	Bus 6	Bus 28	Line	18.7
15	Bus 8	Bus 28	Line	34.6
16	Bus 9	Bus 10	Line	41.5
17	Bus 9	Bus 11	Line	0
18	Bus 10	Bus 17	Line	18.6
19	Bus 10	Bus 20	Line	28.5
20	Bus 10	Bus 21	Line	51.3
21	Bus 10	Bus 22	Line	24.8
22	Bus 13	Bus 12	Line	41.3
23	Bus 12	Bus 14	Line	27.3
24	Bus 12	Bus 15	Line	62.7
25	Bus 12	Bus 16	Line	28.2
26	Bus 14	Bus 15	Line	14
27	Bus 15	Bus 18	Line	43
28	Bus 15	Bus 23	Line	40.6
29	Bus 17	Bus 16	Line	30.9
30	Bus 18	Bus 19	Line	21.7
31	Bus 19	Bus 20	Line	20.8
32	Bus 21	Bus 22	Line	5.8
33	Bus 22	Bus 24	Line	42.7
34	Bus 24	Bus 23	Line	17.9
35	Bus 24	Bus 25	Line	15.7
36	Bus 25	Bus 26	Line	25.7
37	Bus 25	Bus 27	Line	20.4
38	Bus 27	Bus 28	Transformer	25.9
39	Bus 27	Bus 29	Line	39.5
40	Bus 27	Bus 30	Line	45.1
41	Bus 29	Bus 30	Line	23.3

Appendix A Table 18 %MVA by limit under contingency of branch 18

Branch no	From Name	To Name	Branch Device Type	% of MVA Limit
1	Bus 1	Bus 2	Line	71.8
2	Bus 1	Bus 3	Line	39
3	Bus 2	Bus 4	Line	51.6
4	Bus 2	Bus 5	Line	27
5	Bus 6	Bus 2	Line	64.7
6	Bus 3	Bus 4	Line	36.7
7	Bus 6	Bus 4	Line	44.7
8	Bus 4	Bus 12	Transformer	53.2
9	Bus 7	Bus 5	Line	25.7
10	Bus 6	Bus 7	Line	6.4
11	Bus 6	Bus 8	Line	127.6
12	Bus 6	Bus 9	Transformer	31.7
13	Bus 6	Bus 10	Transformer	53.1
14	Bus 6	Bus 28	Line	17.9
15	Bus 8	Bus 28	Line	32.3
16	Bus 9	Bus 10	Line	46.9
17	Bus 9	Bus 11	Line	22.5
18	Bus 10	Bus 17	Line	0
19	Bus 10	Bus 20	Line	38.2
20	Bus 10	Bus 21	Line	57.4
21	Bus 10	Bus 22	Line	28.8
22	Bus 13	Bus 12	Line	40.4
23	Bus 12	Bus 14	Line	23.3
24	Bus 12	Bus 15	Line	49.4
25	Bus 12	Bus 16	Line	47.9
26	Bus 14	Bus 15	Line	6
27	Bus 15	Bus 18	Line	24.4
28	Bus 15	Bus 23	Line	26.1
29	Bus 17	Bus 16	Line	68.4
30	Bus 18	Bus 19	Line	4.2
31	Bus 19	Bus 20	Line	30.2
32	Bus 21	Bus 22	Line	7
33	Bus 22	Bus 24	Line	63.5
34	Bus 24	Bus 23	Line	4.7
35	Bus 24	Bus 25	Line	19.8
36	Bus 25	Bus 26	Line	25.7
37	Bus 25	Bus 27	Line	15.7
38	Bus 27	Bus 28	Transformer	24.4
39	Bus 27	Bus 29	Line	39.5
40	Bus 27	Bus 30	Line	45
41	Bus 29	Bus 30	Line	23.3

Appendix A Table 19 %MVA by limit under contingency of branch 19

Branch no	From Name	To Name	Branch Device Type	% of MVA Limit
1	Bus 1	Bus 2	Line	72
2	Bus 1	Bus 3	Line	39.1
3	Bus 2	Bus 4	Line	51.8
4	Bus 2	Bus 5	Line	27
5	Bus 6	Bus 2	Line	64.8
6	Bus 3	Bus 4	Line	36.8
7	Bus 6	Bus 4	Line	44.1
8	Bus 4	Bus 12	Transformer	54.2
9	Bus 7	Bus 5	Line	25.9
10	Bus 6	Bus 7	Line	6.4
11	Bus 6	Bus 8	Line	127.7
12	Bus 6	Bus 9	Transformer	30.9
13	Bus 6	Bus 10	Transformer	53
14	Bus 6	Bus 28	Line	18.2
15	Bus 8	Bus 28	Line	33.1
16	Bus 9	Bus 10	Line	46.6
17	Bus 9	Bus 11	Line	23.2
18	Bus 10	Bus 17	Line	34.3
19	Bus 10	Bus 20	Line	0
20	Bus 10	Bus 21	Line	60
21	Bus 10	Bus 22	Line	30.5
22	Bus 13	Bus 12	Line	39.7
23	Bus 12	Bus 14	Line	31.5
24	Bus 12	Bus 15	Line	76.8
25	Bus 12	Bus 16	Line	11.8
26	Bus 14	Bus 15	Line	22.3
27	Bus 15	Bus 18	Line	102.8
28	Bus 15	Bus 23	Line	15.9
29	Bus 17	Bus 16	Line	1.1
30	Bus 18	Bus 19	Line	78.7
31	Bus 19	Bus 20	Line	7.2
32	Bus 21	Bus 22	Line	8
33	Bus 22	Bus 24	Line	71.7
34	Bus 24	Bus 23	Line	6.5
35	Bus 24	Bus 25	Line	17.6
36	Bus 25	Bus 26	Line	25.7
37	Bus 25	Bus 27	Line	17
38	Bus 27	Bus 28	Transformer	25
39	Bus 27	Bus 29	Line	39.5
40	Bus 27	Bus 30	Line	45
41	Bus 29	Bus 30	Line	23.3

Appendix A Table 20 %MVA by limit under contingency of branch 20

Branch no	From Name	To Name	Branch Device Type	% of MVA Limit
1	Bus 1	Bus 2	Line	72
2	Bus 1	Bus 3	Line	38.9
3	Bus 2	Bus 4	Line	51.3
4	Bus 2	Bus 5	Line	27.1
5	Bus 6	Bus 2	Line	65.1
6	Bus 3	Bus 4	Line	36.6
7	Bus 6	Bus 4	Line	45.8
8	Bus 4	Bus 12	Transformer	50
9	Bus 7	Bus 5	Line	26.3
10	Bus 6	Bus 7	Line	6.3
11	Bus 6	Bus 8	Line	128.9
12	Bus 6	Bus 9	Transformer	32.1
13	Bus 6	Bus 10	Transformer	55.8
14	Bus 6	Bus 28	Line	19.1
15	Bus 8	Bus 28	Line	35.7
16	Bus 9	Bus 10	Line	48.7
17	Bus 9	Bus 11	Line	24.7
18	Bus 10	Bus 17	Line	26.7
19	Bus 10	Bus 20	Line	34.3
20	Bus 10	Bus 21	Line	0
21	Bus 10	Bus 22	Line	71.2
22	Bus 13	Bus 12	Line	36.4
23	Bus 12	Bus 14	Line	27
24	Bus 12	Bus 15	Line	61.6
25	Bus 12	Bus 16	Line	20.1
26	Bus 14	Bus 15	Line	13.2
27	Bus 15	Bus 18	Line	31.6
28	Bus 15	Bus 23	Line	49.3
29	Bus 17	Bus 16	Line	15.7
30	Bus 18	Bus 19	Line	10.5
31	Bus 19	Bus 20	Line	26.5
32	Bus 21	Bus 22	Line	54.9
33	Bus 22	Bus 24	Line	31.7
34	Bus 24	Bus 23	Line	27
35	Bus 24	Bus 25	Line	15
36	Bus 25	Bus 26	Line	25.7
37	Bus 25	Bus 27	Line	23.3
38	Bus 27	Bus 28	Transformer	26.7
39	Bus 27	Bus 29	Line	39.5
40	Bus 27	Bus 30	Line	45
41	Bus 29	Bus 30	Line	23.3

