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Utilization of Distributed Generation in Power System Peak Hour Load Shedding Reduction

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Abstract

An approach to utilize Distributed Generation (DG) to minimize the total load shedding by analyzing the power system in transactive energy framework is proposed. An algorithm to optimize power system in forward and spot markets to maximize an electric utility's profit by optimizing purchase of power from distributed generators is developed. The proposed algorithm is a multi-objective optimization with the main objective to maximize a utility's profit by minimizing overall cost of production, load shedding, and purchase of power from distributed generators. The proposed technique provides improved quantitative benefits of DG dispatch at specific locations which are analyzed using three metrics for comparison. The scheme justifies purchase of power from DG to maximize utility's profit and to minimize load shedding of the system. This work also proposes a method to price power in forward and spot markets using existing Locational Marginal Pricing methods. Transactive accounting has been performed to quantify the consumer payments in forward and spot markets and to determine profit of each transaction. The algorithm is tested in two test systems; a 6-bus system and modified IEEE 14-bus system. The results show that by investing in DG, utility benefits from profit increase, load shedding reduction, and transmission line loading improvement.

KEY WORDS

Distributed generation, Transactive Energy, Optimal Power Flow, Locational Marginal Pricing, Load Shedding, MATPOWER

Chapter 1

Introduction

1.1 Overview

The purpose of this chapter is to give a brief introduction about this work and to introduce various topics such as power system economics, power flow techniques, distributed energy resources, and transactive energy used in this work. Restructuring of power Market over the years and its current status in US is introduced first. Major government acts which paved way for deregulation in power market and the current status of deregulation is discussed. Next, existing power market structure and classification of energy market into Day Ahead Market and Real Time market is examined. This is followed by Locational Marginal Pricing (which is the pricing scheme used to charge customers), Economic Dispatch, Optimal Power Flow, and Distributed Energy Resources. Transactive Energy framework and various transactive energy markets which is still in the planning phase are reviewed next. The next section deals with historic review of economic dispatch, optimal power flow, LMP and Distributed Energy Resources. Finally, scope and contribution of this work is presented in next section.

1.1.1 Restructuring of Power Market

In the mid part of the twentieth century, the cost of electricity kept on declining as utilities started to build larger power plants, with increased efficiency and reduced production costs. Increased electric demand required more and larger plants, which reduced costs further as well as increasing the utility rate base. Consumers had abundant, low cost power; regulators oversaw declining rates, increased electrification, and economic growth; and utilities and stockholders gained financially. Electric utility started becoming monopoly in most of the places. It forced government to have regulations on these utilities. “Regulation of utilities is based on the inherent risk that a single monopoly supplier will overcharge consumers due to the lack of competition and high demand” [56].

Usually these large suppliers will have lack of competition although there is very high demand for power. It became primarily responsibility of electric utilities to supply power to all customers within its area of operation. In this traditional system, even if the utility purchases power from neighboring utilities, it was just to serve the retail customers in its service territory.

In a regulated utility environment [56], customers are allocated to classes that each have different rates. Rates are calculated based on recovery costs used to serve each class of customers. Typical customer classes include residential, small and large commercial, and industrial.

In late nineteenth century, when the utilities were not regulated, there was a huge rise in demand of power. In densely populated urban areas where more people were likely to use power, utilities competed for the same customers, including building duplicate distribution systems. As a result of this, municipalities stepped in, regulating the number of utilities, requiring universal service, and restricting each utility to service in specific areas of town to avoid the construction of duplicate systems.

By 1900, [56] States granted monopoly franchise to utilities to serve in certain territories. However pricing and services provided by these utilities were monitored and regulated by state. More and more utilities started coming up which in turn forced state to improve existing laws and regulations to accommodate all upcoming privately owned utilities. In 1907, Georgia, New York, and Wisconsin were the first three states to establish state public service commissions and regulate electric utilities. Federal Water Power Act of 1920, coordinated the development of hydroelectric projects in the United States. Federal Power Commission (FPC), presently the Federal Energy Regulatory Commission (FERC), created then, was the regulating and licensing authority for the same. FPC also regulated interstate power transfer and natural gas industries. FPC's regulatory jurisdiction was expanded by Federal Power Act of 1935, to include all interstate electricity transmission and sales of power. [24]

i Public Utility Holding Company Act (PUHCA) of 1935

In 1930s, state could not control the utility holding companies that owned most of the resources for power production and they engaged mainly in interstate commerce. Congress passed the Public Utility Holding Company Act (PUHCA) in 1935 (also known as Wheeler-Rayburn Act) since state regulation then was not sufficient to control these holding companies. Securities and Exchange

Commission (SEC) became more powerful and responsible with PUHCA. SEC started regulating holding companies prior to engaging in a non-utility business. Also, such businesses were kept separate from the utility's regulated business. SEC breaks up most of the large interstate holding companies and made them separate integrated utilities serving power to SEC specified geographic areas. This gave state more control over utilities to regulate their rates and services. Furthermore, PUHCA did not permit utility holding companies to engage in business that deviates its behaviour from single integrated utility .

Twenty years from 1940 through 1960 saw extensive growth in power industry. More and more generating units came into existence which reduced costs as well. Reliability and security of power system were not given utmost importance during this period. However the Great Northeast Blackout of 1965 drastically changed the regulators view of reliability in power system. One fine evening [11], the entire Northeast electric services came to complete shutdown following sudden increase in demand due to failure of a few lines causing adjacent transmission breakers to trip. There was a complete outage of power in all of the state of New York; the states of Connecticut, Rhode Island, Massachusetts, and Vermont; parts of New Hampshire, New Jersey, and Pennsylvania; and major parts of Canadian province of Ontario with some of them lasting up to 13 hours. This is majorly due to excessive dependence for power from adjacent utilities and less regulations for system reliability. Vassell in [24, 56], explains in details the event, cause and aftermath of 1965 blackout.

ii Formation of North American Electric Reliability Council (NERC) in 1968

In the wake of Northeast Blackout, Northeast Power Coordinating Council (NPCC) was formed in 1966, and comprised of all major utilities of Northeast region. NPCC was the first Regional Reliability Council in North America and main objective was to enhance reliability of bulk electric power supply. Later in 1968, with the recommendation of the FPC, National Electric Reliability Council (NERC) was formed by the electric utility industries "to promote the reliability of bulk electric supply in the electric utility systems of North America".

NERC divided the nation into ten reliability regions. The largest council is the Western Systems Coordinating Council (WSCC). The smallest is the Mid Atlantic Coordinating Council (MAAC). System planning and operating criteria of each utility were maintained by reliability councils in order to ascertain bulk power reliability. NERC provided necessary coordination to these Regional Reliability Councils which established guidelines and criteria within their geographic area for their member systems regarding the utility operation such as transmission system planning, generation installation, and emergency procedures.

iii Public Utility Regulatory Policies Act (PURPA)

Due to the Oil Embargo of 1970 utilities started to depend less on foreign fuels. They started building more and more plants based on coal and nuclear technologies. Although these plants costed much more to build than simple oil or natural gas fired generators, they were expected to gain in future due to the volatile price range of foreign fuel. Consequently, the fixed costs of utility operations increased, further increasing retail electricity prices. This created opportunities for small scale production plants such as small hydropower sites, industrial cogeneration, and wind and solar farms. In order to promote these non utility production, and to encourage efficient use of fossil fuel, Congress passed Public Utility Regulatory Policies Act (PURPA) in 1978. PURPA enabled non utility power suppliers, referred to as “qualifying facilities” or “QFs”, to enter into wholesale market and sell power. [56]

iv Deregulation

Regulators [56] tried to push for conservation and other alternative sources of energy thereby to have a check in retail rates. Furthermore, least cost planning and Integrated Resource Planning (IRP) processes were chosen by regulators to meet the challenges of supply and demand mismatch. A detailed demand forecasts in a public process were carried for efficient planning for new generating plants. At the same time, due to natural gas regulation utilities had a hard time in using natural gas as a generating fuel. FERC (which was created by the Natural Gas Policy Act) issued orders in the late 1980s, opening access to transport natural gas from surplus areas to deficient areas which was the first step towards deregulation. Later in 1992, FERC issued Mega-Notice of Proposed Rulemaking or Mega-NOPR which marked the end of gas price regulation. Expertise of restructuring Natural Gas industry by FERC paved the way for electric industry deregulation at later stages. Regardless of all these efforts, rates were still high and there were significant differences between adjacent utilities which used different generating fuels. This was very prominent in

California. All these slowly led to deregulation in those areas and allowed consumers to have direct access to wholesale suppliers.

Ultimately, the National Energy Policy Act of 1992 (EPACT) authorized utilities to produce power as exempt wholesale generators, or EWAGS. EWAGs are exempt from price regulation and can sell power to other utilities. They also had open access to the transmission system and followed "market-based rate policy". In this deregulated supply system, "generation and distribution are unbundled and customers can purchase from any suppliers on the grid". Independent System Operator (ISO) does the transmission scheduling. Market mechanisms like the power exchange was used for purchase of power. [56]

Later in 1996, FERC issued Order No. 888 addressing "Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities". Order No. 888, is often cited as the "Deregulation" of the electric industry. In 1999, FERC issued Order No.2000 promoting voluntarily formation of Regional Transmission Organizations (RTO). With Order 2000, FERC requested all utilities to place their transmission facilities under the control of RTO. Western U.S. Energy Crisis of 2001 impacted California with huge energy crisis resulting in several small and large scale blackouts throughout the state. It also saw the collapse of several large energy companies. It was devastating as whole sale energy price increased to an uncontrollable extent. California energy market crisis and 2003 Northeast blackout were a wakeup call and Congress enacted Energy Policy Act of 2005 (EPAct 2005). EPAct 2005 changed US Energy policies and was great benefit to utilities as it provides tax benefits and loan guarantees for energy production of various types. PUHCA of 1935 was revoked by passing this act. In 2007, FERC issued Order No.890 to deal with some of the flaws of Order No. 888. With Order No.890 FERC increased transparency in rules for planning and use of transmission system. The main objective was "to strengthen the *pro forma* Open Access Transmission Tariff to ensure that it achieves its original purpose of remedying undue discrimination " [15, 47]

According to the Energy Information Administration (EIA) [3], at the present restructuring is complete in several states including Pennsylvania, New Jersey, Maryland, Michigan, Texas, Oregon, Illinois, Maine, and District of Columbia. EIA [3] defines restructuring as "monopoly system of electric utilities has been replaced with competing sellers". In these states Deregulation of power system is active. However, majority of the states such as Washington, Idaho, Utah, Kansas, Louisiana, Mississippi, Alabama, and Florida are still regulated. However there is no deregulation on retail choice which is explained in detail in the next section. On the other hand, in some of the states like California, Nevada, Arizona, New Mexico, Montana, Arkansas, and Virginia, restructuring has been suspended.

1.1.2 Power Market

Power Market is the market where financial and physical trading of electricity takes place. Power sale happens well in advance and also in real time. Accordingly, energy market is classified into Day Ahead (DA) Market and Real Time (RT) Market. Day Ahead Markets [52] are based on bids and auctions. Contracts are made well in advance based on energy price bids. DA auctions are performed based on complex calculations considering the generation cost as well system constraints. Seller and buyer negotiate for prices until bids are accepted and trade is accepted. Each auction are specified by a set of conditions: bidding rules, bid acceptance rules, and settlement rules. Major portion of power trade is dealt in DA auctions. Real Time market is used to solve the mismatch with day ahead forecasted load and real time load.The Real time price is determined by actual (real time) supply and demand. This includes power traded under forward contract and real time market. Power is traded with spot price fixed by ISO rather than using bids and contracts. A price is announced and buyers and sellers respond. If the market does not clear, a new price is announced. Unlike DA market, there is no waiting until the right price is discovered. In RT Market, most of the ISOs perform security constrained economic dispatch (SCED) every 5 minutes to update the price using the latest generation output and load status. Whatever power is not traded in DA market is cleared in RT market.

In wholesale and retail levels, there are two different approaches of power market. At wholesale level centralized generation market and bilateral market are used whereas in retail level, vertically integrated approach and retail choice are used.

In a traditional bilateral market buyers and sellers trade power directly with the help of a broker. Most distinct feature [23] of bilateral trade is its ”continual process of trading, with prices unique to each transaction”. Here, value of fulfilling a bilateral trade is relative and depends on the benefits of seller as well as buyer and has very little to do with actual demand value power sale. Although, bilateral markets are efficient in providing bulk power supply, they are too slow in balancing real time market needs as well as transmission security. Complexity of solving unit commitment problems and transmission problems simultaneously makes bilateral system too slow. Most of the time, bilateral market trades would not reach an equilibrium, where buyers and sellers accept a common price due to bargaining problems. Even if equilibrium is reached there is no guarantee that it will be the least cost in a market. Most of the transactions in Southeast and West (excluding California) are done bilaterally. On the other hand, in a centralized market scheme, there is a centralized exchange of power with uniform clearing price. Due to transparent nature of centralized market this is more efficient and faster. It is based on a centralized unit commitment. Centralized market scheme provides minimal transaction cost, transparency in trade, and efficient way to monitor exchanges by regulating authorities. However if the authority and control structure is not enough to govern, these contract forms become inefficient for traders. Furthermore, they are confined mainly to day ahead and spot transactions due to incapability of model to predict market ahead. Hence, they are good for establishing longer term contracts. In addition day-ahead energy market usually clears before transmission market opens, hence traders must encounter transmission charges later. [23, 52]

Usually in traditional power system, generation, transmission, and distribution are managed by one utility in a geographic area which is responsible for providing power to everyone in that region. The price paid by a retail customer is the aggregate sum of generation, transmission, and distribution of power and usually difficult to segregate them. This is called vertical integrated approach. It is often easy for regulators to manage markets which are vertically integrated. However, end-use customers do not have a choice to choose their supplier. Due to the nature of this approach, there is a monopoly in the market. On the contrary, in Retail Choice approach, end-use customers have a choice on choosing their electricity from competitive suppliers. It is based on bid based generation market. Due to deregulation the transmission lines are open for transferring power and hence marketers could sell power to any customers in a region. Retail marketers could acquire power either from their own power plants or could buy from other wholesale power market.

i Status of Retail Choice Approach

As per U.S. Energy Information Administration [2], as of 2012, seventeen states and District of Columbia have adopted retail choice approach by 2012. In most of these states, residential customers participation is significantly low compared to industrial and commercial customers. However, in Texas since participation is mandated for all customers, percentage of residential customer sales provided by competitive suppliers due to retail choice is as high as 60%. States like New York, Connecticut and Massachusetts also shows notably an increase in percentage of sales provided by competitive suppliers since the program started in respective states.

The seventeen states which adopted Retail Choice approach are as follows : New York, Connecticut, Rhode Island, Massachusetts, New Hampshire, District of Columbia, Maryland, Delaware, New Jersey, Pennsylvania, Ohio, Michigan, Illinois, Montana, Oregon, California, and Texas. Remaining thirty three states are still following vertical integration approach.

1.1.3 Locational Marginal Pricing

If a transmission line is not constrained and if there are no losses in the line, cheapest generating unit will be selected by ISO to meet the load demand at all locations. If the current generating unit reaches its limit, next least expensive unit will be chosen. In this case, the price of electricity is the same across all locations. This price is called market clearing price. But often even before the first generator reaches its limit, the system operator has to turn on another generator due to congestion in the transmission lines. If a transmission line reaches its thermal limit, a more expensive generating unit will be scheduled, since the cheaper generators alone could not meet the load demand. As a result, prices at those locations could go higher. Furthermore, transmission of power through very long transmission lines or through higher-resistive lines could bring significant loss in transmitted power. Consequently, even if there is no congestion, transmission losses lead to varying prices at different locations. This is often referred to as transport cost of power. Electricity prices vary with location and there is a need to calculate cost of power, based on location and all other factors mentioned above. This paved way to the concept of Locational Marginal Pricing (LMP). In [54] LMP is defined as the lowest cost of serving (a hypothetical) next incremental MW at a bus by optimizing all generator bids and transmission system conditions. It is the least cost dispatch of next incremental megawatt of electric energy at a specific bus considering the generation marginal costs and the physical aspects of the transmission system. It is basically the cost of optimally supplying an increment of load at a particular location while satisfying all operational constraints. New England ISO [37] explains some of the key features of LMP. LMP at location of each marginal unit is always equal to its offer price since any increment of load at that particular location will be delivered from the marginal units. Also, LMP at any location will be a linear combination of the offer prices at marginal locations. This follows, LMPs at some locations can be higher than the highest offer price. Furthermore, LMP can be negative as well at some locations. If there is no congestion and no losses, the LMP will be the same at all locations.

Article developed by Synapse Energy Economics [14] for American Public Power Association, explains LMP based on operations research theory, which is designed to achieve two economic objectives simultaneously. The first objective is to minimize the cost of generating enough electricity to meet load by using the least-cost set of available generators possible given various constraints. This is known as least-cost, security-constrained dispatch. The second objective is to produce the instantaneous price of electricity, at every point in the system, which reflects the instantaneous short-run marginal cost of serving one incremental unit of load at that location. At present there are two major classes of LMP models, one using ACOPF and the other using DCOPF. Although DCOPF lacks accuracy in calculation compared to ACOPF, DCOPF is still prefered by most ISOs due to its simplicity in calculation and financial consistency. Currently only New York ISO employs ACOPF for LMP calculation. ISOs such as PJM, New England ISO, California ISO, and Midwest ISO employ DCOPF.

LMPs [37] are usually produced as a result of economic dispatch; specifically Security Constrained Economic Dispatch. The marginal values associated with various constraints in the optimization problem are called shadow prices. LMP is given by the shadow price of the power balance equations at a location. The energy component is the same for all locations and equal to the system balance shadow price. As explained above, LMP can be decomposed into three components namely energy, loss, and congestion. Congestion component is treated as zero if there are no binding constraints. Loss component is the additional cost due to losses in the line with increment in supply. If there is no congestion and if we are considering DCOPF without any losses, LMP at every bus will be identical and equal to energy component at reference bus. The only reason we need LMP components is the need to use them for FTRs and to split congestion cost from energy cost. Mathematical formulation and calculation of LMP are described in Chapter 2.

As explained in subsection 1.1.2 there are two types of market; Day ahead market and Real time market [5, 52]. Based on forecasted load, LMP is calculated in Day ahead market called "ex-ante LMP". In the Real-time market, every 5 minutes SCED is performed to capture the mismatch in forecasted load and actual load. Besides the calculation of the "ex-ante" LMP, a "post-LMP" calculation will be performed to account for this mismatch. These prices are called "post-LMP" prices. In real world,the post-LMP should be close to the ex-ante LMP since forcasted load is almost same as actual load in most cases. However they need not be same due to a number of reasons, such as load changes, changes of generation offers and demand bids, change of transmission system in the event of outage and maintenance, and change of availability of generators due to outage.

1.1.4 Optimal Power Flow(OPF)

OPF is the technique for optimizing the generation dispatch with multi objectives such as minimizing generation cost, network loss, environmental impact, transmission congestion, maximizing market surplus and so forth, which aims at social welfare. This is subject to several system constraints such as not to violate transmission line thermal limits, voltage magnitude, MVA ratings of the generator, active and reactive power balances, etc. For any OPF, primary goal is to reduce the total cost while satisfying all load requirement and safe operating system constraints. OPF is performed to optimize power system in its steady state. Dynamic stability, transient stability, and contingency cases are generally not addressed in OPF. In real world, OPF solution is implemented into power system by having a control on voltage magnitude and MW production of generator, controlling the voltage level of various buses by using tap changing transformers, MVar control in various buses using Static VAR Compensator (SVC) and other Flexible Alternating Current Transmission System (FACTS) devices.

OPF formulation is classified into AC and DC OPF. Based on the requirements such as convergence tolerance and pace of computation, either one model is used. Due to fast computational speed and better convergence, DCOPF is more popular and is used by several ISOs. However ACOPF gives much more accurate result compared to DC since DCOPF model uses a simplified power flow model without considering reactive power flow and losses in the line. Furthermore, DCOPF uses linear programming model whereas ACOPF is a nonlinear programming model and needs a good initial point to converge the solution. Most of the ISOs [1] including CAISO, MISO, NYISO, ISO-NE, and PJM uses AC power flow or ACOPF in their planning stage. However in real time scenario, PJM, MISO, ISO New England, and NYISO uses DCOPF. Article [39] published by FERC summarizes the manner in which DCOPF and ACOPF are utilized by the RTOs/ISOs at different stages such as Real-Time Economic Dispatch, Real-Time Market Look-Ahead, Residual Unit-Commitment, Day-Ahead Market, Capacity Market, and Planning.

There are several different application of OPF in power systems [45]; such as Real-time electricity price computing, Network congestion management, Electricity transmission fee allocation, Available transmission capability (ATC) computing etc. FERC in [39] quantifies cost savings benefits with improvements of ACOPF. Even 5% improvements in market efficiency due to improvements in OPF results in billions of dollars saving per year. It shows the potential scope of OPF improvements in future.

1.1.5 Distributed Energy Resources

Distributed Energy Resources (DER) are small power sources which are located mostly in distribution network and supplies energy to the grid along with traditional centralized generation. Distributed Energy Resources alters the traditional one way power flow from utility to customers and allows power flow even from low voltage distribution network to high voltage transmission network.