Appendix A Table 21 %MVA by limit under contingency of branch 21

Branch no	From Name	To Name	Branch Device Type	% of MVA Limit
1	Bus 1	Bus 2	Line	72
2	Bus 1	Bus 3	Line	38.8
3	Bus 2	Bus 4	Line	51.2
4	Bus 2	Bus 5	Line	27.1
5	Bus 6	Bus 2	Line	65
6	Bus 3	Bus 4	Line	36.6
7	Bus 6	Bus 4	Line	46
8	Bus 4	Bus 12	Transformer	49.5
9	Bus 7	Bus 5	Line	26.2
10	Bus 6	Bus 7	Line	6.3
11	Bus 6	Bus 8	Line	128.1
12	Bus 6	Bus 9	Transformer	32.8
13	Bus 6	Bus 10	Transformer	56.8
14	Bus 6	Bus 28	Line	18.4
15	Bus 8	Bus 28	Line	33.8
16	Bus 9	Bus 10	Line	49.5
17	Bus 9	Bus 11	Line	24.7
18	Bus 10	Bus 17	Line	25.7
19	Bus 10	Bus 20	Line	32.8
20	Bus 10	Bus 21	Line	77
21	Bus 10	Bus 22	Line	0
22	Bus 13	Bus 12	Line	35.9
23	Bus 12	Bus 14	Line	26.3
24	Bus 12	Bus 15	Line	59.3
25	Bus 12	Bus 16	Line	21.6
26	Bus 14	Bus 15	Line	11.9
27	Bus 15	Bus 18	Line	34.7
28	Bus 15	Bus 23	Line	40.6
29	Bus 17	Bus 16	Line	18.8
30	Bus 18	Bus 19	Line	13.7
31	Bus 19	Bus 20	Line	25
32	Bus 21	Bus 22	Line	22.4
33	Bus 22	Bus 24	Line	45
34	Bus 24	Bus 23	Line	18.4
35	Bus 24	Bus 25	Line	16.9
36	Bus 25	Bus 26	Line	25.7
37	Bus 25	Bus 27	Line	18.7
38	Bus 27	Bus 28	Transformer	25.4
39	Bus 27	Bus 29	Line	39.5
40	Bus 27	Bus 30	Line	45
41	Bus 29	Bus 30	Line	23.3

Appendix A Table 22 %MVA by limit under contingency of branch 22

Branch no	From Name	To Name	Branch Device Type	% of MVA Limit
1	Bus 1	Bus 2	Line	78.9
2	Bus 1	Bus 3	Line	42.1
3	Bus 2	Bus 4	Line	56.7
4	Bus 2	Bus 5	Line	28.6
5	Bus 6	Bus 2	Line	70.4
6	Bus 3	Bus 4	Line	39.3
7	Bus 6	Bus 4	Line	49.2
8	Bus 4	Bus 12	Transformer	61
9	Bus 7	Bus 5	Line	32.3
10	Bus 6	Bus 7	Line	6.1
11	Bus 6	Bus 8	Line	128.4
12	Bus 6	Bus 9	Transformer	38.2
13	Bus 6	Bus 10	Transformer	65.6
14	Bus 6	Bus 28	Line	19.2
15	Bus 8	Bus 28	Line	36.4
16	Bus 9	Bus 10	Line	58.3
17	Bus 9	Bus 11	Line	32.4
18	Bus 10	Bus 17	Line	39.6
19	Bus 10	Bus 20	Line	39.8
20	Bus 10	Bus 21	Line	55.6
21	Bus 10	Bus 22	Line	27.7
22	Bus 13	Bus 12	Line	0
23	Bus 12	Bus 14	Line	22.9
24	Bus 12	Bus 15	Line	47.3
25	Bus 12	Bus 16	Line	13.3
26	Bus 14	Bus 15	Line	5.8
27	Bus 15	Bus 18	Line	25.3
28	Bus 15	Bus 23	Line	22.1
29	Bus 17	Bus 16	Line	21.2
30	Bus 18	Bus 19	Line	11.1
31	Bus 19	Bus 20	Line	31.7
32	Bus 21	Bus 22	Line	8
33	Bus 22	Bus 24	Line	59.2
34	Bus 24	Bus 23	Line	11.2
35	Bus 24	Bus 25	Line	12.3
36	Bus 25	Bus 26	Line	25.7
37	Bus 25	Bus 27	Line	23.8
38	Bus 27	Bus 28	Transformer	27
39	Bus 27	Bus 29	Line	39.5
40	Bus 27	Bus 30	Line	45.1
41	Bus 29	Bus 30	Line	23.3

Appendix A Table 23 %MVA by limit under contingency of branch 23

Branch no	From Name	To Name	Branch Device Type	% of MVA Limit
1	Bus 1	Bus 2	Line	72
2	Bus 1	Bus 3	Line	38.8
3	Bus 2	Bus 4	Line	51.1
4	Bus 2	Bus 5	Line	27.2
5	Bus 6	Bus 2	Line	65.2
6	Bus 3	Bus 4	Line	36.6
7	Bus 6	Bus 4	Line	46.7
8	Bus 4	Bus 12	Transformer	48.2
9	Bus 7	Bus 5	Line	26.4
10	Bus 6	Bus 7	Line	6.3
11	Bus 6	Bus 8	Line	127.8
12	Bus 6	Bus 9	Transformer	33.8
13	Bus 6	Bus 10	Transformer	58.4
14	Bus 6	Bus 28	Line	18.3
15	Bus 8	Bus 28	Line	33.5
16	Bus 9	Bus 10	Line	50.9
17	Bus 9	Bus 11	Line	25.3
18	Bus 10	Bus 17	Line	23.4
19	Bus 10	Bus 20	Line	34.8
20	Bus 10	Bus 21	Line	54.9
21	Bus 10	Bus 22	Line	27.2
22	Bus 13	Bus 12	Line	35.3
23	Bus 12	Bus 14	Line	0
24	Bus 12	Bus 15	Line	79.4
25	Bus 12	Bus 16	Line	24.7
26	Bus 14	Bus 15	Line	40.2
27	Bus 15	Bus 18	Line	31
28	Bus 15	Bus 23	Line	30.7
29	Bus 17	Bus 16	Line	25.2
30	Bus 18	Bus 19	Line	10.3
31	Bus 19	Bus 20	Line	26.9
32	Bus 21	Bus 22	Line	6.2
33	Bus 22	Bus 24	Line	55.6
34	Bus 24	Bus 23	Line	9.2
35	Bus 24	Bus 25	Line	17
36	Bus 25	Bus 26	Line	25.7
37	Bus 25	Bus 27	Line	17.8
38	Bus 27	Bus 28	Transformer	25.2
39	Bus 27	Bus 29	Line	39.5
40	Bus 27	Bus 30	Line	45
41	Bus 29	Bus 30	Line	23.3