Ackermann in his paper [53], defines DG as "an electric power source connected directly to the distribution network or on the customer site of the meter". In [53], author surveys several different literatures and classifies distributed generation in terms of Purpose, Location, Rating of distributed generation, Power delivery area, Technology, Mode of operation, Environmental impact, Ownership, and Penetration of distributed generation and tries to give a broad definition for DER. DER units consists of distributed generator (DG) and distributed storage (DS). DS is mainly batteries which are used to store energy at certain time and dispatch at a later time. DG's are usually generators either producing AC or DC power and are fed directly to the grid. Table 2.1 shows different DG technologies existing and their existing size. Penetration of more DER into the grid paved way for fast paced modernization and made it easy transition to smart grid. Most of these generators use non-conventional energy sources such as solar energy, wind energy, biomass etc. Paper [34] shows that a distributed generation can be anything that generate power and enlists major technologies used in distributed generation :

- generators powered from renewable energy sources
- co-generation
- standby generators operating grid connected (used when centralized generation is inadequate or expensive)

Distributed generation posses several advantages over traditional generation. Benefits are not only for the utility but also for the customers as well. Customers benefits from better quality of power with dollar savings in a highly competitive market with integration of DG in to the distribution system. Most of these benefits depends on the DG technology used and also the size and location. Several researches have been done to quantify the benefits of including DG in to the system. Compared to traditional centralized generation, the advantages posed by DER are summarized below [6, 9, 10, 20, 27–29, 40, 44, 55]

- Reduction in transmission line losses [9, 10, 44]
- Reduction in transport cost of power [10, 29, 44]
- Improving voltage profile [9, 10, 20, 40, 44]
- Improving system reliability [6, 9, 55]
- Providing spinning reserve for the system [27, 40]
- Providing improved security of supply [27, 29]
- Reducing of fossil fuel sources [29]
- Reducing feeder loading [6]
- Environmental benefits [29]
- LMP improvements in the system [27, 40]

- Peak shaving [6, 10, 27, 44]

- Increasing overall energy efficiency [10, 27, 28, 44]

- Relieving transmission and distribution congestion [10, 27, 40, 44]

However, there are some disadvantages assosciated with inclusion of DER in the distribution network and supplying energy to the grid. Some of the disadvantages as explained in [6] are : Higher energy cost, requires redundancy for equivalent reliability, tequires utility connection for backup power and load following etc. Research [28] shows that penetration of more DG into the system causes small-signal frequency instabilities in distribution systems mainly due to strong electrical interaction between DGs, low damping magnitude of DGs, and low inertia of DGs. Furthermore, research [34] analyses difficulties of including DER into a distribution network.

1.1.6 Transactive Energy

Transactive energy allows the transformation of power system from traditional one-way generation to end-user transmission system to smart grid. [30]. Transactive Energy framework takes it a further step to having a much better participation of distributed generation, improved load management and ancillary services, and intelligent power management system based on market value and economics. Transactive energy is defined by The GridWise Architecture Council's Framework [8] as "A system of economic and control mechanisms that allows the dynamic balance of supply and demand across the entire electrical infrastructure using value as a key operational parameter". Transactive energy [30] allows any party (consumer, producer, or prosumer) to produce, buy, and sell electricity in a reliable, cost efficient and transparent market. Four main benefit of transactive energy listed out by Gridwise Architecture Council are :

- Reliability
- Affordability
- Sustainability
- Efficiency

i Transactive Energy Products

In transactive Energy framework two main products considered essential for any power system are Energy and Transport [51]

- Energy : Electric energy produced by market participants are sold in the form of tenders. This is the cost of producing energy at a particular time. Energy cost varies from time to time and depends on committed units, availability and system load.
- Transport : Consumers have to pay transport cost of energy on top of energy cost from the spot of generation to their location. The energy when transported to different place through a transmission line, it may incur line losses. Based on system load it may create congestion in the system as well. This makes consumers to pay transport cost of energy on top of energy cost.

Hence if a customer wants to purchase power at a given time and place they need to make two tenders with supplier; one for energy and another one for transport.

ii Transactive Energy Markets

In Transactive Energy framework, energy is sold in the form of tenders. Prior to actual sale of energy, electricity sellers sell tenders to buyers. They could sell tenders very well in advance or in real time depending on requirement in power market. The tenders and transactions take place on a Transactive Energy platform either bilaterally or in exchanges. There are two types of markets in the Transactive Energy framework; Forward market and the Spot market [51].

- Forward Market : This market is based on tenders for future delivery of power . Producers use forward market to coordinate investment decisions and to manage risk. It is based on consumer subscription of power and investors way to reduce uncertainty in the revenue cash flow. This allows investors to predict profit very well in advance unlike the traditional centralized generation.

- Spot Market : This market is used to satisfy the need of power in real time. This is used to coordinate operating decisions and to mitigate risk. Everyone in the grid has access to same spot market where they could sell or buy electricity. Spot prices could be higher or lower compared to forward market prices.

In Transactive Energy framework, customers buy tenders of a fixed quantity of energy using forward subscription for a particular point of time.They may use either less or more energy than they actually subscribed. If they use less than what they subscribed they have a option of selling the remaining in spot price. Similarly, if they use more energy than they subscribe, they have to buy the remaining power at spot price. Spot market transactions are used to buy or sell the difference between forward positions and actual demand. It is to be noted that spot price could be higher or lower compared to forward subscription price and depends on energy demand in each location.

1.2 Literature Review

1.2.1 Review of Optimal Power Flow and LMP

The optimal power flow problem has been discussed in power system since its introduction by Carpentier in his paper in 1962 [41]. Prior to Carpentier classical Lagrangian techniques were used for finding OPF but the research then ignored the maximum and minimum limits on optimality functions [39]. Carpentier made use of Kuhn-Tucker conditions to formulate full ACOPF with variable bounds to optimize the system. OPF algorithms can be generally classified into the following three categories: sequential algorithms, nonlinear programming algorithms, and intelligent search methods. Literature survey of the different techniques of optimal power flow are summarized by several authors [22, 31, 41, 42, 45]. Huneault in 1991 [22] surveys most of the publications in the field of optimal power flow existing then and classifies different methods based on optimization techniques. Momoh in 1999, [41] classifies optimization techniques into six categories namely nonlinear programming (NLP), quadratic programming (QP), Newton-based solution of optimality conditions, linear programming (LP), hybrid versions of linear programming and integer programming, and interior point methods. Pandya and Joshi [31], in 2005 did a survey on then existing OPF methods. They are classified as :

- Linear Programming (LP) method
- Newton-Raphson (NR) method
- Quadratic Programming (Qp) method
- Nonlinear Programming (NLP) method
- Interior Point (IP) method
- Artificial Intelligence (AI) methods
- Artificial Neural network
- Fuzzy logic (FL) method
- Genetic algorithm (GA) method.

- Evolutionary Programming (EP)
- Ant Colony Optimization (ACO)
- Particle Swarm Optimization (PSO)

Since the scope of OPF is very vast , it has taken decades to develop efficient algorithms for its solution and is still in research. Generally main objective of most OPF is to minimize generation cost, minimize transmission losses, minimize load shedding schedule, minimize transmission congestion and so on. Several papers [32, 33, 46, 57] also considers interface limits, system spinning reserve, environmental constraints like reduction of NO_x, CO_x, and SO_x emission, and contingency cases as constraints in their optimization.

In Security Constrained OPF (SCOPF), security constraints can be explicitly modeled and added in to the OPF formulation. Some works [32, 33] includes contingency and security considerations while modelling OPF. It is integrated into the OPF function making use of Line Outage Distribution Factor (LODF) and Generator Shift Factor (GSF).

The concept of LMP was first introduced by F.C. Schweppe in 1988 in his book *Spot Pricing of Electricity* [17]. It was mostly based on spot pricing of power. However, the LMP mechanism was later published for the first time by Dr. William Hogan in 1992 [21], where he calculates price using a centralized dispatch mechanism considering marginal cost of generation and system constraints. Several researches uses different models to calculate LMP at different buses. Yong Fu and Zuyi Li in [18], shows different models for calculating LMP. Research [18] also shows that LMP could be higher than the cost of highest generator or lower than cheapest generating unit due to congestion in the transmission line. Research [35] compares LMP calculation based on DCOPF and ACOPF and shows the cases where LMP results are very close to each other and the cases where LMP are different. The conditions affecting difference in LMP in ACOPF and DCOPF are also described in this paper.

ISO recommends that the LMP is to be calculated as cost of energy, losses, and transmission line congestion. However some works [32, 33] doesn't consider cost for power losses in the line as they consider DCOPF for optimizing the system. Several ISOs [7,12,37] explains how they calculate LMP for their customers in their area of operation. New England ISO [37] calculates LMP based on shadow prices of Linear Programming solution. LMP could be split into three components namely

Energy, Congestion, and Losses. [37] explains the mathematics behind LMP calculation. PJM ISO also describes calculation of LMP based on these three components in their manual [12].

1.2.2 Review of Distributed Energy Resources

Integration of Distributed Energy Resources into an existing utility can result in several benefits. These benefits include line loss reduction, reduced environmental impacts, peak shaving, price hedging, fuel switching, improved power quality and reliability, increased overall energy efficiency, relieved transmission and distribution congestion, voltage support, and deferred investments to upgrade existing generation, transmission, and distribution systems. Several studies have been done in this regard portraying the benefits of DG [6,9,10,13,19,20,25–28,28,29,36,38,40,43,44,50,55,58]

Several research [10, 44] have done showing line loss reduction by inclusion of DG into the transmission system. Chiradeja [44] in his paper, investigates the line loss reduction benefits by addition of DG into a transmission network. He showed that, there is considerable reduction in line loss by considered a simple case of radial distribution line with concentrated load at one end and source in the other end and with inclusion of a DG in between. The authors of [6,55] presented DG installed as a backup generator and is quantified the improvements in the reliability indices. In [29] the environmental benefits of DG has been quantified by using environmental benefits indices.

Several authors [13, 20, 28, 58] have studied the effects of distributed generators on dynamic stability of power systems. These studies has been analyzed in many references with different approaches. Reference [13] addresses the bulk transmission system transient and small-signal stability of distributed utilities. The author of [20] evaluated the impact of inertia of distributed energy resources on tranmission grid using transient stability and small signal stability. N Hidayatullah [43] investigated the system stability after installing distributed generation in the Smart Grid. Cardell [25], studied eigen analysis of the instability and block diagonal dominant structure analysis of system matrix to study frequency instability in the primary dynamics of the distributed generators. In addition, Cardell [25] have analysed the frequency performance and dynamic stability of distribution systems which have multiple small scale distributed generators. The author further investigates the engineering and market integration of DG into the distributed system.

Researches [36, 38]have been done regarding how to integrate microgrids and distributed generators into grid using optimization techniques. In [36], an optimization model of economic dispatch for distributed system is established by integrating problems, such as the scheduling of generators, intelligent management of energy storage units and optimization of operated efficiency of the network, into a uniform optimization problem. Mahmoodi [38] in his paper, introduces the concepts of distributed economic dispatch system for microgrids. He shows a way to independently schedule power and energy exchange for every storage system in the grid. This gives a lot of technical benefits for real time power management by these distributed units. Research [9, 50] have been done showing the optimal placement and sizing of DG in system for maximum social welfare. Here distributed generators with different cost function are considered and are investigated for optimal placement and size, to maximize social welfare. Momoh investigated the impacts of DG on the power system using LMP [27,40]. In [27], the marginal price contribution of DG to power network is shown for different loading and system contingencies. He compares LMP at different buses before and after addition of DG into the system with several different system cases such as keeping utility generation fixed, contingencies, and loss of generation. In most of these cases LMP got improved with inclusion of DG into the system. In [27], the author presented an effective implementation of DG in a partitioned system and its impacts on system-wide Voltage Stability Margin and LMP distribution.

Several works shows modeling DG as a negative load to system. Some authors models model DG as a normal generator with cost characteristic similar to utility generator [9]

1.2.3 Review of Transactive Energy

"Transactive Energy: A Sustainable Business and Regulatory Model for Electricity" [51] by Stephen Barrager and Edward Cazalet is pioneer in explaining most of the concepts of transactive energy and analysing a detailed business model for Transactive Energy Framework. The book explains transactive energy based on three fundamental systems:

- Physical system
- Transaction system
- Regulatory system

The physical system is the existing power system with energy generation, storage, transmission, and distribution. The transaction system involves power exchanges, market making, arbitrage, hedging, and financial services. The regulatory system safeguards against economic abuse, rule violation, and oversees safety and reliability. Transaction system is based on two markets which is explained in details in this book [51]; Forward Market and Spot Market. There are several other works including the literature from GridWise Architecture Council [4, 8, 49] that speaks about spot market and forward market. Gridwise published Transactive Energy framework [8] where fundamental ideas of Transactive Energy are discussed. Here current status of Transactive Energy Framework, Analysis of Transactive Energy behaviour in grid, and Future work in transforming present grid into Transactive Energy environment are discussed. There are several other works [4,49] describing the fundamentals of Transactive Energy, and policies which lead a path to achieve the Transactive Energy market.

Research [49] shows the costs and benefits of adding renewables into the grid on a Transactive Energy Framework. This paper also shows the energy benefits for utilities in Forward Market and Spot Market. However the benefits are not quantified in terms of dollar value for utilities. The amount of energy purchased, analysis of benefits from the point of reliability of the system, and dollar savings from consumer payment are not analyzed here. This thesis deals mainly with aforementioned topics in transactive energy framework.

1.3 Scope of Work

Some of the utilities may not be able to meet its entire load demand in real time either due to insufficient generation or due to transmission line congestion. This could lead to load shedding if the lacking power is not supplied from neighboring utilities. In real time, load shedding causes substantial loss for utility in terms of financial penalties. If there is sufficient distributed generation, the system operator could meet the load demand by dispatching them. The purpose of this work is to address aforementioned issue and to propose a method that analyzes power transactions between distributed generation and utility generation to minimize load shedding and to maximize utility profit.

To develop the method of load shedding minimization that includes distributed generation for profit maximization, the following steps have been completed:

- A literature review on distributed generation, optimization techniques, pricing of electricity, and power markets as well as transactive energy.

- A thorough study of mathematical representation of an appropriate optimization method and pricing scheme to be used.
- An investigation and selection of test cases for simulation of the proposed method.
- Simulation of selected test systems.
- An analysis of the simulated results to verify the benefits of the proposed method.

As a result, utilization of distributed generation to reduce load shedding in a power system during peak hours of the day is proposed. Two test systems – a 6-bus system and modified IEEE 14-bus system – were selected for this study. Transactive Energy framework with power transactions in forward and spot market were incorporated into the test systems. An algorithm to minimize load shedding and to maximize utility profit by optimizing the purchase of power from distributed generation was developed based on AC Optimal Power Flow (ACOPF).

The developed algorithm performs optimization on multiple objective functions with the main objective of minimizing total load shedding and other objectives including minimizing total cost of production. The algorithm contains three main steps namely *Power System Optimization, Energy price Calculation, and Transactive Accounting.* The proposed algorithm is implemented on a Transactive Energy framework with forward and spot market analyzed to quantify the utility benefits obtained by purchasing power from distributed generation.

The software that implements the proposed algorithm was developed in MATLAB using an open source package MATPOWER. Both six bus system and modified IEEE fourteen bus system were simulated using the software. Three metrics were developed to represent the benefits of the algorithm and are presented in detail in Chapter 5.

Chapter 2

Mathematical Formulation

The chapter gives various mathematical formulation used for developing the thesis methodology in Chapter 3. This work uses the AC Optimal power flow to calculate the generator dispatch in in various markets. Various concepts used in Optimal Power flow such as unit commitment, ACOPF, Security constrained OPF and its various constraints are explained first. The pricing mechanism used in this work is LMP. The LMP calculation and various factors associated with it is explained next. Finally, the model of distributed generator and consumer payment formulation is introduced. The various expressions outlined here are later used in Chapter 3 to develop the mathematical formulation of this work.

2.1 Optimal Power Flow

A general optimization problem is to minimize an objective function subject to certain constraints. It can be written as:

$$\text{Minimize: } J = f(x) \qquad \text{the objective function} \tag{2.1}$$

$$\text{subject to: } h_i(x) = 0, \quad i = 1, 2, ..., m; \qquad \text{'}m\text{' number of equality constraints} \tag{2.2}$$

$$g_i(x) \leq 0, \quad i = 1, 2, ..., n; \qquad \text{'}n\text{' number of inequality constraints} \tag{2.3}$$

Usually objective function $f(x)$ has just one objective to minimize and mostly it is the total cost of generation. However, it can have multiple objectives such as minimization of transmission losses, minimization of Carbon emissions, maximizing social welfare and so forth. Total generation to match the total load plus the losses in the line is the main equality constraint in most of the OPF. Inequality constraints are mostly the maximum and minimum limits on the voltage and angle at different buses, real and reactive power generation limits and so on.

2.1.1 AC Optimal Power Flow

Optimization vector x for standard AC OPF [59] consists of four variables given by Equation 2.4.

$$x = \begin{bmatrix} V_m \\ \theta \\ P_g \\ Q_g \end{bmatrix} \tag{2.4}$$

Here V_m and θ are the voltage magnitude and angle at different buses and have same size as number of buses in the test case n. P_g and Q_g are the real and reactive power generation by different generator installed and have size equal to total number of generators n_g. Unlike DC OPF, where only P_g and θ are considered, AC OPF considers all four variables of objective vector x. Hence objective function is to minimize the total cost of real power P_g and reactive power Q_g given by Equation 2.5.

$$\text{Minimize: } J = \sum_{i=1}^{n_G} P_G(i) \times C_i\big(P_G(i)\big) + Q_G(i) \times C_i\big(Q_G(i)\big) \tag{2.5}$$

$$\text{subject to: } \sum_{i=1}^{n_G} P_G(i) = P_L(i) + P_{LOSS} \tag{2.6}$$

$$\sum_{i=1}^{n_G} Q_G(i) = Q_L(i) + Q_{LOSS} \tag{2.7}$$

$$\forall P_G^{min}(i) \leq P_G(i) \leq P_G^{max}(i) \tag{2.8}$$

$$\forall Q_G^{min}(i) \leq Q_G(i) \leq Q_G^{max}(i) \tag{2.9}$$

$$\forall V^{min}(i) \leq V(i) \leq V^{max}(i) \tag{2.10}$$

$$\forall F_k \leq F_k^{max} \tag{2.11}$$

where,

$C_i\left(P_G(i)\right) =$ Average marginal cost for active power $(\$/MW)$ of generator i

$C_i\left(Q_G(i)\right) =$ Average marginal cost for reactive power $(\$/MVar)$ of generator i

$P_G(i) =$ MW Output of generator i

$Q_G(i) =$ MVar Output of generator i

$P_L(i) =$ Total MW Load at bus i

$P_{LOSS} =$ Total MW loss in transmission lines

$Q_L(i) =$ Total MVar Load in bus i

$Q_{LOSS} =$ Total MVar loss in transmission lines

$P_G^{max}(i) =$ Maximum MW output capacity of generator$i$

$P_G^{min}(i) =$ Minimum MW dispatch of generator i if turned on

$Q_G^{max}(i) =$ Maximum MVar output capacity of generator$i$

$Q_G^{min}(i) =$ Minimum MVar dispatch of generator i if turned on

$V(i) =$ Voltage at bus i

$V^{max}(i) =$ Maximum voltage limit at bus i

$V^{min}(i) =$ Minimum voltage limit at bus i

$F_k =$ Power flow through the transmission line k

$F_k^{max} =$ Maximum power flow limit through the transmission line k

$i =$ Generator Index,i.e., i=1,2,3,...,N

2.1.2 Unit Commitment

Unit Commitment is process of optimizing the system considering generator operating cost. Here we shut off generators with higher operating cost and is turned only rest of the generators are not able supply required power to the load. In AC OPF, generators are always set to run in its minimum generation limit irrespective of the ability for the operator to shut off completely. If unit commitment is considered as the only way to optimize system, transmission constraints are generally not considered. Work done in [32, 33], which is based on DCOPF, presents mathematical representation of unit commitment given by Equation 2.12-2.15.

$$\text{Minimize: } J = \sum_{i=1}^{n_G} \Big[P_G(i) \times C_i\left(P_G(i)\right) \times I(i) + S(i) \Big] \tag{2.12}$$

$$\text{subject to: } \sum_{i=1}^{n_G} P_G(i) I(i) = P_L(i) + P_{LOSS}(i) \tag{2.13}$$

$$\sum_{i=1}^{n_G} r_s(i) I(i) \geq R_s \tag{2.14}$$

$$P_G(i) \leq P_G^{max}(i) \tag{2.15}$$

where,

$C_i\left(P_G(i)\right) =$ Average marginal cost $(\$/MW)$ of generator i

$P_G(i) =$ Output of generator i

$I(i) =$ Commitment state (on = 1 or off = 0) of generator$i$

$S(i) =$ Start-up cost of generator$i$

$r_s(i) =$ Spinning reserve contribution from generator i

$R_s(i) =$ System spinning reserve requirement in the commitment period

$i =$ Generator Index,i.e., i=1,2,3,...,N

2.1.3 Security Constrained Optimal Power Flow

Security Constrained Optimal Power Flow (SCOPF) is the process of optimizing the total operating cost of the system serving market demand and considering security constraints of the system. Researches [32, 54] show the mathematical calculation for optimization and constraints considered while calculating SCOPF. The objective function used here is similar to the AC OPF in subsection 2.1.1. The main objective is to minimizes the total system production cost J. It is given mathematically below:

$$\text{Minimize: } J = \sum_{t=1}^{T}\sum_{i}^{n_G}\Big[\Big(P_G(i,t)\times C_i(P_G(i,t)) + Q_G(i,t)\times C_i(Q_G(i,t))\Big)\times I(i,t) + S(i,t)\Big] \tag{2.16}$$

where,

$C_i\,(P_G(i,t))$ = Generator cost function for active power (\$/MW) of unit i

$C_i\,(Q_G(i,t))$ = Generator cost function for reactive power (\$/MVar) of unit i

$I(i,t)$ = Commitment state of unit i at time t

$S(i,t)$ = Start-up cost of generator i at time t

SCOPF is subjected to the following constraints:

i System Real and Reactive Power Balance

This is an equality constraint and balances the demand and supply

$$\sum_{i=1}^{n_G} P_G(i,t)\times I(i,t) = P_D(t) \tag{2.17}$$

$$\sum_{i=1}^{n_G} Q_G(i,t)\times I(i,t) = Q_D(t) \tag{2.18}$$

where $P_D(t)$ and $Q_D(t)$are the MW demand and MVar demand at time t.

ii System Spinning Reserve Requirement

This constraint set the minimum spinning reserve for each generator in operation.

$$\sum_{i=1}^{n_G} r_s(i,t)\times I(i,t) \geq R_s \tag{2.19}$$

where $r_s(i,t)$ is spinning reserve contribution from unit i at time t. R_s is the system spinning reserve requirement in the commitment period.

iii Unit Operating limits

$$P_G^{min}(i,t) \leq P_G(i,t) \leq P_G^{max}(i,t) \tag{2.20}$$

$$Q_G^{min}(i,t) \leq Q_G(i,t) \leq Q_G^{max}(i,t) \tag{2.21}$$

iv Transmission line flow limits

$$\forall F_k \leq F_k^{max} \tag{2.22}$$

where, F_k is the power flow through the transmission line k and $F_k^{max}(p,q)$ is the maximum power flow limit through the transmission line k

v Interface flow limits

$$\underset{n_{IL}}{\overset{IL=1}{\forall}} \sum_{k=1}^{n_L} F_k \leq P_{IL}^{max} \tag{2.23}$$

IL is the interface index and k is the line index that composed an interface. n_L is the number of lines in the interface IL.

vi Contingency Constraints

Reliability Council of the country, NERC requires the power system to be withstand atleast N-1 contingency i.e, the power system to be secure with one or more elements out of service. Power system withstanding contingency constraint is another requirement of SCOPF.

vii Environmental Constraints

$$\sum_{t=1}^{T} \sum_{i=1}^{n_G} C_{ei}\Big(P_G(i,t)\Big) \times I(i,t) \leq EL \tag{2.24}$$

where C_{ei} is the unit emission at output level P_G over time T for all units n_G dispatched should be less than the overall emission limit EL in the commitment period.