Appendix A Table 24 %MVA by limit under contingency of branch 24

Branch no	From Name	To Name	Branch Device Type	% of MVA Limit
1	Bus 1	Bus 2	Line	72.3
2	Bus 1	Bus 3	Line	38.7
3	Bus 2	Bus 4	Line	50.7
4	Bus 2	Bus 5	Line	27.3
5	Bus 6	Bus 2	Line	65.8
6	Bus 3	Bus 4	Line	36.5
7	Bus 6	Bus 4	Line	49.6
8	Bus 4	Bus 12	Transformer	43
9	Bus 7	Bus 5	Line	27
10	Bus 6	Bus 7	Line	6.1
11	Bus 6	Bus 8	Line	129
12	Bus 6	Bus 9	Transformer	36.3
13	Bus 6	Bus 10	Transformer	62
14	Bus 6	Bus 28	Line	19.2
15	Bus 8	Bus 28	Line	36.1
16	Bus 9	Bus 10	Line	54
17	Bus 9	Bus 11	Line	26.7
18	Bus 10	Bus 17	Line	19.3
19	Bus 10	Bus 20	Line	45.8
20	Bus 10	Bus 21	Line	59.4
21	Bus 10	Bus 22	Line	30.1
22	Bus 13	Bus 12	Line	34
23	Bus 12	Bus 14	Line	58.9
24	Bus 12	Bus 15	Line	0
25	Bus 12	Bus 16	Line	34.1
26	Bus 14	Bus 15	Line	73.3
27	Bus 15	Bus 18	Line	9.8
28	Bus 15	Bus 23	Line	10.4
29	Bus 17	Bus 16	Line	44.4
30	Bus 18	Bus 19	Line	11.2
31	Bus 19	Bus 20	Line	37.4
32	Bus 21	Bus 22	Line	7.6
33	Bus 22	Bus 24	Line	69.6
34	Bus 24	Bus 23	Line	12.1
35	Bus 24	Bus 25	Line	14.6
36	Bus 25	Bus 26	Line	25.7
37	Bus 25	Bus 27	Line	24
38	Bus 27	Bus 28	Transformer	26.9
39	Bus 27	Bus 29	Line	39.5
40	Bus 27	Bus 30	Line	45
41	Bus 29	Bus 30	Line	23.3

Appendix A Table 25 %MVA by limit under contingency of branch 25

Branch no	From Name	To Name	Branch Device Type	% of MVA Limit
1	Bus 1	Bus 2	Line	72.1
2	Bus 1	Bus 3	Line	38.7
3	Bus 2	Bus 4	Line	50.7
4	Bus 2	Bus 5	Line	27.3
5	Bus 6	Bus 2	Line	65.5
6	Bus 3	Bus 4	Line	36.4
7	Bus 6	Bus 4	Line	48.7
8	Bus 4	Bus 12	Transformer	44.4
9	Bus 7	Bus 5	Line	26.7
10	Bus 6	Bus 7	Line	6.2
11	Bus 6	Bus 8	Line	127.9
12	Bus 6	Bus 9	Transformer	36.1
13	Bus 6	Bus 10	Transformer	61.8
14	Bus 6	Bus 28	Line	18.3
15	Bus 8	Bus 28	Line	33.4
16	Bus 9	Bus 10	Line	53.8
17	Bus 9	Bus 11	Line	26.4
18	Bus 10	Bus 17	Line	46.3
19	Bus 10	Bus 20	Line	26.6
20	Bus 10	Bus 21	Line	50.5
21	Bus 10	Bus 22	Line	24.3
22	Bus 13	Bus 12	Line	33.6
23	Bus 12	Bus 14	Line	28.6
24	Bus 12	Bus 15	Line	66.5
25	Bus 12	Bus 16	Line	0
26	Bus 14	Bus 15	Line	16.2
27	Bus 15	Bus 18	Line	48.2
28	Bus 15	Bus 23	Line	45.4
29	Bus 17	Bus 16	Line	24.8
30	Bus 18	Bus 19	Line	27.1
31	Bus 19	Bus 20	Line	19.1
32	Bus 21	Bus 22	Line	8
33	Bus 22	Bus 24	Line	42.2
34	Bus 24	Bus 23	Line	23.7
35	Bus 24	Bus 25	Line	17.5
36	Bus 25	Bus 26	Line	25.7
37	Bus 25	Bus 27	Line	17.7
38	Bus 27	Bus 28	Transformer	25.1
39	Bus 27	Bus 29	Line	39.5
40	Bus 27	Bus 30	Line	45
41	Bus 29	Bus 30	Line	23.3

Appendix A Table 26 %MVA by limit under contingency of branch 26

Branch no	From Name	To Name	Branch Device Type	% of MVA Limit
1	Bus 1	Bus 2	Line	72
2	Bus 1	Bus 3	Line	38.8
3	Bus 2	Bus 4	Line	51.1
4	Bus 2	Bus 5	Line	27.1
5	Bus 6	Bus 2	Line	65
6	Bus 3	Bus 4	Line	36.6
7	Bus 6	Bus 4	Line	46.2
8	Bus 4	Bus 12	Transformer	49
9	Bus 7	Bus 5	Line	26.2
10	Bus 6	Bus 7	Line	6.3
11	Bus 6	Bus 8	Line	127.7
12	Bus 6	Bus 9	Transformer	33.4
13	Bus 6	Bus 10	Transformer	57.6
14	Bus 6	Bus 28	Line	18.1
15	Bus 8	Bus 28	Line	33
16	Bus 9	Bus 10	Line	50.2
17	Bus 9	Bus 11	Line	24.9
18	Bus 10	Bus 17	Line	24.6
19	Bus 10	Bus 20	Line	32.6
20	Bus 10	Bus 21	Line	54.1
21	Bus 10	Bus 22	Line	26.6
22	Bus 13	Bus 12	Line	35.5
23	Bus 12	Bus 14	Line	20.3
24	Bus 12	Bus 15	Line	62.8
25	Bus 12	Bus 16	Line	23
26	Bus 14	Bus 15	Line	0
27	Bus 15	Bus 18	Line	35.3
28	Bus 15	Bus 23	Line	35
29	Bus 17	Bus 16	Line	21.6
30	Bus 18	Bus 19	Line	14.3
31	Bus 19	Bus 20	Line	24.8
32	Bus 21	Bus 22	Line	6.1
33	Bus 22	Bus 24	Line	52.7
34	Bus 24	Bus 23	Line	13
35	Bus 24	Bus 25	Line	18
36	Bus 25	Bus 26	Line	25.7
37	Bus 25	Bus 27	Line	16.8
38	Bus 27	Bus 28	Transformer	24.9
39	Bus 27	Bus 29	Line	39.5
40	Bus 27	Bus 30	Line	45
41	Bus 29	Bus 30	Line	23.3

Appendix A Table 27 %MVA by limit under contingency of branch 27

Branch no	From Name	To Name	Branch Device Type	% of MVA Limit
1	Bus 1	Bus 2	Line	72
2	Bus 1	Bus 3	Line	38.8
3	Bus 2	Bus 4	Line	50.9
4	Bus 2	Bus 5	Line	27.2
5	Bus 6	Bus 2	Line	65.3
6	Bus 3	Bus 4	Line	36.5
7	Bus 6	Bus 4	Line	47.6
8	Bus 4	Bus 12	Transformer	46.5
9	Bus 7	Bus 5	Line	26.5
10	Bus 6	Bus 7	Line	6.2
11	Bus 6	Bus 8	Line	127.6
12	Bus 6	Bus 9	Transformer	35.1
13	Bus 6	Bus 10	Transformer	60.3
14	Bus 6	Bus 28	Line	18.1
15	Bus 8	Bus 28	Line	32.8
16	Bus 9	Bus 10	Line	52.5
17	Bus 9	Bus 11	Line	25.9
18	Bus 10	Bus 17	Line	21
19	Bus 10	Bus 20	Line	50.9
20	Bus 10	Bus 21	Line	50.3
21	Bus 10	Bus 22	Line	24.2
22	Bus 13	Bus 12	Line	34.5
23	Bus 12	Bus 14	Line	23
24	Bus 12	Bus 15	Line	48.3
25	Bus 12	Bus 16	Line	28.7
26	Bus 14	Bus 15	Line	5.4
27	Bus 15	Bus 18	Line	0
28	Bus 15	Bus 23	Line	47.6
29	Bus 17	Bus 16	Line	33.2
30	Bus 18	Bus 19	Line	20.9
31	Bus 19	Bus 20	Line	42.3
32	Bus 21	Bus 22	Line	7.8
33	Bus 22	Bus 24	Line	41.4
34	Bus 24	Bus 23	Line	25.6
35	Bus 24	Bus 25	Line	18.4
36	Bus 25	Bus 26	Line	25.7
37	Bus 25	Bus 27	Line	16.4
38	Bus 27	Bus 28	Transformer	24.8
39	Bus 27	Bus 29	Line	39.5
40	Bus 27	Bus 30	Line	45
41	Bus 29	Bus 30	Line	23.3