2.2 Calculation of LMP

2.2.1 Generator Shift Factor

Generator Shift Factor or GSF is the increase in flow at a particular transmission line that results from an injection of power at a bus. It describes a generator's impact on a flowgate. It is the ratio of change in power flow of line k (power flow from bus p to bus q) to change in injection of power at bus i [32].

$$GSF_{k,i} = \frac{z_{pi} - z_{qi}}{Z_{pq}} \tag{2.25}$$

Based on the above equation, the GSF for the entire system can be represented in a matrix form as follows.

$$GSF = \begin{bmatrix} GSF_{11} & GSF_{12} & GSF_{13} & \dots & GSF_{1N} \\ GSF_{21} & GSF_{22} & GSF_{23} & \dots & GSF_{2N} \\ \vdots & \vdots & \vdots & \ddots & \vdots \\ GSF_{M1} & GSF_{M2} & GSF_{M3} & \dots & GSF_{MN} \end{bmatrix}_{M \times N} \tag{2.26}$$

$GSF_{k,i}$ = Generator shift factor representing the current change on line k with respect to the current injection at bus i

N =Number of buses

M =Number of transmission lines

2.2.2 Loss Factor and Delivery Factor

The Loss Factor (LF) at the i th bus may be viewed as the change of total system loss with respect to a 1 MW increase in injection at that bus [5, 35, 37]. It is given as Equation 2.27

$$LF(i) = \frac{\partial P_{Loss}}{\partial P_i} \tag{2.27}$$

$LF(i) =$ loss factor at bus i

$P_{Loss} =$ Total transmission line loss

$P_i =$ Total injected power at bus i

The Delivery Factor (DF) at the ith bus represents the effective MW delivered to the customers to serve the load at that bus. It is defined as Equation 2.28

$$DF(i) = 1 - LF(i) = 1 - \frac{\partial P_{Loss}}{\partial P_i} \tag{2.28}$$

Penalty Factor (PF) at each bus i is given by the following equation (Equation 2.29)

$$PF(i) = \frac{1}{1 - LF(i)} = \frac{1}{DF(i)} \tag{2.29}$$

Loss Factor and Delivery Factor of the system can be calculated based on GSF of the system [5]. P_{LOSS} is basically the heat loss in the transmission system and can be represented using Equation 2.30

$$P_{LOSS} = \sum_{k=1}^{M} F_k^2 \times R_k \tag{2.30}$$

where,

$P_{LOSS} =$ Total transmission line loss

$M =$ Total number of transmission lines

$F_k =$ Line flow of line k

$R_k =$ Resistance of line k

Combining Equation 2.27 and Equation 2.30 gives that total transmission line loss can be represented using power flow in each line and resistance of corresponding line. (Equation 2.32)

$$LF(i) = \frac{\partial P_{Loss}}{\partial P_i} = \frac{\partial}{\partial P_i}\left(\sum_{k=1}^{M} F_k^2 \times R_k\right) \tag{2.31}$$

$$= \sum_{k=1}^{M} 2F_k \times R_k \times \frac{\partial F_k}{\partial P_i} \tag{2.32}$$

Line flow F_k can be represented using GSF as Equation 2.33

$$F_k = \sum_{j=1}^{N} GSF_{k,j} \times P_j \tag{2.33}$$

Applying Equation 2.33 in Equation 2.32 gives the simplified expression for Loss Factor.

$$LF(i) = 2 \times \sum_{k=1}^{M} \left(GSF_{k,i} \times R_k \times (\sum_{j=1}^{N} GSF_{k,j} \times P_j) \right) \tag{2.34}$$

2.2.3 Line Outage Distribution Factor

LODF approximate the change of branch power flow depending on the outage of another branch.This factor represents the change of power flow in the line p when the outage of line q occurred.Papers [32, 48] explains the calculation of LODF. LODF can be mathematically represented as:

$$LODF_{p,q} = \frac{\Delta P_p^q}{P_q^0} \tag{2.35}$$

where ,

$LODF_{p,q}$ =Line outage distribution factor representing the current change on line p with an outage of line q

p =Transmission line where LODF is calculated

q =Transmission line where there is an outage

ΔP_p^q =Change of power flow in the line p when the outage of line q occurred

P_q^0 =Real power flow in the line q before outage

LODF can represented in terms of impedences of the transmission lines as follows:

$$LODF_{p,q} = \frac{Z_q}{Z_p} \frac{(z_{jm} - z_{jn}) - (z_{km} - z_{kn})}{Z_{th,q} - Z_q} \tag{2.36}$$

where ,

Z_p = Impedance of line p (line jk)

Z_q = Impedance of line q (line mn)

$Z_{th,q}$ = Thevenin impedance of line q (line mn) $= z_{mm} + z_{nn} - 2z_{mn}$

z_{ab} = Impedance between buses a and b

This could be simplified in terms of GSF as goven below :

$$LODF_{p,q} = \frac{GSF_{im} - GSF_{in}}{\dfrac{z_{mm} + z_{nn} - 2z_{mn}}{jx_{mn}} - 1} \tag{2.37}$$

where,

GSF_{ab} = Generator shift factor representing the current change on line a with respect to the current injection at bus b

x_{mn} =Imaginary part of line reactance between buses m and n (line q)

2.2.4 Locational Marginal Pricing

PJM shows the calculation of LMP in real time environment in their Operating Agreement Accounting Manual [12].While calculating LMP they considers three components; namely energy price, loss price, and congestion price at each bus. Energy cost is the market sellers offered price on a reference bus. Losses in the transmission line account for Loss Price. If we consider a lossless line, this term can be treated as zero.

$$LMP(i) = \lambda - \sum \Big[A(i,k)\big(SP(k)\big)\Big] + \lambda\left(\frac{1}{PF(i)} - 1\right) \tag{2.38}$$

where,

$LMP(i)$ = the Locational Marginal Price at bus i

λ = the system marginal price of generation at the reference bus

$A(i,k)$ = the sensitivity for bus i on binding constraint k

$SP(k)$ = the shadow price of constraint k

$PF(i)$ = the penalty factor for resource i

LMP can be decomposed as

$$LMP(i) = LMP_{energy}(i) + LMP_{congestion}(i) + LMP_{loss}(i) \tag{2.39}$$

LMP decomposition can be mathematically represented as follows :

$$LMP_{energy}(i) = \lambda = \text{price of Energy at a reference bus} \tag{2.40}$$

$$LMP_{congestion}(i) = -\sum_{k=1}^{M} GSF_{k,i} \times \mu_k \tag{2.41}$$

$$LMP_{loss}(i) = \lambda \times (DF_i - 1) \tag{2.42}$$

where μ_k is the constraint cost or shadow price of line k, defined as:

$$\mu_k = \frac{\text{change in total cost}}{\text{change in constraint's flow}} \tag{2.43}$$

$$\tag{2.44}$$

By substituting the expression for delivery factor (Equation 2.28), in expression for LMP_{loss} we get a new expression for loss component of LMP. (Equation 2.46)

$$LMP_{loss}(i) = \lambda \times \big((1 - LF(i)) - 1\big) \tag{2.45}$$

$$= -\lambda \times LF(i) \tag{2.46}$$

Combining Equation 2.46 and Equation 2.34 gives new expression for loss component of LMP at bus i.

$$LMP_{loss}(i) = -\lambda \times 2 \times \sum_{k=1}^{M} \Big(GSF_{k,i} \times R_k \times (\sum_{j=1}^{N} GSF_{k,j} \times P_j) \Big) \tag{2.47}$$

Energy and congestion component of LMP are calculated based on SCOPF mentioned in subsection 2.1.3. Research works in [32,33,54] show detailed procedure of LMP calculation. SCOPF gives the security of a generation pattern considering several constrains explained in subsection 2.1.3 . Even if the system is secure, several transmission lines and interfaces may operate close to or at its limit. Transmission lines and interfaces which are close to its limit are called binding constraint. LMP is calculated as the incremental cost of next MW of power at a particular bus. For this, it is necessary to find out which generator will be contributing for next MW of power. If binding constraints are detected, LMP calculation can be very different since incremental MW of power could be from a very different set of generators. Without binding constraints, all bus prices are the same and equal to the marginal cost of the generator that is the last unit to dispatch. The binding constraints are what defines LMP and make bus prices different.

Work done in [32], shows that LMP can be calculated based on incremental flow equation and incremental price equation. Incremental flow equation which determines how much each generator will contribute to serve next MW increase of load at a given bus is calculated first. Next the Incremental Price Equation which determines the nodal price at every bus is calculated, which is the weighted product of generator contribution (from incremental flow equation) and their unit marginal cost. Incremental Flow equation for bus i can be mathematically represented as follows:

$$\forall k \in B_c : \sum_{j}^{n_G} GSF_{k,j} \times \Delta P_G(j) = GSF_{k,i} \tag{2.48}$$

$$\sum_{j}^{n_G} \Delta P_G(j) = 1 \tag{2.49}$$

where,

$$\Delta P_G(j) = \text{Contribution by generator at bus } j$$

$$k = \text{Trasmission line (or interface) that has a binding constraint}$$

$$j = \text{Bus where a generator is located}$$

$$B_c = \text{A set of binding constraints}$$

The generator contribution at each bus (ΔP_j) is calculated by solving linear equations given above (Equation 2.49). However, when a binding constraint k is an interface of two or more transmission lines, $GSF_{k,j}$ in the above equation is the composite generator shift factor, which is the sum of generator shift factors of bus j on all the transmission lines that are part of the interface. Similarly, the composite generator shift factor $GSF_{k,i}$ of bus i on all the transmission lines that are part of the interface is needed on the right hand side of the equation when k is an interface of two or more lines.

ΔP_j is then used in incremental price equation to calculate LMP at every bus. Incremental price equation is given by Equation 2.50

$$LMP_{E,C}(i) = \sum_{j}^{n_G} \Big(\Delta P_G(j) \times UMC(j)\Big) \tag{2.50}$$

where,

$$LMP_{E,C}(i) = \text{Energy and Congestion components of LMP at bus } i$$

$$UMC(j) = \text{Unit marginal cost of generator at bus } j$$

2.3 Model of Distributed Generator

Momoh in his work [27], shows that DG can be modeled as a generator with fixed real and reactive power. He shows that DG can be assumed to behave as a ZIP load. He classifies the model of DG into three broad categories.

1. Synchronous Condensers : to increase the energy margin and to provide system stability.

2. Induction Generators : to maintain constant voltage.

Technology	Typical available size per module
Combined cycle gas Turbines	35–400 MW
Internal combustion engines	5 kW–10 MW
Combustion turbine	1–250 MW
Micro-Turbines	35 kW–1 MW
Small hydro	1–100 MW
Micro hydro	25 kW–1 MW
Wind turbine	200 Watt–3 MW
Photovoltaic arrays	20 Watt–100 kW
Solar thermal, central receiver	1–10 MW
Solar thermal, Lutz system	10–80 MW
Biomass, e.g. based on gasification	100 kW–20 MW
Fuel cells, phosacid	200 kW–2 MW
Fuel cells, molten carbonate	250 kW–2 MW
Fuel cells, proton exchange	1 kW–250 kW
Fuel cells, solid oxide	250 kW–5 MW
Geothermal	5–100 MW
Ocean energy	100 kW–1 MW
Stirling engine	2–10 kW
Battery storage	500 kW–5 MW

Table 2.1: Various Technologies for distributed generation. Source : [53]

3. UPS with Grid Inter-tie : to serve as battery backup.

In [53], different technologies for distributed generation are described. The author classifies DG technologies varying from few KW to several hundred MW. Table 2.1 shows the available technologies for distributed generation. Wide varieties of DG technologies with varying operating characteristics are available in the market.Table 2.2 shows some of the cost characteristics of DG used in research work [9]. Cost characteristics used in this work are from Table 2.2.

DG ID	a	b	c
DG 1	0.002	15	0
DG 2	0.004	19	0
DG 3	0.04303	20	0
DG 4	0.25	20	0
DG 5	0.1	30	0
DG 6	0.01	40	0
DG 7	0.003	43	0

Table 2.2: Cost characteristics of distributed generators

2.4 Consumer Payment

Consumer Payment (CP) is the product of LMP at a particular bus with total load at that bus [9]. CP represents the total amount the consumer pays at a given bus to the supplier of power. It also represents the total amount ISO collects from consumers. CP can be mathematically represent as the product of $LMP(i)$ and $P_L(i)$ given by Equation 3.1.

$$CP(i) = LMP(i) \times P_L(i) \tag{2.51}$$

$$CP = \sum_{i=1}^{N} CP(i) = \begin{bmatrix} CP(1) \\ CP(2) \\ CP(3) \\ \vdots \\ CP(N) \end{bmatrix} \tag{2.52}$$

where,

$CP(i) =$ Consumer payment at bus i

$LMP(i) =$ Locational Marginal Price at bus i

$P_L(i) =$ Total load at bus i

$CP =$ Total Consumer Payments from all buses

$N =$ Total number of buses

Usually as demand goes high, price of Electricity at that particular bus also goes high. So consumer payment is one of the index in choosing best location for installing additional generation. But often, price could be small but load could be relatively high or price could be relatively high and load is low. In both cases CP reflects the total payments to ISO by costumers. So ranking them gives the optimal location for placing additional generation often, Distributed Generation to reduce consumer payment. Paper [9] calculates CP at every bus and identifies the best location for placement of DG.

Chapter 3

Methodology

This chapter discusses the proposed methodology for including distributed generation in addition to traditional utility generation under transactive energy market simulations that minimize the fuel costs and load shedding.According to transactive energy framework described in chapter 1, subsection 1.1.6, there are two types of markets, forward and spot market. Benefits of including distributed generation in the market are accounted using the calculations done under different market scenarios. An overview of the proposed methodology, its algorithm, and procedures are presented in Figures 3.1-3.4. Algorithms developed in this work is depicted in Figure 3.1 and contain three main steps namely *Power System Optimization, Energy-price Calculation, and Transactive Accounting* described in detail in the following sections. Power System Optimization is explained in section 3.1 and , Energy-price Calculation in section 3.3, and Transactive Accounting in section 3.4 respectively. In section 3.1, forward transaction optimization technique is proposed along with calculation for maximum forward subscription tenders. Next in section 3.2, the optimization that allows purchasing power from distributed generation to minimize load shedding is proposed. The proposed algorithm is a multi-objective optimization with main objective to maximize utility profit by minimizing overall cost of production, load shedding, and purchase of power from distributed generator. Section 3.3 describes the methodology to calculate cost of power in forward and spot markets. This corresponds to step 2 in Figure 3.1. Finally in section 3.4, step 3 of Figure 3.1 is described where production cost and consumer payments are calculated to account for utility transactions in forward and spot market. Step 3 quantifies the benefits of including distributed generation along with utility generation in transactive energy framework. Various other calculations used in this work are also described in subsequent sections. Software has been developed using MATPOWER and MATLAB based on the aforementioned algorithm.

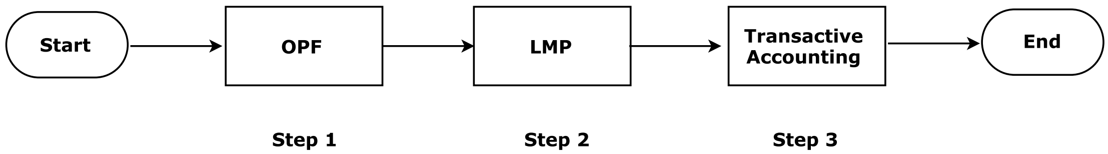

Figure 3.1: Methodology used in this work.

3.1 Forward Transaction Optimization

In transactive energy business model, forward transaction brings risk free transactions for both sellers and buyers. Buyers buy the tenders from utility, way before the the actual transaction happens. Utilities are obliged to deliver power to customers who make tenders in forward transaction. The system operator monitors the tendering process and allows utilities to make tenders only if they are capable of delivering the requested power at a given point of time and place. In this section, an algorithm for forward transaction optimization is proposed which calculate maximum tenders utility can make with customers. Load shedding is necessary for the areas where the utility is not capable of delivering power during the optimization process. The algorithm to optimize the forward positions and the forward transaction tendering calculations are presented in the forthcoming subsection.

3.1.1 Optimal power flow and load shedding calculation

An optimal power flow is carried out to calculate the maximum load an utility can serve during each hour of the day. The objectives of this security constrained optimization are minimizing total cost of production and load shedding, subjected to several system constraints. Max Thimum load the seller is able to make tender is calculated first and in section 3.4 corresponding consumer payment is calculated to account for profit/loss of each transaction. An AC optimal power flow with standard Newton Raphson technique is used for optimization calculations. MATPOWER computes the optimal power flow by calculating the mismatch $g(x)$ in each step, forming the Jacobian based on the sensitivities of these mismatches to changes in x and solving for an updated value of x by factorizing this Jacobian. e optimization of system based on security constraints is done similar to SCOPF described in chapter 2, subsection 2.1.3. The mathematics behind the optimization function is presented below.

$$\text{Minimize:} \quad (i)\ J = \sum_{i}^{n_G} \Big[\big(C_i(P_{UG}(i)) + C_i(Q_{UG}(i))\big) \times I_{UG}(i) + S(i) \Big] \tag{3.1}$$

$$(ii)\ P_{LS}^{tot} = \sum_{i=1}^{N} P_{LS}(i) \tag{3.2}$$

$$\begin{aligned}
\text{subject to:} \quad & \sum_{i}^{n_G} P_{UG}(i) \times I_{UG}(i) = \sum_{i=1}^{N} P_L(i) \\
& P_{UG}^{min}(i) \leq P_{UG}(i) \leq P_{UG}^{max}(i) \\
& Q_{UG}^{min}(i) \leq Q_{UG}(i) \leq Q_{UG}^{max}(i) \\
& V^{min}(i) \leq V(i) \leq V^{max}(i) \\
& \forall F_k \leq F_k^{max} \\
& \overset{n_{IL}}{\forall} \sum_{k=1}^{n_L} F_k \leq P_{IL}^{max}
\end{aligned}$$

where,

$J =$ Objective function to minimize the total cost of generation

$P_{LS} =$ Total load shedding in MW

$n_G =$ Total number of generators

$N =$ Total number of buses

$C\,(P_{UG}(i)) =$ Average marginal cost (\$/MW) of generator i

$C\,(Q_{UG}(i)) =$ Average marginal cost for reactive power (\$/MVar) of generator i

$I_{UG}(i) =$ Commitment state of utility's generation unit i

$S(i) =$ Start-up cost of generator i

$P_{UG}(i) =$ MW Output of generator i

$Q_{UG}(i) =$ MVar Output of generator i

$P_L(i) =$ Total Load demand at bus $iincludinglossintransmission$

$P_{UG}^{max}(i) =$ Maximum output capacity of generator$i$

$P_{UG}^{min}(i)$ = Minimum dispatch of generator i if turned on

$V(i)$ = Voltage at bus i

$V^{max}(i)$ = Maximum voltage limit at bus i

$V^{min}(i)$ = Minimum voltage limit at bus i

F_k = Power flow through the transmission line k

$F_k^{max}(p,q)$ = Maximum power flow limit through the transmission line k

IL = Interface limit

n_{IL} = Number of interface limits

The objective of the optimization is to minimize the total system production cost and load shedding with the following constraints.

- System real power balance :This is an equality constraint and balances the load demand with supply.
- Unit operating limits: All generators committed must operate within their physical operational limits.
- Bus voltage limits: Voltage magnitude at all buses should be within their alloted limits.
- Transmission line limits flow limits: The power flow in each transmission line must be less than thermal limits of the line.
- Interface limits: For each interface in the grid, the sum of power flow in the transmission lines that make up of the interface must be less than or equal to the interface limit.

The forward transaction optimization algorithm is made to run for each hour of the day with system load expected as the maximum load in forward position.The solution is the generation outputs that obey the generation and load balance constraint and fulfill the transmission limits specified. The output of these calculations are optimal power flow solution and a map showing various bus load shedding. If $P_L(i)$ is expected load at bus i at a given time and if $P_{LS}(i)$ is minimum load shedding calculated from the aforementioned algorithm, maximum load in forward subscription is calculated using the following expression(Equation 3.3).

$$P_L^{FS}(i) = P_L(i) - P_{LS}(i) \tag{3.3}$$

where,

$$\begin{aligned} P_L^{FS}(i) = & \text{ Load in Forward transaction at bus } i \\ P_L(i) = & \text{ System load expected at bus } i \\ P_{LS}(i) = & \text{ MW Load Shedding at bus } i \end{aligned}$$

Total forward subscription (FS) load is calculated by summing FS load at every hour for a 24 hour time period.

$$P_L^{FS} = \sum_{t=1}^{T}\sum_{i=1}^{N} P_L^{FS}(i,t) \tag{3.4}$$

$$P_L^{FS} = \sum_{t=1}^{T}\sum_{i=1}^{N} \Big(P_L(i,t) - P_{LS}(i,t)\Big) \tag{3.5}$$

Figure 3.2 depicts the steps in optimization process for each operational period. The program uses Linear Programming (LP) to solve the optimization problem. Flow chart depicted in Figure 3.2 shows the actual program flow and the algorithm used for optimization.The program first loads the case file with all system parameters in it. Next, the expected P and Q load is estimated for given time t and determines the path of optimization to follow (forward transaction or spot market). Interface limits and its location is explicitly added into the case file and turned on before passing the case file into optimization block. It uses Newton Raphson technique to solve the minimization function. If there exist a solution, the LP converges with all constraints satisfied and minimum production cost derived; the results are then saved before passing into the next section. If the LP do not converge, recommitment of generating units are performed and LP process repeats with different set of units committed until LP converges. However, if the available generation resource is not sufficient to satisfy the load demand, LP becomes exhausted after repeating a certain number of times as the optimization problem has no solution and load shedding is needed. The loadshedding function shed the load to its least possible value so that when OPF restarts, LP converges to a result. This process is repeated for next load hours until optimal power flow and load in forward transaction for each hour is found out.