Appendix A Table 28 %MVA by limit under contingency of branch 28

Branch no	From Name	To Name	Branch Device Type	% of MVA Limit
1	Bus 1	Bus 2	Line	72
2	Bus 1	Bus 3	Line	38.8
3	Bus 2	Bus 4	Line	50.9
4	Bus 2	Bus 5	Line	27.2
5	Bus 6	Bus 2	Line	65.3
6	Bus 3	Bus 4	Line	36.5
7	Bus 6	Bus 4	Line	47.6
8	Bus 4	Bus 12	Transformer	46.3
9	Bus 7	Bus 5	Line	26.6
10	Bus 6	Bus 7	Line	6.2
11	Bus 6	Bus 8	Line	128.6
12	Bus 6	Bus 9	Transformer	34.1
13	Bus 6	Bus 10	Transformer	58.9
14	Bus 6	Bus 28	Line	19.1
15	Bus 8	Bus 28	Line	36
16	Bus 9	Bus 10	Line	51.3
17	Bus 9	Bus 11	Line	25.7
18	Bus 10	Bus 17	Line	21.4
19	Bus 10	Bus 20	Line	26.2
20	Bus 10	Bus 21	Line	62.7
21	Bus 10	Bus 22	Line	32.3
22	Bus 13	Bus 12	Line	34.2
23	Bus 12	Bus 14	Line	23.1
24	Bus 12	Bus 15	Line	48.6
25	Bus 12	Bus 16	Line	27.7
26	Bus 14	Bus 15	Line	5.5
27	Bus 15	Bus 18	Line	48.3
28	Bus 15	Bus 23	Line	0
29	Bus 17	Bus 16	Line	31.1
30	Bus 18	Bus 19	Line	27
31	Bus 19	Bus 20	Line	18.6
32	Bus 21	Bus 22	Line	10.4
33	Bus 22	Bus 24	Line	80.7
34	Bus 24	Bus 23	Line	22.6
35	Bus 24	Bus 25	Line	13.3
36	Bus 25	Bus 26	Line	25.7
37	Bus 25	Bus 27	Line	23.3
38	Bus 27	Bus 28	Transformer	26.8
39	Bus 27	Bus 29	Line	39.5
40	Bus 27	Bus 30	Line	45
41	Bus 29	Bus 30	Line	23.3

Appendix A Table 29 %MVA by limit under contingency of branch 29

Branch no	From Name	To Name	Branch Device Type	% of MVA Limit
1	Bus 1	Bus 2	Line	72.1
2	Bus 1	Bus 3	Line	38.7
3	Bus 2	Bus 4	Line	50.8
4	Bus 2	Bus 5	Line	27.2
5	Bus 6	Bus 2	Line	65.2
6	Bus 3	Bus 4	Line	36.5
7	Bus 6	Bus 4	Line	47.5
8	Bus 4	Bus 12	Transformer	46.7
9	Bus 7	Bus 5	Line	26.3
10	Bus 6	Bus 7	Line	6.3
11	Bus 6	Bus 8	Line	127.8
12	Bus 6	Bus 9	Transformer	34.7
13	Bus 6	Bus 10	Transformer	59.3
14	Bus 6	Bus 28	Line	18.2
15	Bus 8	Bus 28	Line	33
16	Bus 9	Bus 10	Line	51.7
17	Bus 9	Bus 11	Line	25.3
18	Bus 10	Bus 17	Line	33.6
19	Bus 10	Bus 20	Line	29.6
20	Bus 10	Bus 21	Line	52.3
21	Bus 10	Bus 22	Line	25.5
22	Bus 13	Bus 12	Line	34.9
23	Bus 12	Bus 14	Line	27.1
24	Bus 12	Bus 15	Line	61.7
25	Bus 12	Bus 16	Line	12.3
26	Bus 14	Bus 15	Line	13.3
27	Bus 15	Bus 18	Line	41.8
28	Bus 15	Bus 23	Line	40.1
29	Bus 17	Bus 16	Line	0
30	Bus 18	Bus 19	Line	20.8
31	Bus 19	Bus 20	Line	21.9
32	Bus 21	Bus 22	Line	7
33	Bus 22	Bus 24	Line	47.7
34	Bus 24	Bus 23	Line	18.6
35	Bus 24	Bus 25	Line	18.2
36	Bus 25	Bus 26	Line	25.7
37	Bus 25	Bus 27	Line	17
38	Bus 27	Bus 28	Transformer	24.9
39	Bus 27	Bus 29	Line	39.5
40	Bus 27	Bus 30	Line	45
41	Bus 29	Bus 30	Line	23.3

Appendix A Table 30 %MVA by limit under contingency of branch 30

Branch no	From Name	To Name	Branch Device Type	% of MVA Limit
1	Bus 1	Bus 2	Line	72
2	Bus 1	Bus 3	Line	38.8
3	Bus 2	Bus 4	Line	51
4	Bus 2	Bus 5	Line	27.1
5	Bus 6	Bus 2	Line	65.1
6	Bus 3	Bus 4	Line	36.5
7	Bus 6	Bus 4	Line	46.8
8	Bus 4	Bus 12	Transformer	48
9	Bus 7	Bus 5	Line	26.3
10	Bus 6	Bus 7	Line	6.3
11	Bus 6	Bus 8	Line	127.6
12	Bus 6	Bus 9	Transformer	34
13	Bus 6	Bus 10	Transformer	58.6
14	Bus 6	Bus 28	Line	18.1
15	Bus 8	Bus 28	Line	32.8
16	Bus 9	Bus 10	Line	51
17	Bus 9	Bus 11	Line	25.2
18	Bus 10	Bus 17	Line	23.3
19	Bus 10	Bus 20	Line	39.8
20	Bus 10	Bus 21	Line	52.3
21	Bus 10	Bus 22	Line	25.5
22	Bus 13	Bus 12	Line	35.2
23	Bus 12	Bus 14	Line	24.7
24	Bus 12	Bus 15	Line	53.9
25	Bus 12	Bus 16	Line	25
26	Bus 14	Bus 15	Line	8.7
27	Bus 15	Bus 18	Line	20.8
28	Bus 15	Bus 23	Line	40.9
29	Bus 17	Bus 16	Line	25.9
30	Bus 18	Bus 19	Line	0
31	Bus 19	Bus 20	Line	31.7
32	Bus 21	Bus 22	Line	6.7
33	Bus 22	Bus 24	Line	47.5
34	Bus 24	Bus 23	Line	19
35	Bus 24	Bus 25	Line	18.4
36	Bus 25	Bus 26	Line	25.7
37	Bus 25	Bus 27	Line	16.4
38	Bus 27	Bus 28	Transformer	24.8
39	Bus 27	Bus 29	Line	39.5
40	Bus 27	Bus 30	Line	45
41	Bus 29	Bus 30	Line	23.3