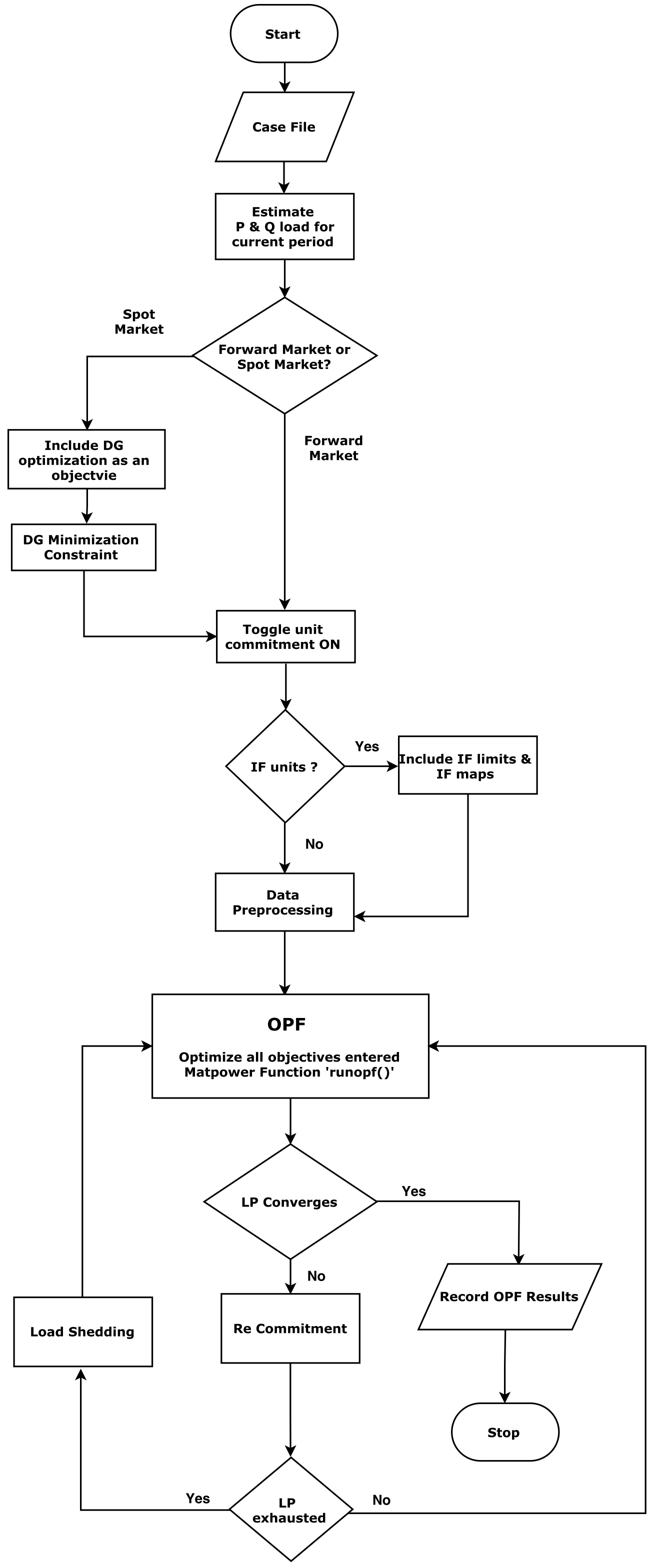

Figure 3.2: OPF Block

3.2 Spot Market power purchase Optimization

As the time for delivery approaches, if the utility did not make forward subscription tenders with the buyers, customers will be driven more by the spot market. Due to the penetration of distributed generation in the spot market, spot price could be different from that in forward transaction. Transactive Energy business model permit utilities to purchase power from these distributed generators and later sell them to customers at spot price. By purchasing power these distributed generators, utilities can meet their load demand which they fail to make tenders in forward position. Furthermore, utilities benefits from transport cost savings as most of these distributed generators are in location proximity to buyers. In this section, an algorithm for spot transaction optimization is proposed which calculates minimum power to be purchased from distributed generation to meet the load demand in spot market. Load in forward transaction and expected load in spot market was calculated in the previous section. The algorithm to optimize the spot market transactions and to calculate power purchased from distributed generators to maximize the utility profit and to minimize load shedding is proposed here.

3.2.1 Minimum power purchase calculations from DG

In previous section, load in forward transaction and spot market was calculated for every hour of the day. Here, the main objectives of the optimization is to purchase minimum power from the distributed generator so as to meet maximum spot market load, along with minimizing total cost of production and satisfying all system constraints. Once again an AC optimal power flow with standard Newton Raphson technique is used for optimization. The mathematics behind the proposed algorithm to optimize spot market transaction is presented below.

$$\text{Minimize:} \quad (i)\ J = \begin{cases} \sum_{i=1}^{n_G} \big[\big(C_i(P_{UG}(i)) + C_i(Q_{UG}(i))\big) \times I_{UG}(i) + S(i)\big] + \\ \sum_{i=1}^{N} \big[C_i\big(P_{DG}(i)\big) \times I_{DG}(i)\big] \end{cases} \tag{3.6}$$

$$(ii)\ G = \sum_{i=1}^{N} (P_{DG}(i)) \tag{3.7}$$

$$(iii)\ P_{LS} = \sum_{i=1}^{N} P_{LS}(i) \tag{3.8}$$

$$\text{subject to:} \quad \sum_{i=1}^{n_G} P_{UG}(i) \times I_{UG}(i) + \sum_{i=1}^{N} P_{DG}(i) \times I_{DG}(i) = P_L$$

$$P_{UG}^{min}(i) \leq P_{UG}(i) \leq P_{UG}^{max}(i)$$

$$V^{min}(i) \leq V(i) \leq V^{max}(i)$$

$$\forall F_k \leq F_k^{max}$$

$$\overset{n_{IL}}{\forall} \sum_{k=1}^{n_L} F_k \leq P_{IL}^{max}$$

where,

J = Objective function to minimize the total cost of generation

G = Objective function to minimize the total power purchased from distributed generators

P_{LS} = Total load shedding in MW

n_G = Total number of generators

N = Total number of buses

$C_i\left(P_{UG}(i)\right)$ = Average marginal cost (\$/MW) of utility generator i

$C_i\left(Q_{UG}(i)\right)$ = Average marginal cost for reactive power (\$/MVar) of utility generator i

$C_i\left(P_{DG}(i)\right)$ = Average marginal cost for power (\$/MVar) of distributed generator i

$I_{UG}(i)$ = Commitment state of Utility's Generator unit i

$I_{DG}(i)$ = Commitment state of Ditributed Generator unit i

$S(i)$ = Start-up cost of generator i

$P_{UG}(i)$ = MW Output of utility generator i

$Q_{UG}(i)$ = MVar Output of utility generator i

$P_{DG}(i)$ = MW Output of distributed generator i

$P_L(i)$ = Total Load demand at bus $i$including loss in transmission

$P_{UG}^{max}(i)$ = Maximum output capacity of generator$i$

$P_{UG}^{min}(i)$ = Minimum dispatch of generator i if turned on

$V(i)$ = Voltage at bus i

$V^{max}(i) =$ Maximum voltage limit at bus i

$V^{min}(i) =$ Minimum voltage limit at bus i

$F_k =$ Power flow through the transmission line k

$F_k^{max}(p,q) =$ Maximum power flow limit through the transmission line k

$IL =$ Interface limit

$n_{IL} =$ Number of interface limits

The objective of the optimization have three main objectives, namely minimization of total cost of generation including the cost of production from utility generators and distributed generators, minimization of power purchase from distributed generators to maximize utility profit, and minimization of load shedding in real time. Optimization has been performed to minimize load shedding by purchase of power from distributed generators. In order to maximize utility profit, the MW power purchased from DG (P_{DG}) should be minimum and just enough to prevent load shedding. An algorithm is proposed to find a solution for these three broad objectives by running one main optimization program for each hour of the day with spot market load calculated from forward transaction calculations. The output of these calculations are optimal power flow solution and a map showing optimal location and amount of power to be purchased from DG. Equation 3.9 shows that load in real time is the sum of load in Forward transaction and Spot transaction.

$$P_L^{SP}(t) = P_L(t) - P_L^{FM}(t) \tag{3.9}$$

where,

$P_L^{FM}(t) =$ Load in Forward Market at hour t

$P_L(t) =$ System load expected at hour t

$P_L^{SP}(t) =$ Load in Spot Market t

The total power purchased from DG is given by Equation 3.10. Here $I(i)$ gives the buses where power purchase is necessary and $P_{DG}(i)$ gives the quantity of power to be purchased so as to prevent load shedding.

$$\text{DG Power purchased by utility} = \sum_{i=1}^{N} P_{DG}(i) \times I_{DG}(i) \tag{3.10}$$

Flow chart given by Figure 3.2 depicts the algorithm used for optimization in spot market for each operational period. Unlike the optimization for forward transaction, the program follows path for spot market where purchase of power from DG is permitted. Once the program adds the DG parameters into the case file, it enables the constraint to minimize purchase from DG. Interface mapping and limits are turned on next to restrict the flow through interfaces to a predefined value. The case file along with new objective functions are then passed to optimization block where it uses Newton Raphson technique to solve the minimization function. If there exist a solution without DG, the LP converges without including DG and satisfying all constraints. If the LP do not converge, recommitment of generating units are performed and LP process repeats with different set of units committed until LP converges. If the LP becomes exhausted due to availability of utility generation resource not sufficient to satisfy load demand, it recommits with available set of distributed generation at each bus. The objective to minimize the power from DG is addressed in the OPF block. If the LP gets exhausted even after including DG, load shedding is needed. The loadshedding function shed the load to its least possible value so that when OPF restarts, LP converges to a result. This process is repeated for next load hours until optimal power flow and generator dispatch for each load is found out. Once forward and spot transactions are over the OPF results are then passed to the next section where price of power at each hour is determined.

3.3 Forward subscription price and Spot Price

The system operator has the ability to determine cost of power for every hour of the day, depending on the energy cost and system conditions. As described earlier, forward transactions are used to reduce risk of investment for sellers, whereas spot transactions are used to coordinate operating decisions. Again, all parties, big and small, have access to the same spot transaction exchanges. In spot market the cost of power could be different from forward transaction due to the penetration of distributed energy resources into the main grid. System operator determines the energy cost in spot market depending on prevailing system state. In this work, locational marginal pricing which is currently popular among several ISOs, is used to calculate price in forward and spot market. While calculating the nodal price in forward transaction, DG is not considered since it gives the actual price customers will be paying to the utility in normal situation. Whereas in spot market the distributed generators are also considered while calculating the nodal price since in real time ISO determine the price of every bus depending on the availability of generators in the region of operation. Hence the proposed pricing mechanism uses OPF result, which gives the dispatch status of various generators and LMP to calculate node price in forward and spot market for every hour.

3.3.1 LMP calculation

The methodology used to calculate LMP at different buses follows work [32] described in Chapter 2, subsection 2.2.4 and the focus of this section is the implementation of algorithm to forward and spot transactions. Transmission lines in power network normally operate under thermal, voltage, and stability constraints. However, as demand of power increases there could be a situation where transmission lines are forced to operate closer to their thermal limits. This leads to transmission line congestion and costs more for the incremental supply of power since this prevents the use of next least cost generator from dispatching thereby forcing higher cost generators to dispatch to meet the load demand. Without network congestion and power loss in transmission lines, the cost of power at every bus would remain the same. Hence, transmission line congestion is the key factor in determining LMP at every bus. Energy cost, congestion cost and loss price are the components to be calculated to determine LMP of a given bus. Energy cost is the price, market seller has to offer on a reference bus (usually slack bus of the system). Loss price price is calculated based on transmission line losses. Energy and congestion components are calculated based on work done in [32], where the LMP is calculated based on a DC power flow and loss price is not addressed. In this work, energy and congestion price of LMP has been calculated based on [32] and loss price based on [5] where loss price is calculated as the product of energy price at the reference bus and loss factor. Detailed calculations of LMP considering all three components has been presented in chapter 2.

Figure 3.3 depicts the steps in LMP process for each operational period.The opf result from previous section is first analyzed to get all binding constraints. Binding constraints could be due to congestion in transmission lines or interface. The OPF result is passed through b.c blocks to

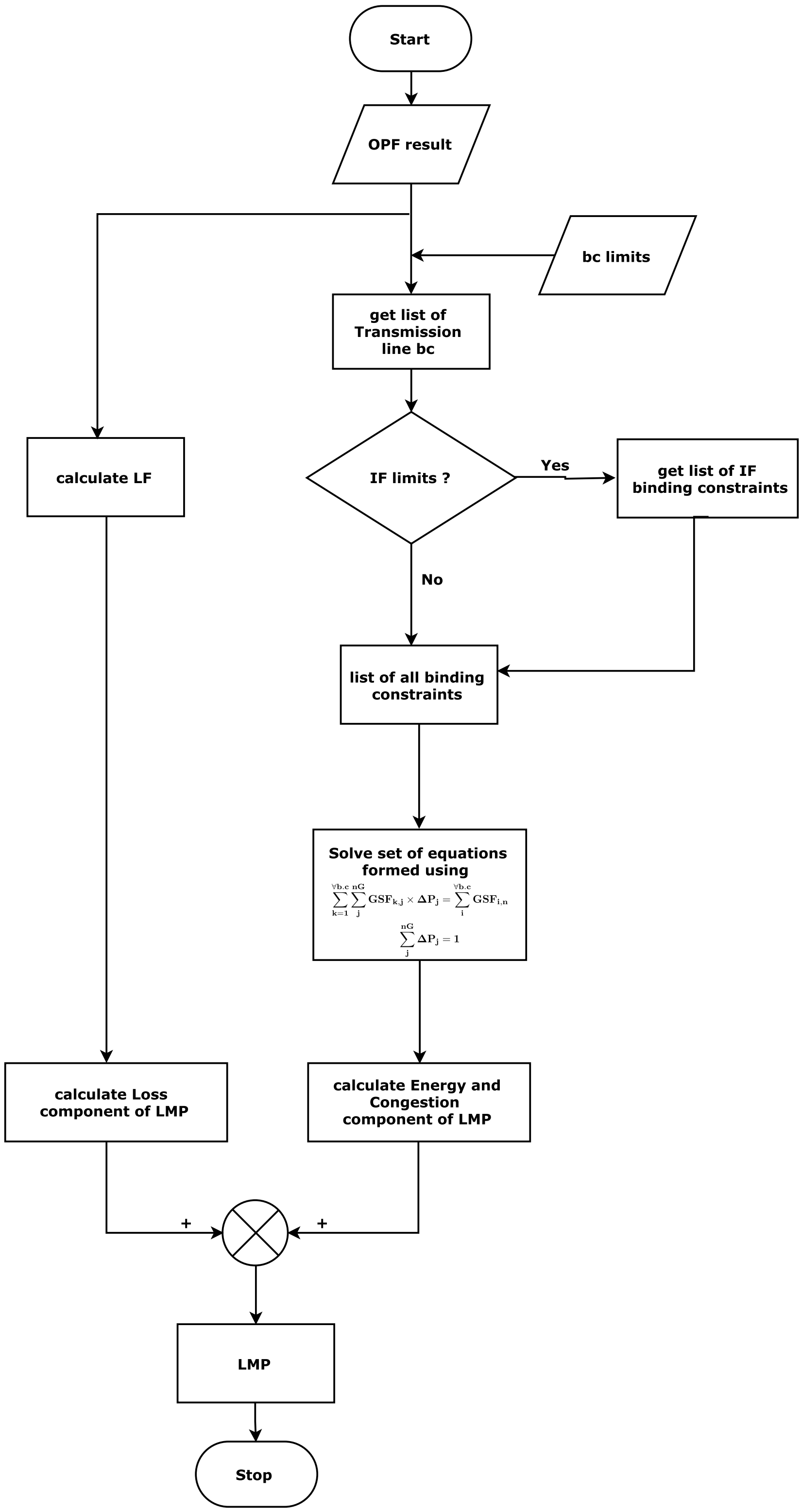

Figure 3.3: LMP Block

quantify the number of binding constraints in various transmission lines. Incremental flow equations are formed using the system binding constraints for various lines (Equation 2.49). Incremental flow equations are sets of linear equations and are solved in this work using a special Matlab function called `mldivide`. This function uses different set of algorithms internally to solve a set of linear equations based on number of equations and unknowns. Here number of equations and unknown could be different. The output of this block gives the set of generators and its contribution for next incremental MW. This is then passed through the incremental price equation block to calculate energy and congestion components of LMP. Next, Loss price is calculated based on OPF result of Step 1 in Figure 3.1. It is calculated based on Equation 2.47 where system parameters are obtained from shared by the two paths. Finally, energy, congestion, and loss components of LMP are added together to get the LMP of every bus.

3.3.2 Calculation of Forward transaction price

The mathematical equation corresponds to LMP for forward transactions follows from Equation 2.49. LMP is calculated based on the incremental flow equation. This is a set of linear equations and are solved to get the contribution of each generator for the next MW increase of power. In forward transaction only utility generators are considered in incremental flow equation since FS process is determined based on capability of utility to meet its load in forward transaction. Incremental flow equation for a bus i is defined below.

$$\forall k \in B_c : \sum_{j}^{n_G} GSF_{k,j} \times \Delta P_G(j) = GSF_{k,i} \tag{3.11}$$

$$\sum_{j=1}^{n_G} \Delta P_{UG}(j) = 1 \tag{3.12}$$

where,

$\Delta P_{UG}(j)$ = Contribution by utility generator at bus j

k = Trasmission line (or interface) that has a binding constraint

j = Bus where a generator is located

B_c = A set of binding constraints

However, when a binding constraint k is an interface of two or more transmission lines, $GSF_{k,j}$

in the above equation is the composite generator shift factor, which is the sum of generator shift factors of bus j on all the transmission lines that are part of the interface. Similarly, the composite generator shift factor $GSF_{k,i}$ of bus i on all the transmission lines that are part of the interface is needed on the right hand side of the equation when k is an interface of two or more lines.

$\Delta P_{UG}(j)$ is then used in incremental price equation to calculate LMP at every bus. Incremental price equation is given by Equation 3.13

$$LMP_{E,C}(i) = \sum_{j}^{n_G} \Big(\Delta P_{UG}(j) \times UMC(j)\Big) \tag{3.13}$$

where,

$LMP_{E,C}(i)$ = Energy and Congestion components of LMP at bus i

$UMC(j)$ = Unit marginal cost of generator at bus j

Next LMP_{loss} is calculated based on Equation 2.47 described in Chapter 2. Sum of LMP_{loss} and $LMP_{E,C}$ gives the total LMP of a bus.

$$LMP(i) = LMP_{loss}(i) + LMP_{E,C}(i) \tag{3.14}$$

3.3.3 Calculation of Spot price

While calculating the spot price both distributed generators and utility generators have to considered since the calculations are done in real time, considering all available set of generators. Incremental equations are formed using binding constraints from OPF result of spot market and are solved to get LMP at various buses. Here contribution of each generator, either utility or distributed generator is included in the incremental flow equation. Modifications to Equation 2.49 to include both utility generators and distributed generators are shown below.

$$\forall k \in B_c : \sum_{j}^{N} GSF_{k,j} \times \Big[\Delta P_{UG}(j);\Delta P_{DG}(j)\Big] = GSF_{k,i} \tag{3.15}$$

$$\sum_{j}^{n_G} \Delta P_{UG}(j) + \sum_{j=1}^{N} \Delta P_{DG}(j) = 1 \tag{3.16}$$

where,

$\Delta P_{UG}(j)$ = Contribution by utility generator at bus j

$\Delta P_{DG}(j)$ = Contribution by distributed generator at bus j

k = Trasmission line (or interface) that has a binding constraint

j = Bus where a generator is located

B_c = A set of binding constraints

$\Delta P_{UG}(j)$ is then used in incremental price equation to calculate LMP at every bus. Incremental price equation is given by Equation 3.13

$$LMP_{E,C}(n) = \sum_{j}^{n_G} \left(\left[\Delta P_{UG}(j); \Delta P_{DG}(j) \right] \times UMC(j) \right) \tag{3.17}$$

Here $LMP_{E,C}(n)$ is the Energy and Congestion components of LMP at bus n and $UMC(j)$ is the Unit marginal cost of generator at bus j LMP_{loss} is calculated next, based on Equation 2.47 described in Chapter 2. Sum of LMP_{loss} and $LMP_{E,C}$ gives the total LMP of a bus.

$$LMP(i) = LMP_{loss}(i) + LMP_{E,C}(i) \tag{3.18}$$

3.4 Analysis of consumer payments in forward and spot market

In this section, economic analysis of various forward and spot market transactions is performed, by implementing the proposed strategy to purchase power from distributed generations and selling it in spot market. Here the methodology to calculate cost of production and payments in two different markets is presented. In forward transaction, cost of production is given by the load in forward subscription and the total consumer payments corresponds to the forward subscription tenders utility make. On the contrary, in spot market the total cost of production is given by the production cost of utility generators and power purchased from distributed generators. Consumer payment in spot market is for the load not included in forward subscription and the total consumer payment is given by the sum of consumer payments in forward and spot transactions. Figure 3.4 depicts the entire transactive accounting procedure used in this work. For forward market calculations, the OPF result of FM from step 1 and Forward subscription price from step 2 is used. Similarly, for spot market calculations, the OPF result of SM from step 1 and Spot price from step 2 is used. Net profit which the difference of total consumer payment and cost of production, is calculated at the end of each market accounting.