Appendix A Table 31 %MVA by limit under contingency of branch 31

Branch no	From Name	To Name	Branch Device Type	% of MVA Limit
1	Bus 1	Bus 2	Line	71.9
2	Bus 1	Bus 3	Line	39
3	Bus 2	Bus 4	Line	51.6
4	Bus 2	Bus 5	Line	27
5	Bus 6	Bus 2	Line	64.8
6	Bus 3	Bus 4	Line	36.7
7	Bus 6	Bus 4	Line	44.6
8	Bus 4	Bus 12	Transformer	52.9
9	Bus 7	Bus 5	Line	25.9
10	Bus 6	Bus 7	Line	6.4
11	Bus 6	Bus 8	Line	127.7
12	Bus 6	Bus 9	Transformer	31.5
13	Bus 6	Bus 10	Transformer	54
14	Bus 6	Bus 28	Line	18.2
15	Bus 8	Bus 28	Line	33
16	Bus 9	Bus 10	Line	47.3
17	Bus 9	Bus 11	Line	23.5
18	Bus 10	Bus 17	Line	32.1
19	Bus 10	Bus 20	Line	7.2
20	Bus 10	Bus 21	Line	58.6
21	Bus 10	Bus 22	Line	29.6
22	Bus 13	Bus 12	Line	38.7
23	Bus 12	Bus 14	Line	30.2
24	Bus 12	Bus 15	Line	72.3
25	Bus 12	Bus 16	Line	14.2
26	Bus 14	Bus 15	Line	19.7
27	Bus 15	Bus 18	Line	87
28	Bus 15	Bus 23	Line	20.6
29	Bus 17	Bus 16	Line	4.2
30	Bus 18	Bus 19	Line	63.9
31	Bus 19	Bus 20	Line	0
32	Bus 21	Bus 22	Line	7.2
33	Bus 22	Bus 24	Line	67.1
34	Bus 24	Bus 23	Line	2.4
35	Bus 24	Bus 25	Line	17.9
36	Bus 25	Bus 26	Line	25.7
37	Bus 25	Bus 27	Line	16.8
38	Bus 27	Bus 28	Transformer	24.9
39	Bus 27	Bus 29	Line	39.5
40	Bus 27	Bus 30	Line	45
41	Bus 29	Bus 30	Line	23.3

Appendix A Table 32 %MVA by limit under contingency of branch 32

Branch no	From Name	To Name	Branch Device Type	% of MVA Limit
1	Bus 1	Bus 2	Line	72
2	Bus 1	Bus 3	Line	38.8
3	Bus 2	Bus 4	Line	51.1
4	Bus 2	Bus 5	Line	27.1
5	Bus 6	Bus 2	Line	65
6	Bus 3	Bus 4	Line	36.6
7	Bus 6	Bus 4	Line	46.1
8	Bus 4	Bus 12	Transformer	49.2
9	Bus 7	Bus 5	Line	26.2
10	Bus 6	Bus 7	Line	6.3
11	Bus 6	Bus 8	Line	127.4
12	Bus 6	Bus 9	Transformer	33.4
13	Bus 6	Bus 10	Transformer	57.4
14	Bus 6	Bus 28	Line	18
15	Bus 8	Bus 28	Line	32.8
16	Bus 9	Bus 10	Line	50.1
17	Bus 9	Bus 11	Line	24.8
18	Bus 10	Bus 17	Line	25.2
19	Bus 10	Bus 20	Line	32
20	Bus 10	Bus 21	Line	55.2
21	Bus 10	Bus 22	Line	26.2
22	Bus 13	Bus 12	Line	35.8
23	Bus 12	Bus 14	Line	26
24	Bus 12	Bus 15	Line	58.2
25	Bus 12	Bus 16	Line	22.4
26	Bus 14	Bus 15	Line	11.2
27	Bus 15	Bus 18	Line	36.4
28	Bus 15	Bus 23	Line	36.2
29	Bus 17	Bus 16	Line	20.7
30	Bus 18	Bus 19	Line	15.4
31	Bus 19	Bus 20	Line	24.2
32	Bus 21	Bus 22	Line	0
33	Bus 22	Bus 24	Line	51.8
34	Bus 24	Bus 23	Line	13.8
35	Bus 24	Bus 25	Line	17.7
36	Bus 25	Bus 26	Line	25.7
37	Bus 25	Bus 27	Line	16
38	Bus 27	Bus 28	Transformer	24.7
39	Bus 27	Bus 29	Line	39.5
40	Bus 27	Bus 30	Line	45
41	Bus 29	Bus 30	Line	23.3

Appendix A Table 33 %MVA by limit under contingency of branch 33

Branch no	From Name	To Name	Branch Device Type	% of MVA Limit
1	Bus 1	Bus 2	Line	72
2	Bus 1	Bus 3	Line	38.8
3	Bus 2	Bus 4	Line	51.1
4	Bus 2	Bus 5	Line	27
5	Bus 6	Bus 2	Line	64.6
6	Bus 3	Bus 4	Line	36.5
7	Bus 6	Bus 4	Line	45.3
8	Bus 4	Bus 12	Transformer	50.5
9	Bus 7	Bus 5	Line	26.1
10	Bus 6	Bus 7	Line	6.4
11	Bus 6	Bus 8	Line	128.7
12	Bus 6	Bus 9	Transformer	30.4
13	Bus 6	Bus 10	Transformer	52.4
14	Bus 6	Bus 28	Line	20.4
15	Bus 8	Bus 28	Line	40.1
16	Bus 9	Bus 10	Line	46.1
17	Bus 9	Bus 11	Line	23.5
18	Bus 10	Bus 17	Line	30.9
19	Bus 10	Bus 20	Line	38.9
20	Bus 10	Bus 21	Line	38.6
21	Bus 10	Bus 22	Line	16.5
22	Bus 13	Bus 12	Line	37.2
23	Bus 12	Bus 14	Line	28.5
24	Bus 12	Bus 15	Line	66.5
25	Bus 12	Bus 16	Line	15.6
26	Bus 14	Bus 15	Line	16.2
27	Bus 15	Bus 18	Line	22.8
28	Bus 15	Bus 23	Line	70.5
29	Bus 17	Bus 16	Line	7.1
30	Bus 18	Bus 19	Line	2.2
31	Bus 19	Bus 20	Line	30.8
32	Bus 21	Bus 22	Line	16.4
33	Bus 22	Bus 24	Line	0
34	Bus 24	Bus 23	Line	46.9
35	Bus 24	Bus 25	Line	12.9
36	Bus 25	Bus 26	Line	25.7
37	Bus 25	Bus 27	Line	33
38	Bus 27	Bus 28	Transformer	29.4
39	Bus 27	Bus 29	Line	39.5
40	Bus 27	Bus 30	Line	45.1
41	Bus 29	Bus 30	Line	23.3

Appendix A Table 34 %MVA by limit under contingency of branch 34

Branch no	From Name	To Name	Branch Device Type	% of MVA Limit
1	Bus 1	Bus 2	Line	72
2	Bus 1	Bus 3	Line	38.8
3	Bus 2	Bus 4	Line	51
4	Bus 2	Bus 5	Line	27.1
5	Bus 6	Bus 2	Line	65.1
6	Bus 3	Bus 4	Line	36.5
7	Bus 6	Bus 4	Line	46.8
8	Bus 4	Bus 12	Transformer	47.9
9	Bus 7	Bus 5	Line	26.3
10	Bus 6	Bus 7	Line	6.3
11	Bus 6	Bus 8	Line	128.2
12	Bus 6	Bus 9	Transformer	33.6
13	Bus 6	Bus 10	Transformer	57.9
14	Bus 6	Bus 28	Line	18.5
15	Bus 8	Bus 28	Line	34
16	Bus 9	Bus 10	Line	50.5
17	Bus 9	Bus 11	Line	25
18	Bus 10	Bus 17	Line	23.8
19	Bus 10	Bus 20	Line	29.8
20	Bus 10	Bus 21	Line	57.2
21	Bus 10	Bus 22	Line	28.7
22	Bus 13	Bus 12	Line	35.3
23	Bus 12	Bus 14	Line	24.8
24	Bus 12	Bus 15	Line	54.4
25	Bus 12	Bus 16	Line	24.4
26	Bus 14	Bus 15	Line	9
27	Bus 15	Bus 18	Line	41
28	Bus 15	Bus 23	Line	22.4
29	Bus 17	Bus 16	Line	24.7
30	Bus 18	Bus 19	Line	19.9
31	Bus 19	Bus 20	Line	22.1
32	Bus 21	Bus 22	Line	6
33	Bus 22	Bus 24	Line	62.4
34	Bus 24	Bus 23	Line	0
35	Bus 24	Bus 25	Line	16.8
36	Bus 25	Bus 26	Line	25.7
37	Bus 25	Bus 27	Line	19.3
38	Bus 27	Bus 28	Transformer	25.6
39	Bus 27	Bus 29	Line	39.5
40	Bus 27	Bus 30	Line	45
41	Bus 29	Bus 30	Line	23.3