3.4.1 Calculation of various Transactions in Forward Subscription

From the results of optimization, the generation schedule is obtained, which is used to calculate cost of production in forward transactions. If $P_G(1), P_G(2), ...P_G(n_G)$ are the utility generator dispatch at a given time t, minimum production at a given time t can be calculated using the following expression.

$$C_{FS,PUG}(t) = \sum_{i=1}^{n_G} \big(a(i)P_G^2(i) + b(i)P_G(i) + c(i) \big) \tag{3.19}$$

where $C_{FS,PUG}(t)$ is the minimum cost of production in FS and a, b, c are quadratic cost components of various utility generators. Total cost of production per day can be calculated by adding individual cost of production for every hour.(Equation 3.20)

$$\begin{aligned} C_{FS,PUG}^{tot} &= \sum_{t=1}^{T} C_{FS,PUG}(t) \\ &= \sum_{t=1}^{T} \sum_{i=1}^{n_G} \big(a(i)P_G^2(i,t) + b(i)P_G(i,t) + c(i) \big) \end{aligned} \tag{3.20}$$

Forward Transaction consumer Payment at bus i is calculated using Equation 3.1 where LMP is the Forward Market LMP and load is the net load of given bus. Forward subscription load is calculated in optimization process described in section 3.1. Here T represents the total hours of operation.

$$CP_{FS}(i) = LMP_{FS}(i) \times \Big(P_L(i) - P_{LS}(i) \Big) \tag{3.21}$$

Here CP_{FS}, P_L, P_{LS} and LMP_{FS} represents the consumer payments, system load, expected load shedding, and LMP at various buses respectively. Consumer Payment at a given hour t is calculated by summing the total amount collected from all buses at that load hour . Here T represents the

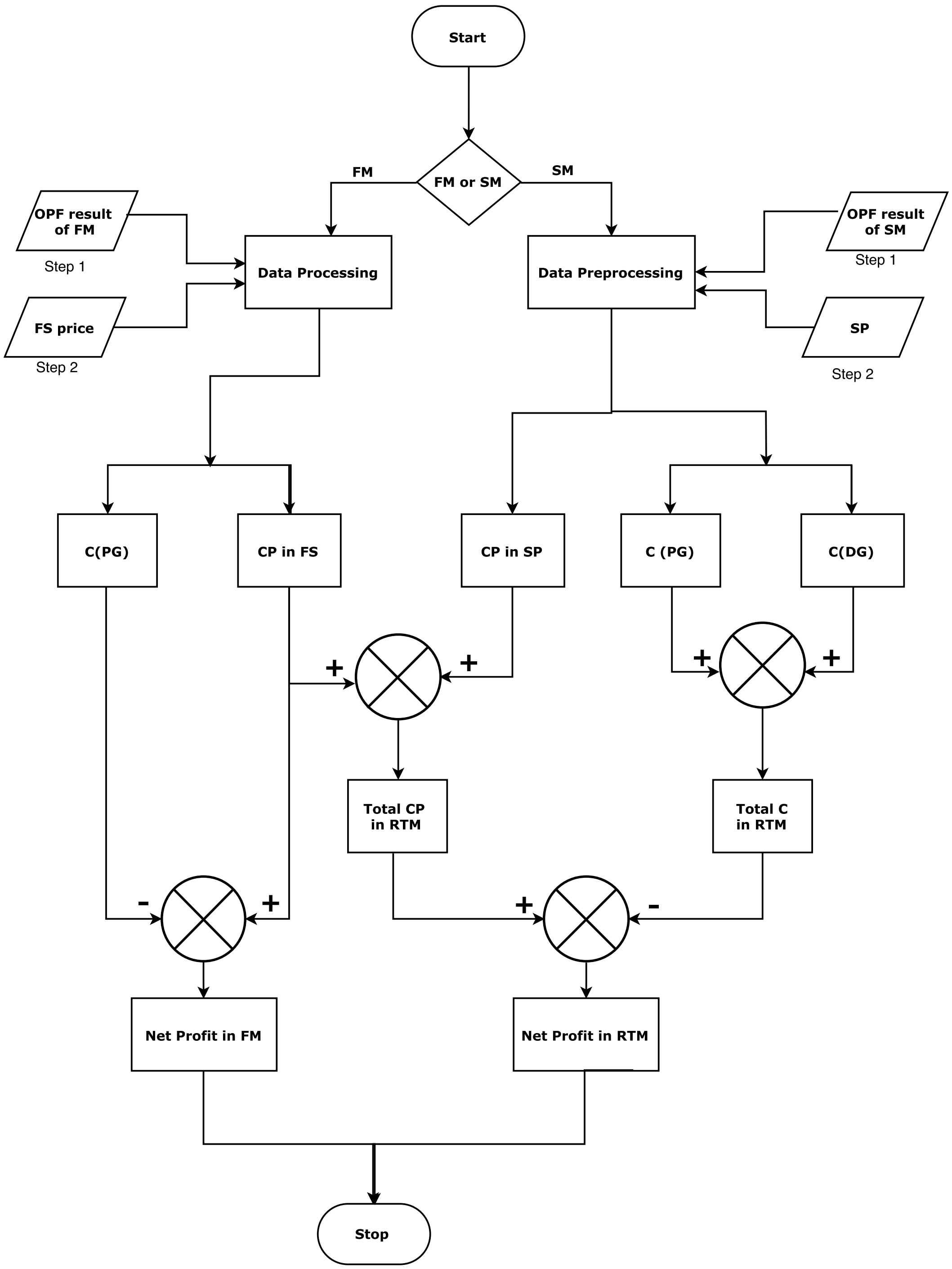

Figure 3.4: Transactive Accounting Block

total hours of operation.

$$\begin{aligned} CP_{FS}(t) &= \sum_{i=1}^{N} CP_{FS}(i) \\ &= \sum_{t=1}^{T}\sum_{i=1}^{N} LMP_{FS}(i,t) \times \Big(P_L(i,t) - P_{LS}(i,t)\Big) \end{aligned} \tag{3.22}$$

Consumer payment per day is calculated by adding individual consumer payments from all load bus and then taking the cumulative sum of those over a T hour time interval.

$$\begin{aligned} CP_{FS}^{tot} &= \sum_{t=1}^{T} CP_{FS}(t) \\ &= \sum_{t=1}^{T}\sum_{i=1}^{N} LMP_{FS}(i,t) \times \Big(P_L(i,t) - P_{LS}(i,t)\Big) \end{aligned} \tag{3.23}$$

Net Profit (NP_{FS}^{tot}) in trading power in a given hour t is calculated based on Equation 3.19 and Equation 3.22. The difference between net consumer payments in Forward Market tenders and minimum production cost gives the profit for that load hour.

$$NP_{FS}^{tot}(t) = CP_{FS}^{tot}(t) - C_{FS,PUG}^{tot}(t) \tag{3.24}$$

Here profit of a particular transaction is indicated by positive sign for NP, and vice versa negative sign indicates a loss for the utility. Calculations for net profit per is shown in Equation 3.25.

$$\begin{aligned} NP_{FS}^{tot} &= \sum_{t=1}^{T} CP_{FS}(t) - C_{FS,PUG}(t) \\ &= CP_{FS}^{tot} - C_{FS,PUG}^{tot} \end{aligned} \tag{3.25}$$

3.4.2 Calculation of various Transactions in Real Time Market

If $P_{UG}(1), P_{UG}(2), ...P_{UG}(n_G)$ are the utility generator dispatch and $P_{DG}(1), P_{DG}(2), ...P_{DG}(n_{DG})$ are the distributed generator dispatch at a given time t, minimum production cost for UG and DG can be calculated using the expressions given below (Equation 3.26, 3.27, 3.28). Here, P_{UG} , P_{DG}, P_L^{FM},P_L^{SP}, and $C_{PDG,SP}$ represents utility generation, distributed generation, load in forward subscription, load in spot market, and cost of production in spot market respectively. In Real Time Market, P_{UG} could be different from P_L^{FM} and similarly P_{DG} could be different from P_L^{SP}. Utility generator dispatch and distributed generator dispatch are decided based on multilevel optimization technique proposed in the previous sections. By selling power purchased from distributed generators, could contribute to net profit for the utility in real time market.

$$C_{PUG,SP}(t) = \sum_{i=1}^{n_G} \Big(a(i)P_{UG}^2(i,t) + b(i)P_{UG}(i,t) + c(i) \Big) \tag{3.26}$$

$$C_{PDG,SP}(t) = \sum_{i=1}^{n_{DG}} \Big(a(i)P_{DG}^2(i,t) + b(i)P_{DG}(i,t) + c(i) \Big) \tag{3.27}$$

$$C_{SP}(t) = C_{PUG,SP}(t) + C_{PDG,SP}(t) \tag{3.28}$$

Total cost of production over a T hour time interval can be calculated by adding individual cost of each hour

$$C_{PUG,SP}(t) = \sum_{t=1}^{T} \sum_{i=2}^{n_G} \Big(a(i)P_{UG}^2(i,t) + b(i)P_{UG}(i,t) + c(i) \Big) \tag{3.29}$$

$$C_{PDG,SP}(t) = \sum_{t=1}^{T} \sum_{i=1}^{n_{DG}} \Big(a(i)P_{DG}^2(i,t) + b(i)P_{DG}(i,t) + c(i) \Big) \tag{3.30}$$

$$C_{SP}(t) = \sum_{t=1}^{T} (C_{PUG,SP}(t) + C_{PDG,SP}(t)) \tag{3.31}$$

Consumer payment in Real Time Market includes payments in Forward Subscription and payments in Spot Market. Calculations for consumer payment in Forward subscription was described in Equation 3.23. Load and consumer payment in spot market and forward market remains the same, even if the centralized generator dispatch deviates from Forward Market calculation. Hence consumer payments in forward market and spot market remains the same. Consumer Payments in Spot Market at bus i is calculated using Equation 3.32 where Spot Market LMP and Spot Market load is considered.

$$CP_{SP}(i) = LMP_{SP}(i) \times P_L^{SP}(i) \tag{3.32}$$

Consumer Payment at a given hour t is calculated by adding consumer payments from all load buses. (Equation 3.33)

$$\begin{aligned} CP_{SP}(t) &= \sum_{i=1}^{N} CP_{SP}(i) \\ &= \sum_{i=1}^{N} LMP_{SP}(i) \times P_L^{SP}(i) \end{aligned} \tag{3.33}$$

Consumer Payment per day can be calculated as the sum of individual consumer payments at each load bus and then taking the cumulative sum of those over a T hour time interval. Equation 3.34

$$\begin{aligned} CP_{SP}^{tot} &= \sum_{t=1}^{T} CP_{SP}(t) \\ &= \sum_{t=1}^{T} \sum_{i=1}^{N} LMP_{SP}(i,t) \times P_L^{SP}(i,t) \end{aligned} \tag{3.34}$$

Net Profit in trading power on a given hour t is calculated based on Equation 3.28 , 3.22, 3.33. The difference between minimum production cost and net consumer payments in Forward Subscription and Spot Price gives the net profit at that hour.

$$\begin{aligned} NP(t) &= (CP_{FS}(t) + CP_{SP}(t)) - C_{SP}(t) \\ &= (CP_{FS}(t) + CP_{SP}(t)) - (C_{PUG,SP}(t) + C_{PDG,SP}(t)) \end{aligned} \tag{3.35}$$

Once again, profit of a particular transaction is indicated by positive sign for NP, and vice versa, negative sign indicates a loss for the utility at given time. Net Profit per day is calculated using following Equation 3.36

$$\begin{aligned} NP^{tot} &= \sum_{t=1}^{T} (CP_{FS}(t) + CP_{SP}(t)) - C_{SP,PUG}(t) \\ &= CP_{FS}^{tot} + CP_{SP}^{tot} - C_{SP}^{tot} \end{aligned} \tag{3.36}$$

3.5 Analysis of DG benefits

In this section various metrics used to analyze the benefits of purchasing power from distributed generation following the proposed algorithm is presented.

3.5.1 Percentage Profit improvement (PPI)

Calculations for net profit per day in forward market is shown in Equation 3.25 and spot market shown in Equation 3.36. Here the percentage increase or decrease in profit (PPI) when utility invests in distributed generator is analyzed.

$$\text{PPI} = \frac{NP_{SP}^{tot} - NP_{FS}^{tot}}{NP_{FS}^{tot}} \times 100\% \tag{3.37}$$

3.5.2 Percentage load shedding reduction

Major benefit expected with purchase of power from distributed generation is the improvements in load shedding. Without distributed generation utility may not be able to make tenders with all customers in forward market. With purchase of power in there is expected to be significant improvements in load shedding. The improvement in profit by purchase of power has been analyzed in the previous section. Here the focus is to show the percentage improvements in load shedding by including DG. Load shedding in From Equation 3.9, we know that load shedding expected in forward market is the difference of total system load and load in forward market.

$$P_{LS} = P_L - P_L^{FM} \tag{3.38}$$

After including DG, the load shedding is expected to decrease in real time. The difference between the system load demand and total load expected to serve in forward and spot market gives the expected load shedding in real time market.

$$P_{LS}^{FM} = P_L - (P_L^{FM} + P_L^{SP}) \tag{3.39}$$

The mathematical expression for percentage improvements in load shedding (LSI) is given below.

$$\text{LSI} = \frac{P_{LS} - P_{LS}^{FM}}{P_{LS}} \times 100\% \tag{3.40}$$

Combining equations 3.38 and 3.39, the expression for load shedding improvements in Equation 3.40 can be simplified as shown below.

$$\text{LSI} = \frac{\left(P_L - P_L^{FM}\right) - \left(P_L - (P_L^{FM} + P_L^{SP})\right)}{\left(P_L - P_L^{FM}\right)}\% \tag{3.41}$$

$$= \frac{P_L^{SP}}{P_{LS}} \times 100\% \tag{3.42}$$

3.5.3 Transmission Line Loading (TLL)

Distributed generation benefits from their location in proximity to customers locations. This could reduce transmission line congestion and enabling more utility production. Here, percentage improvement in transmission line power flow is analyzed. The ratio of percentage flow in transmission line to total load demand in forward and spot market is analyzed.

i Forward Subscription

In forward transaction,the total load demand met by utility is $P_L^{FM}(t)$. The mathematical expression for percentage improvements in transmission line loading in forward market given below.

$$TLL_{FS} = \frac{\sum\limits_{t=1}^{T}\sum\limits_{k=1}^{K}\frac{F_k(t)}{F_k^{max}(t)}}{\sum\limits_{t=1}^{T}\left(\frac{P_L^{FM}(t)}{P_L(t)}\right)} \times 100\% \tag{3.43}$$

ii Spot Transaction

In real time, the load demand met by utility is the sum of forward market load $P_L^{FM}(t)$ and spot market load $P_L^{SP}(t)$. The The mathematical expression for percentage improvements in transmission line loading in spot market given below.

$$TLL_{SP} = \frac{\sum\limits_{t=1}^{T}\sum\limits_{k=1}^{K}\frac{F_k(t)}{F_k^{max}(t)}}{\sum\limits_{t=1}^{T}\left(\frac{P_L^{FM}(t) + P_L^{SP}(t)}{P_L(t)}\right)} \times 100\% \tag{3.44}$$

F_k = Power flow through the transmission line k

F_k^{max} = Maximum power flow limit through the transmission line k

$P_L^{FM}(i)$ = Total Load in forward subscription at bus i

P_L = Total Load in bus i

K = Total number of transmission lines

T = Total number of hours

Chapter 4

Test System

The purpose of this chapter is to introduce the test systems and software used in this work. There are two test study systems used in this thesis; a six bus system and an IEEE fourteen bus system. The program used to implement the logic is coded in MATPOWER. The tests systems are described in detail below.

4.1 Six Bus System

The six bus system shown in Figure 4.1 is from papers [32,33]. The system consists of 6 buses, out of which 3 are load buses (buses 4, 5 and 6). There are 3 generators in the system (buses 1, 2 and 3). Bus 1 which has generator 1 is defined to be slack bus. There are a total of eleven branches connecting the buses. The generation capacity of the system is 530 MW.

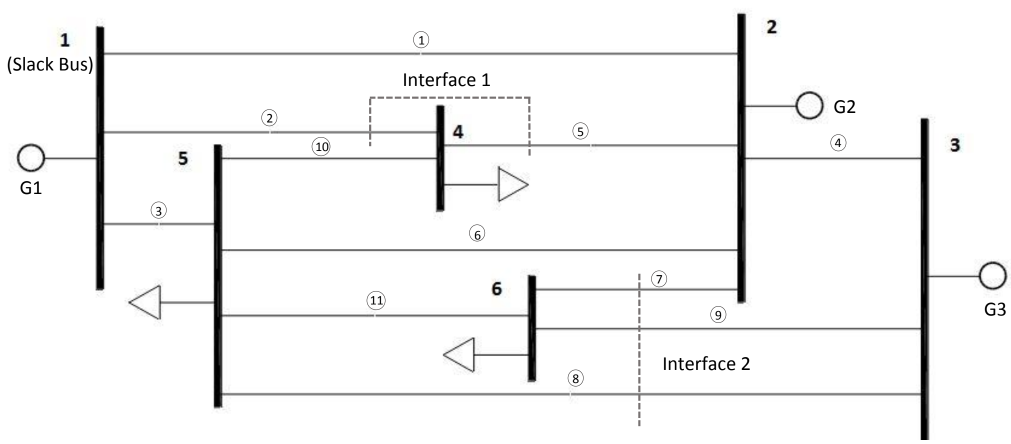

Figure 4.1: 6 Bus System

4.1.1 Bus data

The test system consists of six buses. Buses 1,2,3 are connected to the utility generator and remaining buses are connected to the distributed generators. Buses 4, 5, and 6 consists of P loads. The detail information of all the buses with their respective bus ID are listed in Table 4.1

Bus ID	Type	Pd (MW)	Qd (Mvar)	Vm (p.u)	Angle	Vmax (p.u)	Vmin (p.u)	baseKV
1	Slack	0	0	1	0	1.05	0.95	138
2	PV	0	0	1	0	1.05	0.95	138
3	PV	0	0	1	0	1.05	0.95	138
4	PV	70	0	1	0	1.05	0.95	138
5	PV	70	0	1	0	1.05	0.95	138
6	PV	70	0	1	0	1.05	0.95	138

Table 4.1: Six Bus system bus data

4.1.2 Branch data

The test system consists of 11 transmission lines. Line Resistance, Reactance and charging Suseptance of these lines are shown in Table 4.2. Table also gives the thermal rating of the transmission lines.

Branch ID	From Bus	To Bus	Line R (p.u)	Line X (p.u)	Charging B (p.u)	Rating (MW)	Status
1	1	2	0.1	0.2	0.04	30	1
2	1	4	0.05	0.2	0.04	50	1
3	1	5	0.08	0.3	0.06	40	1
4	2	3	0.05	0.25	0.06	20	1
5	2	4	0.05	0.1	0.02	40	1
6	2	5	0.1	0.3	0.04	20	1
7	2	6	0.07	0.2	0.05	30	1
8	3	5	0.12	0.26	0.05	20	1
9	3	6	0.02	0.1	0.02	60	1
10	4	5	0.2	0.4	0.08	20	1
11	5	6	0.1	0.3	0.06	20	1

Table 4.2: Six Bus system branch rating

4.1.3 Generator data

Table 4.3 outlines the utility generator data of test system. The three utility generators are in buses 1, 2, and 3. Maximum and minimum capacity of each generator is also given below. Table 4.4 and Table 4.5 shows the quadratic cost function of utility and distributed generator respectively. Quadratic cost function is represented using the Equation 4.1 described in previous chapter. Here b represents the incremental cost and c represents the fixed cost of generation. All non utility buses are assumed to have same distributed generator.

$$C = a.P_G^2 + b.P_G + c \tag{4.1}$$

Gen.ID	Bus	Type	Pg	Qg	Pmax	Pmin	Qmax	Qmin	Vg
1	1	Slack	0	0	200	50	0	0	1
2	2	PV	50	0	150	37.5	0	0	1
3	3	PV	60	0	180	45	0	0	1

Table 4.3: Six Bus system utility generator data

Generator ID	Bus	a ($/hr)	b ($/hr)	c ($/hr)
1	1	0	41.47	0
2	2	0	25.77	0
3	3	0	39.3	0

Table 4.4: Six Bus system utility generator quadratic cost function

Vg	Pmax	Pmin	Qmax	Qmin	a($/hr)	b($/hr)	c($/hr)
1	50	1	50	0	0.003	43	0

Table 4.5: Six Bus system distributed generator quadratic cost function

4.1.4 Interface data

There are two interfaces in six bus test system as shown in Table 4.6 . The first interface is rated at 88MW and consists of branches 2 and 5. The second interface is rated at 100MW and consists of branches 7, 8 and 9.

Interface ID	Limits (MW)	Line ID
1	88	2 5
2	100	7 8 9

Table 4.6: Six Bus system Interface data

4.2 Fourteen Bus System

The IEEE 14 Bus Test Case represents a portion of the American Electric Power System (in the Midwestern US) as of February, 1962 [16] . The IEEE 14 bus system shown in Figure 4.2 is from [16]. The system consists of 2 utility generators, 17 transmission lines, 11 loads and 3 synchronous generators. The two generators in the system are at buses 1 and 2, with bus 1 being the slack bus of the system. The generating capacity of the system is 472.4 MW and 60 MVar.

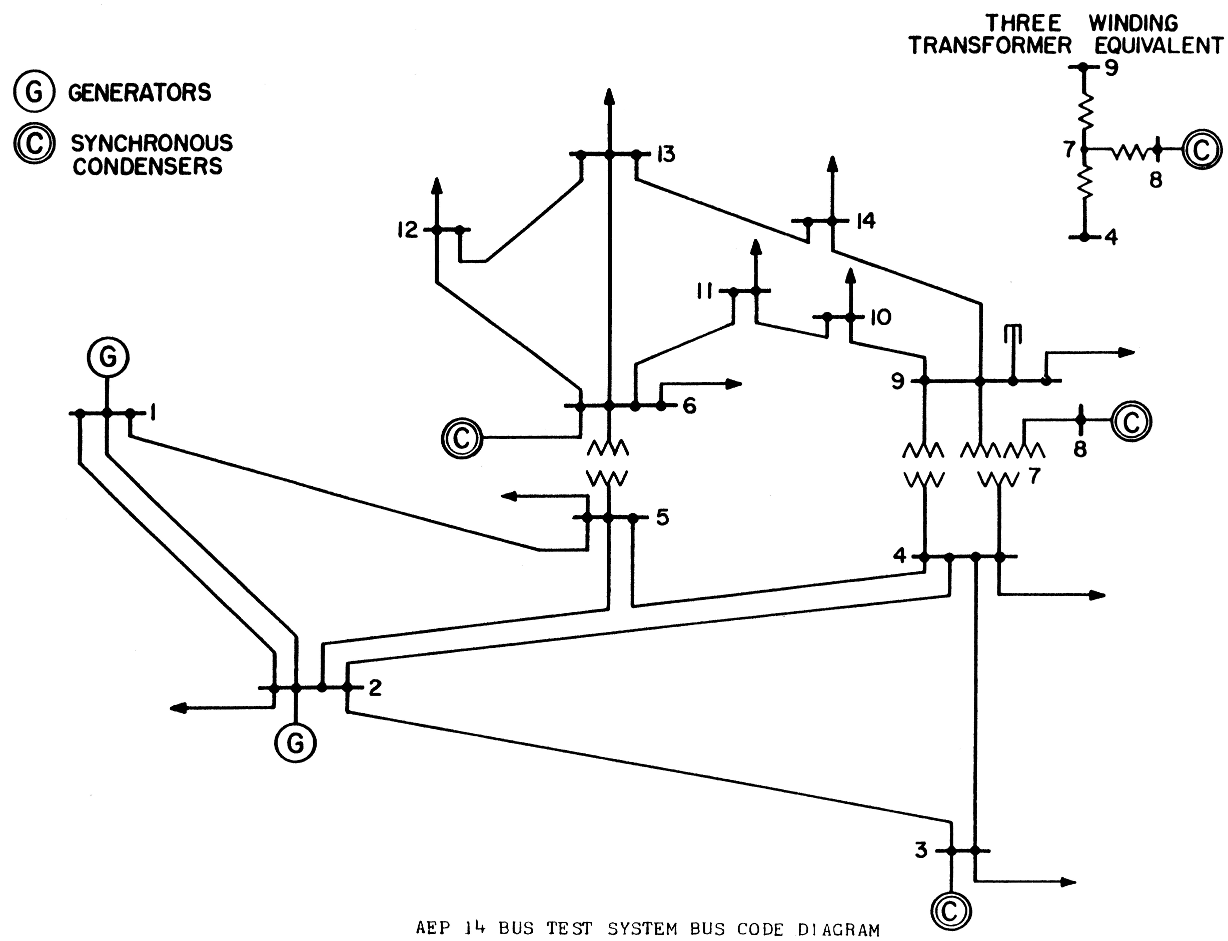

Figure 4.2: 14Bus System, Source: [16]

In fourteen bus sytem, unlike six bus system, there are no interface limits. However, there are synchronous condensers. The synchronous condensers were treated here as fixed shunt for ease of calculation. The modified 14 bus system with synchronous generators treated as fixed shunt is shown below in Figure 4.3 .

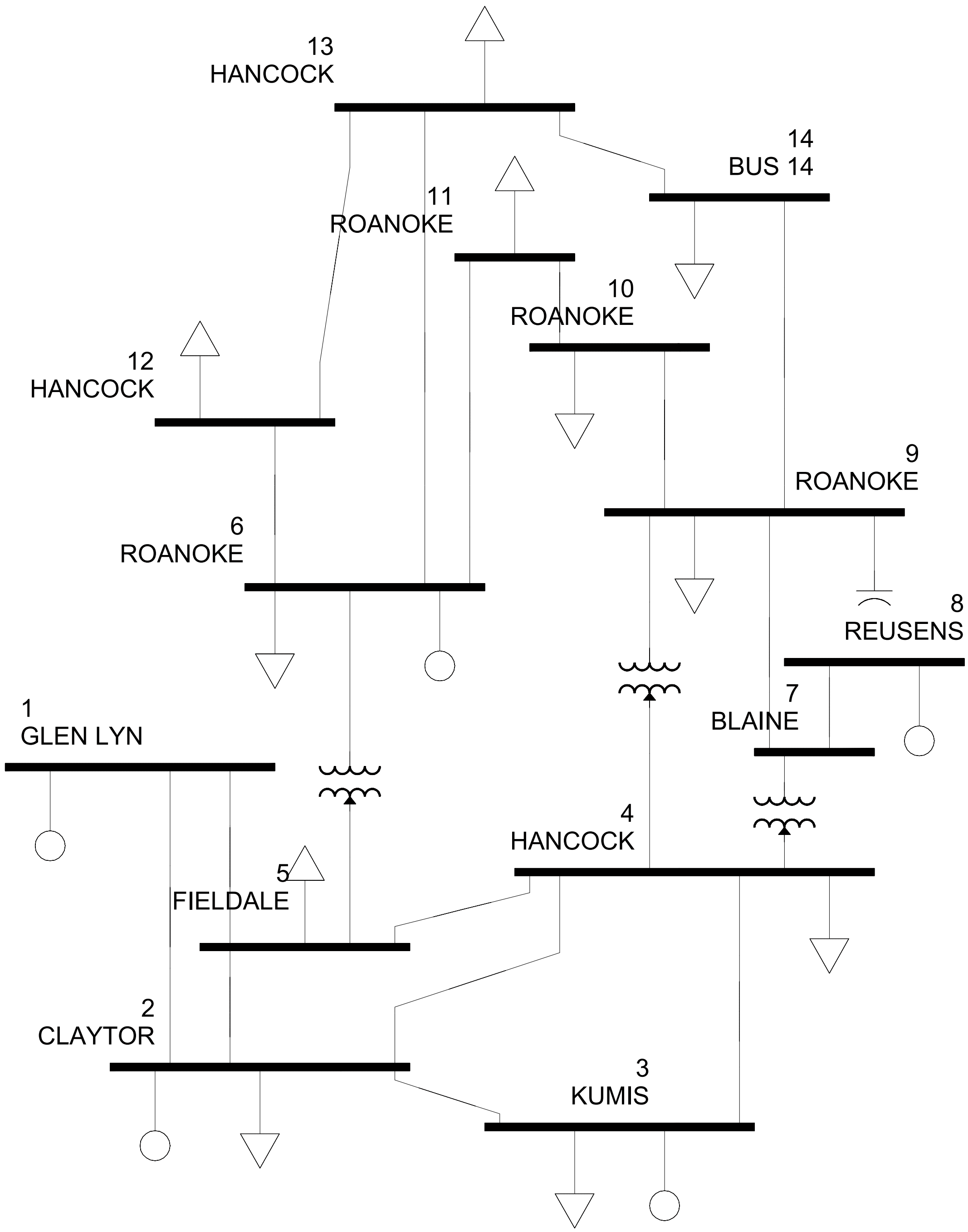

Figure 4.3: Modified 14 bus system

4.2.1 Bus data

The test system consists of fourteen buses. Buses 1 and 2 are connected to the utility generator and remaining buses are connected to the distributed generators. Buses 2, 3, 4, 5, 6, 9, 10, 11, 12, 13, and 14 consists of PQ loads. The detail information of all the buses with their respective bus ID are listed in Table 4.7

Bus ID	Type	Pd (MW)	Qd (Mvar)	Vm (p.u)	angle	Vmax (p.u)	Vmin (p.u)	baseKV
1	Slack	0	0	1.06	0	1.06	0.94	138
2	PV	21.7	12.7	1.045	-4.98	1.06	0.94	138
3	PV	94.2	19	1.01	-12.72	1.06	0.94	138
4	PV	47.8	-3.9	1.019	-10.33	1.06	0.94	138
5	PV	7.6	1.6	1.02	-8.78	1.06	0.94	138
6	PV	11.2	7.5	1.07	-14.22	1.06	0.94	138
7	PV	0	0	1.062	-13.37	1.06	0.94	138
8	PV	0	0	1.09	-13.36	1.06	0.94	138
9	PV	29.5	16.6	1.056	-14.94	1.06	0.94	138
10	PV	2	9	1.051	-15.1	1.06	0.94	138
11	PV	2	3.5	1.057	-14.79	1.06	0.94	138
12	PV	2	6.1	1.055	-15.07	1.06	0.94	138
13	PV	2	13.5	1.05	-15.16	1.06	0.94	138
14	PV	2	14.9	1.036	-16.04	1.06	0.94	138

Table 4.7: Fourteen Bus system bus data

4.2.2 Branch data

The test system consists of 20 transmission lines. Line Resistance, Reactance, charging Suseptance, and thermal limits of these lines are shown in Table 4.8. The test system consists of three winding transformers. Table 4.9 shows the reactance and transformation ratio of these transformers.

Branch ID	FromBus	ToBus	Line R (p.u)	Line X (p.u)	Charging B (p.u)	Rating (MW)	status
1	1	2	0.01938	0.05917	0.0528	140	1
2	1	5	0.05403	0.22304	0.0492	65	1
3	2	3	0.04699	0.19797	0.0438	65	1
4	2	4	0.05811	0.17632	0.034	51	1
5	2	5	0.05695	0.17388	0.0346	39	1
6	3	4	0.06701	0.17103	0.0128	23	1
7	4	5	0.01335	0.04211	0	54	1
11	6	11	0.09498	0.1989	0	7	1
12	6	12	0.12291	0.25581	0	8	1
13	6	13	0.06615	0.13027	0	17	1
14	7	8	0	0.17615	0	10	1
15	7	9	0	0.11001	0	26	1
16	9	10	0.03181	0.0845	0	6	1
17	9	14	0.12711	0.27038	0	10	1
18	10	11	0.08205	0.19207	0	4	1
19	12	13	0.22092	0.19988	0	2	1
20	13	14	0.17093	0.34802	0	6	1

Table 4.8: Fourteen Bus system branch rating

Branch ID	FromBus	ToBus	Line R (p.u)	Line X (p.u)	Charging B (p.u)	Ratio (p.u)
8	4	7	0	0.20912	0	0.978
9	4	9	0	0.55618	0	0.969
10	5	6	0	0.25202	0	0.932

Table 4.9: Fourteen Bus system transformer data

4.2.3 Generator data

Table 4.10 outlines the utility generator data of test system. The utility generators are in buses 1, and 2. Maximum and minimum capacity of each generator is also given below. Table 4.11 and Table 4.12 shows the quadratic cost function of utility and distributed generator respectively. Quadratic cost function is represented using the Equation 4.1 where b represents the incremental cost and c represents the fixed cost of generation. All non utility buses are assumed to have same distributed generator.

Gen. ID	Bus	Type	Pg	Qg	Pmax	Pmin	Qmax	Qmin	Vg
1	1	Slack	232.4	-16.9	332.4	0	10	0	1
2	2	PV	40	42.4	140	0	50	-40	1

Table 4.10: Fourteen Bus system utility generator data

Generator ID	Bus	a($/hr)	b($/hr)	c($/hr)
1	1	0.043	20	0
2	2	0.25	20	0

Table 4.11: Fourteen Bus system utility generator quadratic cost function

Vg	Pmax	Pmin	Qmax	Qmin	a($/hr)	b($/hr)	c($/hr)
1	50	1	50	0	0.003	43	0

Table 4.12: Fourteen Bus system distributed generator quadratic cost function

4.3 Simulation Tool - MATPOWER 5.1

MATPOWER is an open-source Matlab power system simulation package used to solve various power system studies [59, 60]. It is a package of Matlab files for solving power flow and optimal power flow problems in power system. Matpower provides full access to its users to access the code and allow options to modify. It is intended as a simulation tool for researchers and educators to use and modify. This feature of Matpower has been used widely in this work to run simulations on required set of conditions.

It has large number of built-in functions to perform various power system operations such as dc power flow, ac power flow, ac optimal power flow, dc optimal power flow, security constrained optimal power flow, OPF-based auction markets and so forth. It also includes tools for calculating power transfer and line outage distribution factors (GDF's and LODF's) as well most of system variables.

Matpower v5.1, downloaded from (http://www.pserc.cornell.edu/matpower/), was used for the majority of simulations in this work. The program was modified to provide the ability to change the problem formulation necessary for this work. This modification further enabled addition of other functions not addressed by built-in functions, which has been widely used throughout this work. Furthermore, MATPOWER pre-defines an extensible struc- ture where an optional input parameters are passed in order to modify to the standard OPF [60]. This enabled users to modify the problem formulation while still using MATPOWER pre-compiled solvers to solve the problem. Paper [60] explains this extensible opf formulation feature of MATPOWER. The extended formulation for minimization function can be written in the following form.

$$min_{x,z} f(x) + f_u\,(x, z)$$

MATPOWER allows three major operations based on the extended function f_u namely User-defined Costs, User-defined Constraints, and User-defined Variables. These extended formulations can written on top of pre-defined formulation to achieve multi objective optimization function.

Matpower includes four different algorithms for solving the AC power flow problem. The default solver uses Newton Raphson iteration process to compute optimal power flow by forming a Jacobian matrix and updating it at every iteration. The mismatch $g(x)$ in each step is used to compute optimal power flow by forming the Jacobian based on the sensitivities of these mismatches to changes in x and solving for an updated value of x by factorizing this Jacobian. Other optimization solvers in MATPOWER uses algorithms from fast-decoupled XB, fast-decoupled BX, and Gauss-Seidel method. User has the option to choose the solver in MATPOWER depending on specific needs of speed and accuracy.

4.3.1 MATPOWER Functions used in this work

i Conversition of PSS/E raw file into MATPOWER case struct (`psse2mpc()`)

MATPOWER function `psse2mpc('rawcasefile.raw')` is used to convert PSS/E .raw data file into MATPOWER case struct. Input argument required for this function is the path of .raw file. The function returns the converted file in the form of a MATPOWER case struct which can be saved in the required directory using another function `savecase()`.

ii Standard AC OPF (`runopf()`)

MATPOWER function `runopf('casefile.m')` is used to execute a standard AC OPF on a case file. The only input argument required for this function is `casefile.m`. If requested, the function returns the solution of optimal power flow in a results struct which could be used later to analysis. OPF result consisting of generator, bus, and branch details are saved in the results struct as `results.gen,` `results.bus,` and `results.branch` respectively.

The MATPOWER manual [59] explains how the program calculates Optimal Power flow. The objective function of optimization is to minimize the summation of individual polynomial cost functions f_P^i and f_Q^i as per the expression given below (Equation 4.2).

$$min_{\theta,V_m,P_g,Q_g} \sum_{i=1}^{n_g} f_P^i(p_g^i) + f_Q^i(q_g^i) \tag{4.2}$$

Minimization in Equation 4.2 is subject to equality such as real and reactive power balance equations and inequality constraints such as branch flow limits, upper and lower limits on all bus voltage magnitude, generator bounds and so forth. The standard OPF formulation using `runopf()` however has no mechanism for completely shutting down generators which are very expensive to operate. If we have to allow the program to shut down these expensive units and find a least cost commitment and dispatch, we have to use Unit De-commitment Algorithm. This is implemented using `runuopf()` instead and this gives the capability to simulation for unit decommitment.

iii Limiting Interface Flow (`toggle_iflims()`)

Interface limits are enabled in MATPOWER by enabling an extension in MATPOWER before running actual optimization simulation. It is implemented in `(toggle_iflims(mpc, 'on')`. Here mpc is the actual MATPOWER case struct and $'on'$ is used to turn the limits on . IF $f_k(\theta)$ is the interface flow in the system, this extension add to the OPF problem a set of constraints on the interface flow as shown below Equation 4.3.

$$F_k^{min} \leq f_k\left(\theta\right) \leq F_k^{max} \qquad \forall k \in I_f \tag{4.3}$$

where F_k^{min} and F_k^{max} are the lower and upper bounds of the interface limits. Interface map specifying the transmission lines which are under each interface and their limits has to be specified in the case struct before enabling the limit.

iv Extending OPF formulation (`add_userfcn()`)

As explained in the introduction, MATPOWER give access to users to modify the standard OPF formulation to include additional constraints and requirements. This could be done either using direct specification as explained in MATPOWER manual [59]or by using callback functions. The standard format for adding user function is given in Equation 4.4

```
mpc= add_userfcn(mpc, 'formulation', @userfcn_reserves_formulation);
```
(4.4)

There are basically three user function models which could be used to modify OPF formulation, namely `add_vars`, `add_constraints`, and `add_costs`. Firstly, `add_var()` is used to define and access variable sets and to name them so as to use them as a named block. `add_constraints()` is used to define constraints, which modifies the OPF formulation. Lastly, `add_costs()` is used to add a user defined cost to any parameters of optimization so that this additional cost of including these parameters is taken care of while formulating optimization problem. Syntax for using these functions and their functionality are detailed in MATPOWER manual [59].

Chapter 5

Simulation and Results

This chapter presents the simulation results of a six bus system and fourteen bus system and compares the performance of these systems in forward and spot market. There are two simulation for each case study , one without distributed generation and other with distributed generation included. Forward Market calculations are based on the above mentioned first simulation whereas, spot market calculation is based on second simulation. The methodology used for these calculations is given in Chapter 3. For each test system, input files for running the program and the results of every simulation are presented in the following sections.

5.1 Case Study on a Six Bus System

The six bus system used for this study consists of three generators at bus 1, 2, and 3 and three loads at bus 4, 5,and 6. The load varies throughout the 24 hour time period. There are total eleven branches in the system. Distributed generators are placed at the load buses and are included only during spot market calculation.

5.1.1 Input data

The following subsections describes the system specifications given as input files to run the program on a six bus system in Matlab.

i Case File

There are seven parameters that needs to be given as input to MATPOWER case struct; namely baseMVA, bus, gen, branch, gencost, if.map, and if.lims. They represents system base MVA, bus details, generator specifications, branch details, generator cost function, branch in each interface mapping, and interface limits specification respectively. Each one of these quantities is explained in detail in the following section. The file format used to represent these parameter is included in the Appendix.

baseMVA

Matrix 'mpc.baseMVA' in the case struct is used to represent system base MVA. Base MVA is set to 100 MVA in all simulations.

Bus Specifications

There are six buses in the system and are identified using the bus number. Initial P and Q load is given by second and third columns in the listing. Voltage magnitudes and angles are given by twelfth and thirteenth columns respectively. Bus matrix in case file is given by Listing 5.1

Listing 5.1: Bus data input of the six bus system

```
%%- bus data
% bus_i type Pd Qd Gs Bs area Vm Va baseKV zone Vmax Vmin
mpc.bus = [
1    3    0    0    0    0    1    1    0    138  1    1.05     0.95;
2    2    0    0    0    0    1    1    0    138  1    1.05     0.95;
3    2    0    0    0    0    1    1    0    138  1    1.05     0.95;
4    1    70   70   0    0    1    1    0    138  1    1.05     0.95;
5    1    70   70   0    0    1    1    0    138  1    1.05     0.95;
6    1    70   70   0    0    1    1    0    138  1    1.05     0.95;
];
```

Branch Rating

The eleven branches of the system are represented using the input matrix in case file 'mpc.branch' given by Listing 5.2. Each branch is represented using from and to bus it connects. Short term and long term ratings are specified by columns 6 to 9. Table 5.1 shows the branch rating used in the simulation.

Branch ID	From Bus	To Bus	Line R (p.u)	Line X (p.u)	Charging B (p.u)	Rating (MW)	Status
1	1	2	0.1	0.2	0.04	30	1
2	1	4	0.05	0.2	0.04	50	1
3	1	5	0.08	0.3	0.06	40	1
4	2	3	0.05	0.25	0.06	20	1
5	2	4	0.05	0.1	0.02	40	1
6	2	5	0.1	0.3	0.04	20	1
7	2	6	0.07	0.2	0.05	30	1
8	3	5	0.12	0.26	0.05	20	1
9	3	6	0.02	0.1	0.02	60	1
10	4	5	0.2	0.4	0.08	20	1
11	5	6	0.1	0.3	0.06	20	1

Table 5.1: Six Bus system branch rating

Listing 5.2: Branch data input of the six bus system

```
%% branch data
% fbus tbus r x b rateA rateB rateC ratio angle status angmin angmax
mpc.branch = [
1    2    0.1      0.2      0.04     30   30   30   0    0    1    -360     360;
1    4    0.05     0.2      0.04     50   50   50   0    0    1    -360     360;
1    5    0.08     0.3      0.06     40   40   40   0    0    1    -360     360;
2    3    0.05     0.25     0.06     20   20   20   0    0    1    -360     360;
2    4    0.05     0.1      0.02     40   40   40   0    0    1    -360     360;
2    5    0.1      0.3      0.04     20   20   20   0    0    1    -360     360;
2    6    0.07     0.2      0.05     30   30   30   0    0    1    -360     360;
3    5    0.12     0.26     0.05     20   20   20   0    0    1    -360     360;
3    6    0.02     0.1      0.02     60   60   60   0    0    1    -360     360;
4    5    0.2      0.4      0.08     20   20   20   0    0    1    -360     360;
5    6    0.1      0.3      0.06     20   20   20   0    0    1    -360     360;
];
```

Generator data and generator cost function

The three utility generators and distributed generation connected to the system and their cost is specified using input matrix in case file 'mpc.gen' and 'mpc.gencost' given by Listing 5.3 and Listing 5.4.Maximum and minimum limits of generators, Generator bus, current P and Q dispatch are input here to the system. Utility generators are given by first three rows whereas, distributed generators are given by last three rows

Listing 5.3: Generator data input (PG and DG) of the six bus system

```
%% generator data
%    bus Pg   Qg   Qmax     Qmin     Vg   mBase    status   Pmax     Pmin     Pc1  Pc2  Qc1min
%        Qc1max   Qc2min   Qc2max   ramp_agc     ramp_10  ramp_30  ramp_q   apf
mpc.gen = [
1    0    0    100  -100     1    100  1    200  50    0   0    0    0    0    0    0    0    0    0    0;
2    50   0    100  -100     1    100  1    150  37.5  0   0    0    0    0    0    0    0    0    0    0;
3    60   0    100  -100     1    100  1    180  45    0   0    0    0    0    0    0    0    0    0    0;
4    0    0    100    0      1    100  1    100   0    0   0    0    0    0    0    0    0    0    0    0;
5    0    0    100    0      1    100  1    100   0    0   0    0    0    0    0    0    0    0    0    0;
6    0    0    100    0      1    100  1    100   0    0   0    0    0    0    0    0    0    0    0    0;
];
```

Quadratic cost function of utiltiy generator and distributed generator are specified using input matrix in case file'mpc.gencost'. Last three columns of Listing 5.4 represents $a.\mathrm{P_g}^2, b.\mathrm{P_g}, c$ of the quadratic cost function respectively.