Appendix A Table 35 %MVA by limit under contingency of branch 35

Branch no	From Name	To Name	Branch Device Type	% of MVA Limit
1	Bus 1	Bus 2	Line	72
2	Bus 1	Bus 3	Line	38.8
3	Bus 2	Bus 4	Line	51
4	Bus 2	Bus 5	Line	27.1
5	Bus 6	Bus 2	Line	65
6	Bus 3	Bus 4	Line	36.5
7	Bus 6	Bus 4	Line	46.2
8	Bus 4	Bus 12	Transformer	48.6
9	Bus 7	Bus 5	Line	26.5
10	Bus 6	Bus 7	Line	6.3
11	Bus 6	Bus 8	Line	125.5
12	Bus 6	Bus 9	Transformer	32.9
13	Bus 6	Bus 10	Transformer	55.7
14	Bus 6	Bus 28	Line	19
15	Bus 8	Bus 28	Line	37.6
16	Bus 9	Bus 10	Line	49
17	Bus 9	Bus 11	Line	24.3
18	Bus 10	Bus 17	Line	25.7
19	Bus 10	Bus 20	Line	32
20	Bus 10	Bus 21	Line	51.9
21	Bus 10	Bus 22	Line	25.2
22	Bus 13	Bus 12	Line	34.7
23	Bus 12	Bus 14	Line	25.6
24	Bus 12	Bus 15	Line	56.7
25	Bus 12	Bus 16	Line	21.9
26	Bus 14	Bus 15	Line	10.4
27	Bus 15	Bus 18	Line	36.3
28	Bus 15	Bus 23	Line	32.6
29	Bus 17	Bus 16	Line	19.9
30	Bus 18	Bus 19	Line	15.3
31	Bus 19	Bus 20	Line	24.2
32	Bus 21	Bus 22	Line	4.1
33	Bus 22	Bus 24	Line	43.8
34	Bus 24	Bus 23	Line	12.9
35	Bus 24	Bus 25	Line	0
36	Bus 25	Bus 26	Line	25.7
37	Bus 25	Bus 27	Line	25.8
38	Bus 27	Bus 28	Transformer	27.4
39	Bus 27	Bus 29	Line	39.5
40	Bus 27	Bus 30	Line	45.1
41	Bus 29	Bus 30	Line	23.3

Appendix A Table 36 %MVA by limit under contingency of branch 36

Branch no	From Name	To Name	Branch Device Type	% of MVA Limit
1	Bus 1	Bus 2	Line	72.6
2	Bus 1	Bus 3	Line	38.3
3	Bus 2	Bus 4	Line	49.3
4	Bus 2	Bus 5	Line	26.6
5	Bus 6	Bus 2	Line	62.9
6	Bus 3	Bus 4	Line	36.1
7	Bus 6	Bus 4	Line	45.4
8	Bus 4	Bus 12	Transformer	47.8
9	Bus 7	Bus 5	Line	24.9
10	Bus 6	Bus 7	Line	6.8
11	Bus 6	Bus 8	Line	127
12	Bus 6	Bus 9	Transformer	32.1
13	Bus 6	Bus 10	Transformer	56.1
14	Bus 6	Bus 28	Line	16.9
15	Bus 8	Bus 28	Line	28.7
16	Bus 9	Bus 10	Line	48.7
17	Bus 9	Bus 11	Line	24
18	Bus 10	Bus 17	Line	25.7
19	Bus 10	Bus 20	Line	32
20	Bus 10	Bus 21	Line	51
21	Bus 10	Bus 22	Line	24.6
22	Bus 13	Bus 12	Line	34.7
23	Bus 12	Bus 14	Line	25.4
24	Bus 12	Bus 15	Line	56.2
25	Bus 12	Bus 16	Line	21.8
26	Bus 14	Bus 15	Line	10
27	Bus 15	Bus 18	Line	36.4
28	Bus 15	Bus 23	Line	31.1
29	Bus 17	Bus 16	Line	19.5
30	Bus 18	Bus 19	Line	15.3
31	Bus 19	Bus 20	Line	24.2
32	Bus 21	Bus 22	Line	6.5
33	Bus 22	Bus 24	Line	42.4
34	Bus 24	Bus 23	Line	9.7
35	Bus 24	Bus 25	Line	13
36	Bus 25	Bus 26	Line	0
37	Bus 25	Bus 27	Line	12.9
38	Bus 27	Bus 28	Transformer	22.2
39	Bus 27	Bus 29	Line	39.4
40	Bus 27	Bus 30	Line	45
41	Bus 29	Bus 30	Line	23.3

Appendix A Table 37 %MVA by limit under contingency of branch 37

Branch no	From Name	To Name	Branch Device Type	% of MVA Limit
1	Bus 1	Bus 2	Line	71.9
2	Bus 1	Bus 3	Line	38.9
3	Bus 2	Bus 4	Line	51.3
4	Bus 2	Bus 5	Line	27.1
5	Bus 6	Bus 2	Line	64.8
6	Bus 3	Bus 4	Line	36.6
7	Bus 6	Bus 4	Line	45.3
8	Bus 4	Bus 12	Transformer	50.7
9	Bus 7	Bus 5	Line	26.2
10	Bus 6	Bus 7	Line	6.4
11	Bus 6	Bus 8	Line	122.8
12	Bus 6	Bus 9	Transformer	34.9
13	Bus 6	Bus 10	Transformer	59.1
14	Bus 6	Bus 28	Line	15.7
15	Bus 8	Bus 28	Line	27.6
16	Bus 9	Bus 10	Line	51.6
17	Bus 9	Bus 11	Line	24.8
18	Bus 10	Bus 17	Line	25
19	Bus 10	Bus 20	Line	32.1
20	Bus 10	Bus 21	Line	57
21	Bus 10	Bus 22	Line	28.6
22	Bus 13	Bus 12	Line	35.6
23	Bus 12	Bus 14	Line	26.6
24	Bus 12	Bus 15	Line	60
25	Bus 12	Bus 16	Line	22.7
26	Bus 14	Bus 15	Line	12.3
27	Bus 15	Bus 18	Line	36.1
28	Bus 15	Bus 23	Line	41
29	Bus 17	Bus 16	Line	21.2
30	Bus 18	Bus 19	Line	15
31	Bus 19	Bus 20	Line	24.4
32	Bus 21	Bus 22	Line	5
33	Bus 22	Bus 24	Line	61.1
34	Bus 24	Bus 23	Line	19.3
35	Bus 24	Bus 25	Line	25.9
36	Bus 25	Bus 26	Line	25.7
37	Bus 25	Bus 27	Line	0
38	Bus 27	Bus 28	Transformer	21
39	Bus 27	Bus 29	Line	39.5
40	Bus 27	Bus 30	Line	45
41	Bus 29	Bus 30	Line	23.3

Appendix A Table 38 %MVA by limit under contingency of branch 38

Branch no	From Name	To Name	Branch Device Type	% of MVA Limit
1	Bus 1	Bus 2	Line	74.3
2	Bus 1	Bus 3	Line	34.5
3	Bus 2	Bus 4	Line	38.5
4	Bus 2	Bus 5	Line	23.9
5	Bus 6	Bus 2	Line	51.6
6	Bus 3	Bus 4	Line	32.4
7	Bus 6	Bus 4	Line	43.3
8	Bus 4	Bus 12	Transformer	32.3
9	Bus 7	Bus 5	Line	21.5
10	Bus 6	Bus 7	Line	9.3
11	Bus 6	Bus 8	Line	106.9
12	Bus 6	Bus 9	Transformer	34.3
13	Bus 6	Bus 10	Transformer	63
14	Bus 6	Bus 28	Line	5.8
15	Bus 8	Bus 28	Line	5.8
16	Bus 9	Bus 10	Line	53.5
17	Bus 9	Bus 11	Line	26.5
18	Bus 10	Bus 17	Line	20.7
19	Bus 10	Bus 20	Line	26.4
20	Bus 10	Bus 21	Line	73.5
21	Bus 10	Bus 22	Line	39.4
22	Bus 13	Bus 12	Line	69.2
23	Bus 12	Bus 14	Line	34.2
24	Bus 12	Bus 15	Line	84.6
25	Bus 12	Bus 16	Line	40.2
26	Bus 14	Bus 15	Line	26.9
27	Bus 15	Bus 18	Line	51.5
28	Bus 15	Bus 23	Line	88
29	Bus 17	Bus 16	Line	57.1
30	Bus 18	Bus 19	Line	31.1
31	Bus 19	Bus 20	Line	19.1
32	Bus 21	Bus 22	Line	20.4
33	Bus 22	Bus 24	Line	116.1
34	Bus 24	Bus 23	Line	64.6
35	Bus 24	Bus 25	Line	120.6
36	Bus 25	Bus 26	Line	25.8
37	Bus 25	Bus 27	Line	87.8
38	Bus 27	Bus 28	Transformer	0
39	Bus 27	Bus 29	Line	39.8
40	Bus 27	Bus 30	Line	45.5
41	Bus 29	Bus 30	Line	23.4