Listing 5.4: Generator cost input of the six bus system

```
%%-----  OPF Data  -----%%
%%-- generator cost data
%    1    startup shutdown     n    x1   y1   ...  xn   yn
%    2    startup shutdown     n    c(n-1)    ...  c0
mpc.gencost = [
2    0    0    3    0    41.47    0;
2    0    0    3    0    25.77    0;
2    0    0    3    0    39.3     0;
2    0    0    3    0.003    43    0;
2    0    0    3    0.003    43    0 ;
2    0    0    3    0.003    43    0 ;
];
```

Interface Limits and Mapping

Interfaces of system is specified using input matrix in case file 'mpc.if.lims' and 'mpc.if.map'. Listing 5.5 inputs the interface mappping and interface limits to the system.

Listing 5.5: Interface input of the six bus system

```
%%-----  Interface Flow Limit Data  -----%%
% ifnum branchidx (negative defines opposite direction)
mpc.if.map = [
1   2;  %% 1 : area 1 imports
1   5;
2   7;  %% 2 : area 2 imports
2   8;
2   9;

];
%% (negative and positive directions can be different)
%   ifnum   lower   upper
mpc.if.lims = [
1   -78 78; %% area 1 imports
2   -95 95  %% area 2 imports
```

ii System Load Profile

For the six bus system, system load is assumed to be equally distributed among all load buses. 24 hour day ahead load is expected for the market simulation.24 hour load profile is given input file for as a .csv file. displays the file format used to represent system loads.

Listing 5.6: System Load of the six bus system in .csv file format

```
150,140,120,135,150,170,180,210,220,240,250,255,260,260,255,270,270,
255,240,230,220,180,150,130
```

5.1.2 Results

The program takes aforementioned input data files and produces the final results in `.csv` data format. This section outlines the results generated by the program and are presented in the form of a table for easy understanding. After the program reads in all the input files, it starts to calculate the preliminary parameters necessary for later processes.

i Generator Shift Factor

A generator shift factor on a transmission line corresponding to the change in power flow with a unit power injection at a bus i. It is calculated based on Equation 2.25-2.26. The calculated GSF for a six bus system is presented below.

	Bus1	Bus2	Bus3	Bus4	Bus5	Bus6
Line1	0	-0.471	-0.403	-0.315	-0.322	-0.406
Line2	0	-0.315	-0.295	-0.504	-0.271	-0.296
Line3	0	-0.214	-0.303	-0.181	-0.407	-0.298
Line4	0	0.054	-0.342	0.016	-0.106	-0.191
Line5	0	0.311	0.215	-0.379	0.101	0.221
Line6	0	0.099	-0.034	0.029	-0.193	-0.027
Line7	0	0.064	-0.242	0.019	-0.125	-0.410
Line8	0	0.062	0.289	0.018	-0.121	0.153
Line9	0	-0.008	0.369	-0.002	0.015	-0.343
Line10	0	-0.003	-0.079	0.117	-0.170	-0.075
Line11	0	-0.056	-0.127	-0.017	0.110	-0.247

Table 5.2: GSF of the six bus system

ii Forward Transaction Generator Dispatch

The program determines marginal cost of each generator from the case file and run a multilevel optimal power flow, with objectives to minimize load shedding and minimum cost of production and transmission. The program commits all three generators G1,G2, and G3 to satisfy hourly load demand with objectives stated above. Table 5.3 shows the generator dispatch in forward market. Column 2 gives the expected system load at various hour of the day and column 3 shows the minimum load shedding calculated. Hours 11-18 need load shedding for the program to converge and for power flows to stay in the levels that system operation is secure. The load shedding calculated here is used to calculate load in forward and spot market using Equation 3.3. The optimization program also verifies the power flow before the final dispatch. Table 5.4 lists the transmission line power flows and Table 5.5 lists the percentage power flows on rated capacity corresponding to the dispatch patterns shown in Table 5.3.

Hour	System Load	Load Shedding (MW)	G1 (MW)	G2 (MW)	G3 (MW)	Utility Capability / Production (MW)
1	150	0	50	56.846	45	151.85
2	140	0	58.13	85.74	0	143.87
3	120	0	0	76.655	45	121.66
4	135	0	50	87.382	0	137.38
5	150	0	50	56.846	45	151.85
6	170	0	50	77.382	45	172.38
7	180	0	50	87.698	45	182.7
8	210	0	75.588	84.397	54.339	214.32
9	220	0	84.497	80.011	60.202	224.71
10	240	0	105.82	69.694	69.994	245.51
11	250	10	107.07	69.193	69.228	245.49
12	255	14.025	110.27	67.666	68.554	246.49
13	260	18.2	110.67	67.313	69.355	247.34
14	260	18.2	110.67	67.313	69.355	247.34
15	255	14.025	110.27	67.666	68.554	246.49
16	270	28.35	110.15	67.57	69.464	247.18
17	270	28.35	110.15	67.57	69.464	247.18
18	255	14.025	110.27	67.666	68.554	246.49
19	240	0	105.82	69.694	69.994	245.51
20	230	0	93.445	75.62	66.075	235.14
21	220	0	84.497	80.011	60.202	224.71
22	180	0	50	87.698	45	182.7
23	150	0	50	56.846	45	151.85
24	130	0	0	87.172	45	132.17

Table 5.3: Generator Dispatch

Hour	Branch Id (MW)										
	1	2	3	4	5	6	7	8	9	10	11
1	6.5855	23.827	19.587	1.9962	29.021	14.024	18.342	13.243	33.751	2.19	1.6633
2	7.0988	25.851	25.181	18.497	26.933	17.024	29.5	3.0285	15.298	5.1407	2.5486
3	11.876	6.0297	5.6858	0.28974	35.42	14.461	14.608	15.008	30.281	0.81521	4.5761
4	4.9514	22.478	22.57	18.392	27.849	17.238	28.703	3.3011	14.929	4.6878	1.9805
5	6.5855	23.827	19.587	1.9962	29.021	14.024	18.342	13.243	33.751	2.19	1.6633
6	4.1657	24.651	21.183	5.1392	35.758	17.441	23.19	14.241	35.886	2.8655	1.8229
7	2.9289	25.077	21.994	6.7081	39.135	19.149	25.624	14.737	36.951	3.2093	1.8983
8	10.351	35.39	29.847	6.3233	39.801	19.892	28.216	16.895	43.746	3.7868	1.0908
9	13.532	38.819	32.146	5.0097	39.818	19.893	28.23	18.081	47.117	3.7853	1.0843
10	21.455	46.726	37.64	2.806	39.021	19.888	28.668	19.658	53.138	3.9964	0.76017
11	21.998	47.102	37.97	2.9887	38.719	19.887	28.832	19.361	52.851	4.0761	0.64088
12	23.364	48.121	38.785	3.2422	38.117	19.843	29.065	19.054	52.737	4.1641	0.42722
13	23.504	48.298	38.867	3.019	38.201	19.841	28.992	19.236	53.134	4.1419	0.47212
14	23.504	48.298	38.867	3.019	38.201	19.841	28.992	19.236	53.134	4.1419	0.47212
15	23.364	48.121	38.785	3.2422	38.117	19.843	29.065	19.054	52.737	4.1641	0.42722
16	23.281	48.134	38.736	2.9797	38.301	19.849	28.957	19.286	53.153	4.1281	0.50651
17	23.281	48.134	38.736	2.9797	38.301	19.849	28.957	19.286	53.153	4.1281	0.50651
18	23.364	48.121	38.785	3.2422	38.117	19.843	29.065	19.054	52.737	4.1641	0.42722
19	21.455	46.726	37.64	2.806	39.021	19.888	28.668	19.658	53.138	3.9964	0.76017
20	16.732	42.261	34.452	3.6937	39.834	19.894	28.244	19.268	50.491	3.7848	1.0779
21	13.532	38.819	32.146	5.0097	39.818	19.893	28.23	18.081	47.117	3.7853	1.0843
22	2.9289	25.077	21.994	6.7081	39.135	19.149	25.624	14.737	36.951	3.2093	1.8983
23	6.5855	23.827	19.587	1.9962	29.021	14.024	18.342	13.243	33.751	2.19	1.6633
24	13.268	6.4985	6.5664	1.5794	38.994	16.209	17.122	15.318	31.255	1.319	4.6196

Table 5.4: Branch Flow without connecting Distributed Generator

Hour	Branch Id										
	1	2	3	4	5	6	7	8	9	10	11
1	21.952	47.655	48.968	9.9808	72.552	70.118	61.141	66.216	56.252	10.95	8.3165
2	23.663	51.702	62.952	92.487	67.333	85.119	98.335	15.142	25.497	25.703	12.743
3	39.586	12.059	14.215	1.4487	88.55	72.307	48.694	75.042	50.469	4.076	22.881
4	16.505	44.957	56.426	91.96	69.623	86.192	95.678	16.506	24.881	23.439	9.9023
5	21.952	47.655	48.968	9.9808	72.552	70.118	61.141	66.216	56.252	10.95	8.3165
6	13.886	49.303	52.957	25.696	89.395	87.205	77.299	71.206	59.81	14.328	9.1143
7	9.763	50.154	54.986	33.54	97.837	95.745	85.412	73.685	61.584	16.046	9.4917
8	34.504	70.78	74.618	31.617	99.503	99.458	94.052	84.476	72.91	18.934	5.454
9	45.107	77.639	80.364	25.049	99.545	99.463	94.1	90.406	78.528	18.926	5.4213
10	71.516	93.453	94.1	14.03	97.552	99.438	95.56	98.289	88.563	19.982	3.8009
11	73.327	94.203	94.925	14.944	96.797	99.434	96.108	96.807	88.086	20.381	3.2044
12	77.881	96.242	96.964	16.211	95.292	99.214	96.884	95.272	87.895	20.82	2.1361
13	78.348	96.596	97.169	15.095	95.503	99.206	96.641	96.18	88.557	20.709	2.3606
14	78.348	96.596	97.169	15.095	95.503	99.206	96.641	96.18	88.557	20.709	2.3606
15	77.881	96.242	96.964	16.211	95.292	99.214	96.884	95.272	87.895	20.82	2.1361
16	77.602	96.267	96.841	14.898	95.753	99.247	96.523	96.43	88.588	20.64	2.5325
17	77.602	96.267	96.841	14.898	95.753	99.247	96.523	96.43	88.588	20.64	2.5325
18	77.881	96.242	96.964	16.211	95.292	99.214	96.884	95.272	87.895	20.82	2.1361
19	71.516	93.453	94.1	14.03	97.552	99.438	95.56	98.289	88.563	19.982	3.8009
20	55.774	84.522	86.13	18.468	99.585	99.47	94.148	96.342	84.152	18.924	5.3895
21	45.107	77.639	80.364	25.049	99.545	99.463	94.1	90.406	78.528	18.926	5.4213
22	9.763	50.154	54.986	33.54	97.837	95.745	85.412	73.685	61.584	16.046	9.4917
23	21.952	47.655	48.968	9.9808	72.552	70.118	61.141	66.216	56.252	10.95	8.3165
24	44.226	12.997	16.416	7.8969	97.486	81.045	57.072	76.588	52.092	6.5952	23.098

Table 5.5: Percentage Line loading (Percentage of branch Flow on its rated capacity) without connecting Distributed Generator

iii Spot Market Generator Dispatch

After the calculation of forward market optimization, the program optimizes the transactions in spot market. The load in forward and spot market determined from previous section is used here to run the program. The program optimizes the purchase of power from DG to maximize utility profit. The program commits utility generators G1,G2, and G3 first to satisfy hourly load demand; if it cannot satisfy the load demand it commits the distributed generator placed at bus 4,5,6 to satisfy the load demand. The Table 5.6 shows the minimum purchased power from DG at various buses to satisfy load demand. During hours 1-10 and 19-24 utility is self sufficient to meet its demand. However, during hour 11-18 requires utility to purchase from DG for the program to converge and for power flows to stay in the levels that system operation is secure. The optimization program also verifies the transmission line power flow before the final dispatch. Table 5.7 lists the transmission line power flows and Table 5.8 lists the percentage power flows on rated capacity corresponding to the dispatch patterns shown in Table 5.6.

Hour	Pg1 (MW)	Pg2 (MW)	Pg3 (MW)	Bus 4 (MW)	Bus 5 (MW)	Bus 6 (MW)	Pg Total (MW)	Dg Total (MW)
1	50	56.846	45	0	0	0	151.85	0
2	58.13	85.74	0	0	0	0	143.87	0
3	0	76.655	45	0	0	0	121.66	0
4	50	87.382	0	0	0	0	137.38	0
5	50	56.846	45	0	0	0	151.85	0
6	50	77.382	45	0	0	0	172.38	0
7	50	87.698	45	0	0	0	182.7	0
8	75.588	84.397	54.339	0	0	0	214.32	0
9	84.497	80.011	60.202	0	0	0	224.71	0
10	105.82	69.694	69.994	0	0	0	245.51	0
11	112.68	67.49	68.74	0	5.2441	1.414	248.91	6.6581
12	111.45	69.35	68.733	1.9554	5.2377	3.8959	249.53	11.089
13	111.45	69.35	68.733	3.6221	6.9044	5.5626	249.53	16.089
14	111.45	69.35	68.733	3.6221	6.9044	5.5626	249.53	16.089
15	111.45	69.35	68.733	1.9554	5.2377	3.8959	249.53	11.089
16	111.45	69.35	68.733	6.9554	10.238	8.8959	249.53	26.089
17	111.45	69.35	68.733	6.9554	10.238	8.8959	249.53	26.089
18	111.45	69.35	68.733	1.9554	5.2377	3.8959	249.53	11.089
19	105.82	69.694	69.994	0	0	0	245.51	0
20	93.445	75.62	66.075	0	0	0	235.14	0
21	84.497	80.011	60.202	0	0	0	224.71	0
22	50	87.698	45	0	0	0	182.7	0
23	50	56.846	45	0	0	0	151.85	0
24	0	87.172	45	0	0	0	132.17	0
Total	1850.60	1772.63	1290.68	27.02	55.24	42.02	4913.91	124.28

Table 5.6: Minimum power purchase from DG to avoid Load shedding

Hour	Branch Id (MW)										
	1	2	3	4	5	6	7	8	9	10	11
1	6.5855	23.827	19.587	1.9962	29.021	14.024	18.342	13.243	33.751	2.19	1.6633
2	7.0988	25.851	25.181	18.497	26.933	17.024	29.5	3.0285	15.298	5.1407	2.5486
3	11.876	6.0297	5.6858	0.28974	35.42	14.461	14.608	15.008	30.281	0.81521	4.5761
4	4.9514	22.478	22.57	18.392	27.849	17.238	28.703	3.3011	14.929	4.6878	1.9805
5	6.5855	23.827	19.587	1.9962	29.021	14.024	18.342	13.243	33.751	2.19	1.6633
6	4.1657	24.651	21.183	5.1392	35.758	17.441	23.19	14.241	35.886	2.8655	1.8229
7	2.9289	25.077	21.994	6.7081	39.135	19.149	25.624	14.737	36.951	3.2093	1.8983
8	10.351	35.39	29.847	6.3233	39.801	19.892	28.216	16.895	43.746	3.7868	1.0908
9	13.532	38.819	32.146	5.0097	39.818	19.893	28.23	18.081	47.117	3.7853	1.0843
10	21.455	46.726	37.64	2.806	39.021	19.888	28.668	19.658	53.138	3.9964	0.76017
11	24.285	49.539	38.855	3.1884	39.161	19.341	29.321	18.507	53.417	3.5309	0.25558
12	23.523	49.046	38.878	3.3254	39.618	19.835	29.33	18.97	53.083	3.7791	0.24258
13	23.523	49.046	38.878	3.3254	39.618	19.835	29.33	18.97	53.083	3.7791	0.24258
14	23.523	49.046	38.878	3.3254	39.618	19.835	29.33	18.97	53.083	3.7791	0.24258
15	23.523	49.046	38.878	3.3254	39.618	19.835	29.33	18.97	53.083	3.7791	0.24258
16	23.523	49.046	38.878	3.3254	39.618	19.835	29.33	18.97	53.083	3.7791	0.24258
17	23.523	49.046	38.878	3.3254	39.618	19.835	29.33	18.97	53.083	3.7791	0.24258
18	23.523	49.046	38.878	3.3254	39.618	19.835	29.33	18.97	53.083	3.7791	0.24258
19	21.455	46.726	37.64	2.806	39.021	19.888	28.668	19.658	53.138	3.9964	0.76017
20	16.732	42.261	34.452	3.6937	39.834	19.894	28.244	19.268	50.491	3.7848	1.0779
21	13.532	38.819	32.146	5.0097	39.818	19.893	28.23	18.081	47.117	3.7853	1.0843
22	2.9289	25.077	21.994	6.7081	39.135	19.149	25.624	14.737	36.951	3.2093	1.8983
23	6.5855	23.827	19.587	1.9962	29.021	14.024	18.342	13.243	33.751	2.19	1.6633
24	13.268	6.4985	6.5664	1.5794	38.994	16.209	17.122	15.318	31.255	1.319	4.6196

Table 5.7: Branch Flow with Distributed Generator connected

Hour	Branch Id										
	1	2	3	4	5	6	7	8	9	10	11
1	21.952	47.655	48.968	9.9808	72.552	70.118	61.141	66.216	56.252	10.95	8.3165
2	23.663	51.702	62.952	92.487	67.333	85.119	98.335	15.142	25.497	25.703	12.743
3	39.586	12.059	14.215	1.4487	88.55	72.307	48.694	75.042	50.469	4.076	22.881
4	16.505	44.957	56.426	91.96	69.623	86.192	95.678	16.506	24.881	23.439	9.9023
5	21.952	47.655	48.968	9.9808	72.552	70.118	61.141	66.216	56.252	10.95	8.3165
6	13.886	49.303	52.957	25.696	89.395	87.205	77.299	71.206	59.81	14.328	9.1143
7	9.763	50.154	54.986	33.54	97.837	95.745	85.412	73.685	61.584	16.046	9.4917
8	34.504	70.78	74.618	31.617	99.503	99.458	94.052	84.476	72.91	18.934	5.454
9	45.107	77.639	80.364	25.049	99.545	99.463	94.1	90.406	78.528	18.926	5.4213
10	71.516	93.453	94.1	14.03	97.552	99.438	95.56	98.289	88.563	19.982	3.8009
11	80.95	99.079	97.137	15.942	97.902	96.706	97.738	92.534	89.028	17.655	1.2779
12	78.409	98.092	97.194	16.627	99.044	99.177	97.768	94.851	88.471	18.895	1.2129
13	78.409	98.092	97.194	16.627	99.044	99.177	97.768	94.851	88.471	18.895	1.2129
14	78.409	98.092	97.194	16.627	99.044	99.177	97.768	94.851	88.471	18.895	1.2129
15	78.409	98.092	97.194	16.627	99.044	99.177	97.768	94.851	88.471	18.895	1.2129
16	78.409	98.092	97.194	16.627	99.044	99.177	97.768	94.851	88.471	18.895	1.2129
17	78.409	98.092	97.194	16.627	99.044	99.177	97.768	94.851	88.471	18.895	1.2129
18	78.409	98.092	97.194	16.627	99.044	99.177	97.768	94.851	88.471	18.895	1.2129
19	71.516	93.453	94.1	14.03	97.552	99.438	95.56	98.289	88.563	19.982	3.8009
20	55.774	84.522	86.13	18.468	99.585	99.47	94.148	96.342	84.152	18.924	5.3895
21	45.107	77.639	80.364	25.049	99.545	99.463	94.1	90.406	78.528	18.926	5.4213
22	9.763	50.154	54.986	33.54	97.837	95.745	85.412	73.685	61.584	16.046	9.4917
23	21.952	47.655	48.968	9.9808	72.552	70.118	61.141	66.216	56.252	10.95	8.3165
24	44.226	12.997	16.416	7.8969	97.486	81.045	57.072	76.588	52.092	6.5952	23.098

Table 5.8: Percentage Line loading (Percentage of branch Flow on its rated capacity) with Distributed Generator connected

iv Binding Constraints

After the calculation of generator dispatch in forward and spot market, binding constraints in the transmission lines are determined. Forward subscription price and spot price are determined based on LMP at various buses which is calculated based on binding constraints in transmission lines.Table 5.10 and Table 5.12 show the binding constraints for forward and spot market at various hours of the day. It is determined from optimization result of forward and spot market. Load hour, branch ID, actual power flow and the rating of lines, percentage of rated capacity, and line/ interface identifier are the various parameters shown in the tables. Interface and line are represented as 1 and 0 respectively.