Appendix A Table 39 %MVA by limit under contingency of branch 39

Branch no	From Name	To Name	Branch Device Type	% of MVA Limit
1	Bus 1	Bus 2	Line	72.1
2	Bus 1	Bus 3	Line	38.9
3	Bus 2	Bus 4	Line	51.3
4	Bus 2	Bus 5	Line	27.2
5	Bus 6	Bus 2	Line	65.2
6	Bus 3	Bus 4	Line	36.6
7	Bus 6	Bus 4	Line	46.1
8	Bus 4	Bus 12	Transformer	49.4
9	Bus 7	Bus 5	Line	26.4
10	Bus 6	Bus 7	Line	6.3
11	Bus 6	Bus 8	Line	127.2
12	Bus 6	Bus 9	Transformer	33.4
13	Bus 6	Bus 10	Transformer	57.6
14	Bus 6	Bus 28	Line	18.2
15	Bus 8	Bus 28	Line	33.7
16	Bus 9	Bus 10	Line	50.2
17	Bus 9	Bus 11	Line	25.1
18	Bus 10	Bus 17	Line	24.9
19	Bus 10	Bus 20	Line	31.9
20	Bus 10	Bus 21	Line	54.2
21	Bus 10	Bus 22	Line	26.8
22	Bus 13	Bus 12	Line	36
23	Bus 12	Bus 14	Line	26.1
24	Bus 12	Bus 15	Line	58.5
25	Bus 12	Bus 16	Line	22.5
26	Bus 14	Bus 15	Line	11.4
27	Bus 15	Bus 18	Line	36.5
28	Bus 15	Bus 23	Line	36.9
29	Bus 17	Bus 16	Line	20.8
30	Bus 18	Bus 19	Line	15.4
31	Bus 19	Bus 20	Line	24.2
32	Bus 21	Bus 22	Line	6.3
33	Bus 22	Bus 24	Line	53.3
34	Bus 24	Bus 23	Line	14.6
35	Bus 24	Bus 25	Line	20.5
36	Bus 25	Bus 26	Line	25.7
37	Bus 25	Bus 27	Line	15.5
38	Bus 27	Bus 28	Transformer	25.2
39	Bus 27	Bus 29	Line	0
40	Bus 27	Bus 30	Line	88.1
41	Bus 29	Bus 30	Line	15.6

Appendix A Table 40 %MVA by limit under contingency of branch 40

Branch no	From Name	To Name	Branch Device Type	% of MVA Limit
1	Bus 1	Bus 2	Line	72.2
2	Bus 1	Bus 3	Line	39
3	Bus 2	Bus 4	Line	51.4
4	Bus 2	Bus 5	Line	27.2
5	Bus 6	Bus 2	Line	65.2
6	Bus 3	Bus 4	Line	36.7
7	Bus 6	Bus 4	Line	46.2
8	Bus 4	Bus 12	Transformer	49.5
9	Bus 7	Bus 5	Line	26.5
10	Bus 6	Bus 7	Line	6.3
11	Bus 6	Bus 8	Line	127
12	Bus 6	Bus 9	Transformer	33.5
13	Bus 6	Bus 10	Transformer	57.6
14	Bus 6	Bus 28	Line	18.3
15	Bus 8	Bus 28	Line	34
16	Bus 9	Bus 10	Line	50.3
17	Bus 9	Bus 11	Line	25.1
18	Bus 10	Bus 17	Line	24.9
19	Bus 10	Bus 20	Line	31.9
20	Bus 10	Bus 21	Line	54.3
21	Bus 10	Bus 22	Line	26.8
22	Bus 13	Bus 12	Line	36.1
23	Bus 12	Bus 14	Line	26.1
24	Bus 12	Bus 15	Line	58.6
25	Bus 12	Bus 16	Line	22.6
26	Bus 14	Bus 15	Line	11.5
27	Bus 15	Bus 18	Line	36.5
28	Bus 15	Bus 23	Line	37.2
29	Bus 17	Bus 16	Line	20.8
30	Bus 18	Bus 19	Line	15.4
31	Bus 19	Bus 20	Line	24.2
32	Bus 21	Bus 22	Line	6.3
33	Bus 22	Bus 24	Line	53.8
34	Bus 24	Bus 23	Line	14.9
35	Bus 24	Bus 25	Line	21.2
36	Bus 25	Bus 26	Line	25.7
37	Bus 25	Bus 27	Line	15.2
38	Bus 27	Bus 28	Transformer	25.4
39	Bus 27	Bus 29	Line	89.4
40	Bus 27	Bus 30	Line	0
41	Bus 29	Bus 30	Line	69.5

Appendix A Table 41 %MVA by limit under contingency of branch 41

Branch no	From Name	To Name	Branch Device Type	% of MVA Limit
1	Bus 1	Bus 2	Line	71.9
2	Bus 1	Bus 3	Line	38.9
3	Bus 2	Bus 4	Line	51.2
4	Bus 2	Bus 5	Line	27.1
5	Bus 6	Bus 2	Line	65
6	Bus 3	Bus 4	Line	36.6
7	Bus 6	Bus 4	Line	46.1
8	Bus 4	Bus 12	Transformer	49.3
9	Bus 7	Bus 5	Line	26.3
10	Bus 6	Bus 7	Line	6.3
11	Bus 6	Bus 8	Line	127.5
12	Bus 6	Bus 9	Transformer	33.3
13	Bus 6	Bus 10	Transformer	57.5
14	Bus 6	Bus 28	Line	18.1
15	Bus 8	Bus 28	Line	33.1
16	Bus 9	Bus 10	Line	50.1
17	Bus 9	Bus 11	Line	24.9
18	Bus 10	Bus 17	Line	25
19	Bus 10	Bus 20	Line	31.9
20	Bus 10	Bus 21	Line	54
21	Bus 10	Bus 22	Line	26.6
22	Bus 13	Bus 12	Line	35.8
23	Bus 12	Bus 14	Line	26
24	Bus 12	Bus 15	Line	58.3
25	Bus 12	Bus 16	Line	22.5
26	Bus 14	Bus 15	Line	11.3
27	Bus 15	Bus 18	Line	36.5
28	Bus 15	Bus 23	Line	36.4
29	Bus 17	Bus 16	Line	20.6
30	Bus 18	Bus 19	Line	15.4
31	Bus 19	Bus 20	Line	24.2
32	Bus 21	Bus 22	Line	6.1
33	Bus 22	Bus 24	Line	52.4
34	Bus 24	Bus 23	Line	14.2
35	Bus 24	Bus 25	Line	19.1
36	Bus 25	Bus 26	Line	25.7
37	Bus 25	Bus 27	Line	16.1
38	Bus 27	Bus 28	Transformer	24.9
39	Bus 27	Bus 29	Line	15.6
40	Bus 27	Bus 30	Line	70.2
41	Bus 29	Bus 30	Line	0

Appendix B

This section provides the detail data of LMPs on each bus during contingency at each branch:

Appendix B Table 1 LMPs of all buses during contingency at branch 1

Bus Number	MW Marg. Cost	Bus Number	MW Marg. Cost
1	2.94	16	3.51
2	3.5	17	3.51
3	3.48	18	3.52
4	3.5	19	3.52
5	3.51	20	3.52
6	3.51	21	3.51
7	3.51	22	3.51
8	3.51	23	3.52
9	3.51	24	3.52
10	3.51	25	3.52
11	3.51	26	3.54
12	3.5	27	3.52
13	3.5	28	3.52
14	3.51	29	3.54
15	3.51	30	3.55
Highest LMP Bus		30	
Highest LMP		3.55	

Appendix B Table 2 LMPs of all buses during contingency at branch 2

Bus Number	MW Marg. Cost	Bus Number	MW Marg. Cost
1	2.94	16	3.54
2	3.5	17	3.54
3	3.54	18	3.55
4	3.53	19	3.56
5	3.52	20	3.55
6	3.54	21	3.55
7	3.54	22	3.55
8	3.54	23	3.55
9	3.54	24	3.56
10	3.54	25	3.56
11	3.54	26	3.57
12	3.53	27	3.55
13	3.53	28	3.55
14	3.55	29	3.57
15	3.55	30	3.58
Highest LMP Bus		30	
Highest LMP		3.58	

Appendix B Table 3 LMPs of all buses during contingency at branch 3, 4, 5, 7, 9, 11, 17, 19, 20, 22, 24, 31, 39, and 40

Bus Number	MW Marg. Cost	Bus Number	MW Marg. Cost
1	3.16	16	3.16
2	3.16	17	3.16
3	3.16	18	3.16
4	3.16	19	3.16
5	3.16	20	3.16
6	3.16	21	3.16
7	3.16	22	3.16
8	3.16	23	3.16
9	3.16	24	3.16
10	3.16	25	3.16
11	3.16	26	3.16
12	3.16	27	3.16
13	3.16	28	3.16
14	3.16	29	3.16
15	3.16	30	3.16
Highest LMP Bus		30	
Highest LMP		3.16	

Appendix B Table 4 LMPs of all buses during contingency at branch 6

Bus Number	MW Marg. Cost	Bus Number	MW Marg. Cost
1	2.94	16	3.46
2	3.42	17	3.46
3	2.94	18	3.47
4	3.45	19	3.47
5	3.44	20	3.47
6	3.45	21	3.46
7	3.45	22	3.46
8	3.46	23	3.47
9	3.45	24	3.47
10	3.46	25	3.47
11	3.45	26	3.48
12	3.45	27	3.46
13	3.45	28	3.46
14	3.46	29	3.48
15	3.46	30	3.5
Highest LMP Bus		30	
Highest LMP		3.5	

Appendix B Table 5 LMPs of all buses during contingency at branch 8

Bus Number	MW Marg. Cost	Bus Number	MW Marg. Cost
1	3.08	16	3.13
2	3.08	17	3.12
3	3.08	18	3.12
4	3.08	19	3.12
5	3.08	20	3.13
6	3.08	21	3.14
7	3.08	22	3.16
8	3.46	23	3.23
9	3.1	24	3.23
10	3.12	25	3.27
11	3.1	26	3.34
12	3.13	27	3.28
13	3.13	28	3.28
14	3.13	29	3.13
15	3.13	30	3.12
Highest LMP Bus		8	
Highest LMP		3.46	

Appendix B Table 6 LMPs of all during contingency at branch 10, 15, 18, 21, 23-30, 32 34-37, 41

Bus Number	MW Marg. Cost	Bus Number	MW Marg. Cost
1	3.08	16	3.08
2	3.08	17	3.08
3	3.08	18	3.08
4	3.08	19	3.08
5	3.08	20	3.08
6	3.08	21	3.08
7	3.08	22	3.08
8	3.08	23	3.08
9	3.08	24	3.08
10	3.08	25	3.08
11	3.08	26	3.08
12	3.08	27	3.08
13	3.08	28	3.08
14	3.08	29	3.08
15	3.08	30	3.08
Highest LMP Bus		Equal at all buses	
Highest LMP		3.08	

Appendix B Table 7 LMPs of all buses during contingency at branch 12

Bus Number	MW Marg. Cost	Bus Number	MW Marg. Cost
1	3.08	16	3.11
2	3.08	17	3.12
3	3.08	18	3.12
4	3.08	19	3.12
5	3.08	20	3.12
6	3.08	21	3.13
7	3.08	22	3.13
8	3.46	23	3.13
9	3.12	24	3.15
10	3.12	25	3.23
11	3.12	26	3.23
12	3.11	27	3.27
13	3.11	28	3.34
14	3.11	29	3.28
15	3.12	30	3.28
Highest LMP Bus		8	
Highest LMP		3.46	

Appendix B Table 8 LMPs of all buses during contingency at branch 13

Bus Number	MW Marg. Cost	Bus Number	MW Marg. Cost
1	3.39	16	3.39
2	3.39	17	3.39
3	3.39	18	3.39
4	3.39	19	3.39
5	3.39	20	3.39
6	3.39	21	3.39
7	3.39	22	3.39
8	3.39	23	3.39
9	3.39	24	3.39
10	3.39	25	3.39
11	3.39	26	3.39
12	3.39	27	3.39
13	3.39	28	3.39
14	3.39	29	3.39
15	3.39	30	3.39
Highest LMP Bus		1	
Highest LMP		3.39	

Appendix B Table 9 LMPs of all buses during contingency at branch 14

Bus Number	MW Marg. Cost	Bus Number	MW Marg. Cost
1	3.08	16	3.11
2	3.08	17	3.11
3	3.08	18	3.11
4	3.08	19	3.11
5	3.08	20	3.11
6	3.08	21	3.12
7	3.08	22	3.12
8	3.46	23	3.13
9	3.1	24	3.16
10	3.11	25	3.26
11	3.1	26	3.26
12	3.1	27	3.32
13	3.1	28	3.41
14	3.11	29	3.33
15	3.11	30	3.33
Highest LMP Bus		8	
Highest LMP		3.46	

Appendix B Table 10 LMPs of all buses during contingency at branch 16

Bus Number	MW Marg. Cost	Bus Number	MW Marg. Cost
1	3.08	16	3.11
2	3.08	17	3.12
3	3.08	18	3.12
4	3.08	19	3.12
5	3.08	20	3.12
6	3.08	21	3.13
7	3.08	22	3.13
8	3.46	23	3.13
9	3.08	24	3.16
10	3.12	25	3.23
11	3.08	26	3.23
12	3.11	27	3.27
13	3.11	28	3.34
14	3.11	29	3.28
15	3.12	30	3.28
Highest LMP Bus		8	
Highest LMP		3.46	

Appendix B Table 11 LMPs of all buses during contingency at branch 33

Bus Number	MW Marg. Cost	Bus Number	MW Marg. Cost
1	3.08	16	3.1
2	3.08	17	3.09
3	3.08	18	3.11
4	3.08	19	3.1
5	3.08	20	3.1
6	3.08	21	3.09
7	3.08	22	3.09
8	3.46	23	3.15
9	3.08	24	3.2
10	3.09	25	3.26
11	3.08	26	3.26
12	3.1	27	3.29
13	3.1	28	3.34
14	3.11	29	3.3
15	3.12	30	3.31
Highest LMP Bus		8	
Highest LMP		3.46	

Appendix B Table 12 LMPs of all buses during contingency at branch 38

Bus Number	MW Marg. Cost	Bus Number	MW Marg. Cost
1	2.94	16	22.44
2	1.87	17	-38.47
3	6.44	18	83.82
4	7.21	19	35.98
5	-0.98	20	10.41
6	-3.72	21	-111.68
7	-2.61	22	-126.4
8	-3.74	23	395.5
9	-42.87	24	715.58
10	-64.29	25	1899.89
11	-42.77	26	1955
12	84.5	27	1998.59
13	83.45	28	-3.73
14	131.86	29	2097.97
15	162.25	30	2168.07
Highest LMP Bus		30	
Highest LMP		2168.07	