Hour	Branch Id	Power Flow (MW)	Branch Ratings (MW)	Percentage Line Loading (%)	Line (0) Interface(1)
2	7	29.5	30	98.335	0
8	5	39.801	40	99.503	0
8	6	19.892	20	99.458	0
9	5	39.818	40	99.545	0
9	6	19.893	20	99.463	0
10	6	19.888	20	99.438	0
10	8	19.658	20	98.289	0
10	2	99.997	100	99.997	1
11	6	19.887	20	99.434	0
11	2	99.592	100	99.592	1
12	6	19.843	20	99.214	0
12	2	99.408	100	99.408	1
13	6	19.841	20	99.206	0
13	2	99.902	100	99.902	1
14	6	19.841	20	99.206	0

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Hour	Branch Id	Power Flow (MW)	Branch Ratings (MW)	Percentage Line Loading (%)	Line (0) Interface(1)
14	2	99.902	100	99.902	1
15	6	19.843	20	99.214	0
15	2	99.408	100	99.408	1
16	6	19.849	20	99.247	0
16	2	99.935	100	99.935	1
17	6	19.849	20	99.247	0
17	2	99.935	100	99.935	1
18	6	19.843	20	99.214	0
18	2	99.408	100	99.408	1
19	6	19.888	20	99.438	0
19	8	19.658	20	98.289	0
19	2	99.997	100	99.997	1
20	5	39.834	40	99.585	0
20	6	19.894	20	99.47	0
21	5	39.818	40	99.545	0
21	6	19.893	20	99.463	0

Table 5.10: Binding Constraints without Distributed Generation

Hour	Branch Id	Power Flow (MW)	Branch Ratings (MW)	Percentage Line Loading (%)	Line (0) Interface(1)
2	7	29.5	30	98.335	0
8	5	39.801	40	99.503	0
8	6	19.892	20	99.458	0
9	5	39.818	40	99.545	0
9	6	19.893	20	99.463	0
10	6	19.888	20	99.438	0
10	8	19.658	20	98.289	0
10	2	99.997	100	99.997	1
11	2	49.539	50	99.079	0
11	1	86.864	88	98.709	1
11	2	99.796	100	99.796	1
12	2	49.046	50	98.092	0
12	5	39.618	40	99.044	0
12	6	19.835	20	99.177	0
12	1	86.824	88	98.663	1
12	2	99.922	100	99.922	1
13	2	49.046	50	98.092	0
13	5	39.618	40	99.044	0
13	6	19.835	20	99.177	0
13	1	86.824	88	98.663	1
13	2	99.922	100	99.922	1
14	2	49.046	50	98.092	0
14	5	39.618	40	99.044	0
14	6	19.835	20	99.177	0
14	1	86.824	88	98.663	1

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Hour	Branch Id	Power Flow (MW)	Branch Ratings (MW)	Percentage Line Loading (%)	Line (0) Interface(1)
14	2	99.922	100	99.922	1
15	2	49.046	50	98.092	0
15	5	39.618	40	99.044	0
15	6	19.835	20	99.177	0
15	1	86.824	88	98.663	1
15	2	99.922	100	99.922	1
16	2	49.046	50	98.092	0
16	5	39.618	40	99.044	0
16	6	19.835	20	99.177	0
16	1	86.824	88	98.663	1
16	2	99.922	100	99.922	1
17	2	49.046	50	98.092	0
17	5	39.618	40	99.044	0
17	6	19.835	20	99.177	0
17	1	86.824	88	98.663	1
17	2	99.922	100	99.922	1
18	2	49.046	50	98.092	0
18	5	39.618	40	99.044	0
18	6	19.835	20	99.177	0
18	1	86.824	88	98.663	1
18	2	99.922	100	99.922	1
19	6	19.888	20	99.438	0
19	8	19.658	20	98.289	0
19	2	99.997	100	99.997	1

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Hour	Branch Id	Power Flow (MW)	Branch Ratings (MW)	Percentage Line Loading (%)	Line (0) Interface(1)
20	5	39.834	40	99.585	0
20	6	19.894	20	99.47	0
21	5	39.818	40	99.545	0
21	6	19.893	20	99.463	0

Table 5.12: Binding Constraints with Distributed Generation connected

v Forward market Transactive Accounting

Table 5.13- 5.14 shows the transactive accounting for forward market. Table 5.13 shows the total system load along with the load shedding expected in Forward market. Next the cost of energy at each bus, which is the LMP of the system is shown for entire 24 hour load. One could notice that LMP at every bus is different. This is due to the fact that binding constraints of different lines and power loss of transmission lines are different. If there is no transmission line congestion, the LMP at every bus would be same. The price of power at each bus is calculated by solving linear equations based on the Incremental Flow Equation and Incremental Price Equation described in Chapter 3. The energy price from Table 5.13 is used in Table 5.14 to calculate the consumer payments at various bus. Bus 4, 5, and 6 corresponds to load buses of the system, and consumer payments are calculated based on the total load and LMP at each of these buses. Utility dispatch and total minimum production cost are the result of optimization performed in the previous section. Net Profit of each transaction is calculated as the difference of total consumer payment and production cost.

Hour	System Load (MW)	Load Shed (MW)	Load in FT (MW)	LMP ($ per MW)					
				Bus 1	Bus 2	Bus 3	Bus 4	Bus 5	Bus 6
1	150	0	150	41.47	43.039	43.788	42.936	43.207	43.811
2	140	0	140	28.605	26.745	41.496	28.752	35.536	49.346
3	120	0	120	39.3	40.787	41.496	40.689	40.946	41.518
4	135	0	135	41.47	43.039	43.788	42.936	43.207	43.811
5	150	0	150	41.47	43.039	43.788	42.936	43.207	43.811
6	170	0	170	41.47	43.039	43.788	42.936	43.207	43.811
7	180	0	180	41.47	43.039	43.788	42.936	43.207	43.811
8	210	0	210	41.47	26.745	41.496	49.597	57.688	40.707
9	220	0	220	41.47	26.745	41.496	49.597	57.688	40.707
10	240	0	240	41.47	26.745	41.496	38.155	74.96	63.858
11	250	10	240	41.47	26.745	41.496	38.155	74.96	58.22
12	255	14.025	240.98	41.47	26.745	41.496	38.155	74.96	58.22
13	260	18.2	241.8	41.47	26.745	41.496	38.155	74.96	58.22
14	260	18.2	241.8	41.47	26.745	41.496	38.155	74.96	58.22
15	255	14.025	240.98	41.47	26.745	41.496	38.155	74.96	58.22
16	270	28.35	241.65	41.47	26.745	41.496	38.155	74.96	58.22
17	270	28.35	241.65	41.47	26.745	41.496	38.155	74.96	58.22
18	255	14.025	240.98	41.47	26.745	41.496	38.155	74.96	58.22
19	240	0	240	41.47	26.745	41.496	38.155	74.96	63.858
20	230	0	230	41.47	26.745	41.496	49.597	57.688	40.707
21	220	0	220	41.47	26.745	41.496	49.597	57.688	40.707
22	180	0	180	41.47	43.039	43.788	42.936	43.207	43.811
23	150	0	150	41.47	43.039	43.788	42.936	43.207	43.811
24	130	0	130	39.3	40.787	41.496	40.689	40.946	41.518

Table 5.13: LMP at various buses without DG in the system (Forward Subscription Cost)

Hour	System Load (MW)	Load Shedding (MW)	Utility Dispatch (MW)	Min. Prod. cost ($)	CP1 at Bus 4 ($)	CP2 at Bus 5 ($)	CP3 at Bus 6 ($)	Total CP ($)	Net Profit ($)
1	150	0	151.85	5306.9	2146.8	2160.3	2190.5	6497.7	1190.7
2	140	0	143.87	4620.2	1341.8	1658.4	2302.8	5302.9	682.74
3	120	0	121.66	3743.9	1627.6	1637.8	1660.7	4926.1	1182.2
4	135	0	137.38	4325.3	1932.1	1944.3	1971.5	5847.9	1522.6
5	150	0	151.85	5306.9	2146.8	2160.3	2190.5	6497.7	1190.7
6	170	0	172.38	5836.1	2433	2448.4	2482.6	7364	1527.9
7	180	0	182.7	6102	2576.1	2592.4	2628.6	7797.2	1695.2
8	210	0	214.32	7445.1	3471.8	4038.2	2849.5	10359	2914.3
9	220	0	224.71	7931.9	3637.1	4230.5	2985.1	10853	2920.8
10	240	0	245.51	8935.2	3052.4	5996.8	5108.6	14158	5222.6
11	250	10	245.49	8943.9	3052.4	5996.8	4657.6	13707	4762.8
12	255	14.02	246.49	9010.9	3064.8	6021.1	4676.5	13762	4751.6
13	260	18.2	247.34	9049.8	3075.3	6041.8	4692.5	13810	4759.7
14	260	18.2	247.34	9049.8	3075.3	6041.8	4692.5	13810	4759.7
15	255	14.02	246.49	9010.9	3064.8	6021.1	4676.5	13762	4751.6
16	270	28.35	247.18	9039.1	3073.4	6038	4689.6	13801	4761.8
17	270	28.35	247.18	9039.1	3073.4	6038	4689.6	13801	4761.8
18	255	14.02	246.49	9010.9	3064.8	6021.1	4676.5	13762	4751.6
19	240	0	245.51	8935.2	3052.4	5996.8	5108.6	14158	5222.6
20	230	0	235.14	8420.7	3802.4	4422.7	3120.8	11346	2925.4
21	220	0	224.71	7931.9	3637.1	4230.5	2985.1	10853	2920.8
22	180	0	182.7	6102	2576.1	2592.4	2628.6	7797.2	1695.2
23	150	0	151.85	5306.9	2146.8	2160.3	2190.5	6497.7	1190.7
24	130	0	132.17	4014.9	1763.2	1774.3	1799.1	5336.6	1321.7
Total	4940	145.18	4892	172420	65888	98264	81655	245807	73387

Table 5.14: Consumer Payment in Forward Subscription

vi Energy Cost

Table 5.15 presents the total energy cost at various bus in forward and spot market. Calculation of forward subscription cost was shown in previous sections. Here the focus is to calculate the spot price of various buses. Spot price is calculated using the incremental flow equation described in Chapter 3, considering utility and distributed generation, unlike forward subscription which considers only utility generation. By solving the linear equation for incremental flow equation nodal prices are determined.

	FS prices ($ per MW)						SP prices ($ per MW)					
Hour	Bus 1	Bus 2	Bus 3	Bus 4	Bus 5	Bus 6	Bus 1	Bus 2	Bus 3	Bus 4	Bus 5	Bus 6
1	41.47	43.039	43.788	42.936	43.207	43.811	41.47	43.039	43.788	42.936	43.207	43.811
2	28.605	26.745	41.496	28.752	35.536	49.346	28.103	26.745	38.967	28.386	33.998	45.43
3	39.3	40.787	41.496	40.689	40.946	41.518	39.3	40.787	41.496	40.689	40.946	41.518
4	41.47	43.039	43.788	42.936	43.207	43.811	41.47	43.039	43.788	42.936	43.207	43.811
5	41.47	43.039	43.788	42.936	43.207	43.811	41.47	43.039	43.788	42.936	43.207	43.811
6	41.47	43.039	43.788	42.936	43.207	43.811	41.47	43.039	43.788	42.936	43.207	43.811
7	41.47	43.039	43.788	42.936	43.207	43.811	41.47	43.039	43.788	42.936	43.207	43.811
8	41.47	26.745	41.496	49.597	57.688	40.707	36.539	26.745	35.527	44.523	44.804	35.073
9	41.47	26.745	41.496	49.597	57.688	40.707	36.539	26.745	35.527	44.523	44.804	35.073
10	41.47	26.745	41.496	38.155	74.96	63.858	31.629	26.745	41.496	30.962	44.804	45.43
11	41.47	26.745	41.496	38.155	74.96	58.22	41.47	41.563	41.496	44.523	43.843	45.439
12	41.47	26.745	41.496	38.155	74.96	58.22	41.47	26.745	41.496	44.535	44.837	45.455
13	41.47	26.745	41.496	38.155	74.96	58.22	41.47	26.745	41.496	44.545	44.847	45.466
14	41.47	26.745	41.496	38.155	74.96	58.22	41.47	26.745	41.496	44.545	44.847	45.466
15	41.47	26.745	41.496	38.155	74.96	58.22	41.47	26.745	41.496	44.535	44.837	45.455
16	41.47	26.745	41.496	38.155	74.96	58.22	41.47	26.745	41.496	44.566	44.868	45.487
17	41.47	26.745	41.496	38.155	74.96	58.22	41.47	26.745	41.496	44.566	44.868	45.487
18	41.47	26.745	41.496	38.155	74.96	58.22	41.47	26.745	41.496	44.535	44.837	45.455
19	41.47	26.745	41.496	38.155	74.96	63.858	31.629	26.745	41.496	30.962	44.804	45.43
20	41.47	26.745	41.496	49.597	57.688	40.707	36.539	26.745	35.527	44.523	44.804	35.073
21	41.47	26.745	41.496	49.597	57.688	40.707	36.539	26.745	35.527	44.523	44.804	35.073
22	41.47	43.039	43.788	42.936	43.207	43.811	41.47	43.039	43.788	42.936	43.207	43.811
23	41.47	43.039	43.788	42.936	43.207	43.811	41.47	43.039	43.788	42.936	43.207	43.811
24	39.3	40.787	41.496	40.689	40.946	41.518	39.3	40.787	41.496	40.689	40.946	41.518

Table 5.15: Forward Subscription and Spot Price Table

vii Transactive accounting in Spot market

Table 5.16 summarizes the total dispatch in forward and spot market calculated using the optimization technique proposed in this work. Load in forward and spot market are also presented in the table which is later used to calculate consumer payment in real time

Hour	System Load (MW)	PG Dispatch (MW)	DG Dispatch (MW)	Load in FS (MW)	Load in SP (MW)
1	150	151.85	0	150	0
2	140	143.87	0	140	0
3	120	121.66	0	120	0
4	135	137.38	0	135	0
5	150	151.85	0	150	0
6	170	172.38	0	170	0
7	180	182.7	0	180	0
8	210	214.32	0	210	0
9	220	224.71	0	220	0
10	240	245.51	0	240	0
11	250	248.91	6.6581	240	10
12	255	249.53	11.089	240.98	14.025
13	260	249.53	16.089	241.8	18.2
14	260	249.53	16.089	241.8	18.2
15	255	249.53	11.089	240.98	14.025
16	270	249.53	26.089	241.65	28.35
17	270	249.53	26.089	241.65	28.35
18	255	249.53	11.089	240.98	14.025
19	240	245.51	0	240	0
20	230	235.14	0	230	0
21	220	224.71	0	220	0
22	180	182.7	0	180	0
23	150	151.85	0	150	0
24	130	132.17	0	130	0
Total	4940.00	4913.91	124.28	4794.83	145.18

Table 5.16: Generator Dispatch in Forward and Spot Market

Table 5.16 shows the calculations the consumer payment in spot market as shown in Table 5.17. First the total cost to utility is calculated as the sum of production cost of utility generator and distributed generator. Next, total consumer payment is calculated as the sum of consumer payments in forward and spot market. Consumer payment in spot market is calculated based on the load in spot market calculated above. Net profit in real time is calculated as the difference of total consumer payment including the payment in forward subscription and spot price, and the total production cost of power.

Hour	System Load (MW)	DG Power Cost ($)	Pg Power Cost ($)	Total Cost to Utility ($)	CP in FS ($)	CP in SP ($)	Total CP ($)	Net Profit ($)
1	150	0	5306.9	5306.9	6497.7	0	6497.7	1190.7
2	140	0	4620.2	4620.2	5302.9	0	5302.9	682.74
3	120	0	3743.9	3743.9	4926.1	0	4926.1	1182.2
4	135	0	4325.3	4325.3	5847.9	0	5847.9	1522.6
5	150	0	5306.9	5306.9	6497.7	0	6497.7	1190.7
6	170	0	5836.1	5836.1	7364	0	7364	1527.9
7	180	0	6102	6102	7797.2	0	7797.2	1695.2
8	210	0	7445.1	7445.1	10359	0	10359	2914.3
9	220	0	7931.9	7931.9	10853	0	10853	2920.8
10	240	0	8935.2	8935.2	14158	0	14158	5222.6
11	250	286.39	9113.5	9399.9	13707	446.02	14153	4752.9
12	255	476.97	9110	9587	13762	630.32	14393	4805.8
13	260	692.1	9110	9802.1	13810	818.14	14628	4825.6
14	260	692.1	9110	9802.1	13810	818.14	14628	4825.6
15	255	476.97	9110	9587	13762	630.32	14393	4805.8
16	270	1122.5	9110	10233	13801	1275	15076	4843.5
17	270	1122.5	9110	10233	13801	1275	15076	4843.5
18	255	476.97	9110	9587	13762	630.32	14393	4805.8
19	240	0	8935.2	8935.2	14158	0	14158	5222.6
20	230	0	8420.7	8420.7	11346	0	11346	2925.4
21	220	0	7931.9	7931.9	10853	0	10853	2920.8
22	180	0	6102	6102	7797.2	0	7797.2	1695.2
23	150	0	5306.9	5306.9	6497.7	0	6497.7	1190.7
24	130	0	4014.9	4014.9	5336.6	0	5336.6	1321.7
Total	4940.0	5346.5	173148.8	178495.3	245806.6	6523.2	252329.8	73834.5

Table 5.17: Consumer Payment Transactions in Forward and Spot Market

Consumer payments collected at various load buses are shown below Table 5.18

Hours	SP Load (MW)	Bus 4 ($)	Bus 5 ($)	Bus 6 ($)	Total ($)
1	0	0	0	0	0
2	0	0	0	0	0
3	0	0	0	0	0
4	0	0	0	0	0
5	0	0	0	0	0
6	0	0	0	0	0
7	0	0	0	0	0
8	0	0	0	0	0
9	0	0	0	0	0
10	0	0	0	0	0
11	10	148.41	146.14	151.46	446.02
12	14.025	208.2	209.61	212.5	630.32
13	18.2	270.24	272.07	275.82	818.14
14	18.2	270.24	272.07	275.82	818.14
15	14.025	208.2	209.61	212.5	630.32
16	28.35	421.15	424	429.85	1275
17	28.35	421.15	424	429.85	1275
18	14.025	208.2	209.61	212.5	630.32
19	0	0	0	0	0
20	0	0	0	0	0
21	0	0	0	0	0
22	0	0	0	0	0
23	0	0	0	0	0
24	0	0	0	0	0

Table 5.18: Consumer Payments in Spot Price at load buses

viii Summary of Transactive Accounting for 6 Bus system

Table 5.19 depicts the summary of transactive accounting from previous sections. Rows(1), (2), (3), and (7) of the table shows the optimization results. Net profit in forward market is $ 73,387, which is the difference between forward market consumer payment and production cost. Similarly, Real time net profit is calculated is $ 73,835, which is the difference between real time market consumer payment and production cost. It is to be noted that there is a noticeable load shedding improvement in the system by including DG. Without including DG, load shedding calculated was 145 MW, whereas, by including DG load shedding came down to 0 MW.The results of this work shows that by investing in distributed generation utility makes a profit of $448 every day.

1	System Load	4,940 MW
2	Load in FM	4,795 MW
3	MW purchased from DG	124 MW
4	FM Production Cost	$172,420
5	FM Consumer Payment	$245,807
6	FM Profit [(5)-(4)]	$73,387
7	FM Load Shedding	145 MW
8	RTM Total Production Cost	$178,495
9	RTM Consumer Payment	$252,330
10	RTM Profit [(8)-(7)]	$73,835
11	RTM Load Shedding	0 MW
12	FM and RTM comparison [(10)-(6)]	$448

Table 5.19: Comparison of Forward and Spot Market per day

5.1.3 Analysis of Results

Here three metrics of comparison is performed to analyze and quantify the benefits of purchasing power from DG. They are Profit Percentage improvements, Percentage Loadshedding reduction, and Percentage Loading improvements. The calculated values of these are given below.

i Profit Percentage improvements

Net profit percentage improvement (PPI) is calculated using Equation 3.37 discussed in Chapter 3. Profit in forward market and real time market is calculated from previous sections and the net profit percentage improvement is given below.

$$\text{PPI} = \frac{NP_{SP}^{tot} - NP_{FS}^{tot}}{NP_{FS}^{tot}} \times 100\% \tag{5.1}$$

$$\text{PPI} = \frac{73,835 - 73,387}{73,387} \times 100\% \tag{5.2}$$

$$= 0.61\% \tag{5.3}$$

ii Percentage Improvement in Load shedding reduction

The net load shedding percentage reduction is calculated as given below.

$$\text{LSI} = \frac{P_L^{RTM}}{P_{LS}} \times 100\%$$

$$\text{LSI} = \frac{145}{145} \times 100\% \tag{5.4}$$

$$= 100\% \tag{5.5}$$

iii Percentage Loading improvements

Table 5.20 shows the percentage loading improvements in each transmission line of the system. The table shows the Average loading with and without DG. The average flow in all lines of the system is used in the last row to calculate the Percentage loading of the line. Table 5.21 performs the same calculations as Table 5.20 except that it performs on maximum flow of each line.

Branch Id	Without DG Avg. Percentage Loading (%)	With DG Avg. Percentage Loading (%)
1	48.57	49.02
2	70.02	70.73
3	72.64	72.79
4	23.68	24.05
5	91.01	92.09
6	91.85	91.72
7	86.33	86.71
8	80.27	79.80
9	70.92	71.01
10	17.51	16.86
11	7.10	6.70
Avg. Flow in all lines	59.99	60.13
Load Served	4795 MW	4940 MW
Percentage of total load served	97%	100%
Percentage loading	61.80%	60.13%

Table 5.20: Comparison of Forward and Spot Market Percentage Loading

Branch Id	Without DG Max Percentage Violation (%)	With DG Max Percentage Violation (%)
1	78.35	80.95
2	96.60	99.08
3	97.17	97.19
4	91.96	92.48
5	99.59	99.59
6	99.47	99.47
7	96.89	98.34
8	98.29	98.29
9	88.59	89.03
10	23.44	25.70
11	23.10	23.09
Avg. Of Max Flow in all lines	81.22	82.11
Load Served	4795 MW	4940 MW
Percentage of total load served	97%	100%
Percentage loading	83.68%	82.11%

Table 5.21: Comparison of Forward and Spot Market max.Percentage Loading

5.2 Case Study on a Fourteen Bus System

5.2.1 Input data

The following subsections describes the system specifications given as input files to run the program on a six bus system in Matlab.

i Case File

In fourteen bus sytem, unlike six bus system, there are no interface limits. However, there are synchronous condenser in fourteen bus system. The synchronous condensers were treated here as fixed shunt for the ease of calculation. Therefore, there are five parameters that needs to be given as input to MATPOWER case struct; namely baseMVA, bus, gen, branch, and gencost. They represents system base MVA, bus details, generator specifications, branch details, and generator cost function respectively. Each one of these quantities is explained in detail in the following section. The file format used to represent these parameter is included in the Appendix.

baseMVA

Matrix 'mpc.baseMVA' in the case struct is used to represent system base MVA. Base MVA is set to 100 MVA in all simulations.

Bus Specifications

There are fourteen buses in the system and are identified using the bus number. Initial P and Q load is given by second and third columns in the listing. Voltage magnitudes and angles are given by twelfth and thirteenth columns respectively. Bus matrix in case file is given by Listing 5.7

Listing 5.7: Bus data input of the fourteen bus system

```
%% bus data
%    bus_i    type     Pd   Qd   Gs   Bs   area     Vm   Va   baseKV   zone     Vmax     Vmin
mpc.bus = [
1    3    0        0        0    0        1    1.06     0        0    1    1.06     0.94;
2    2    21.7     12.7     0    0        1    1.045    -4.98    0    1    1.06     0.94;
3    1    94.2     19       0    10       1    1.01     -12.72   0    1    1.06     0.94;
4    1    47.8     -3.9     0    0        1    1.019    -10.33   0    1    1.06     0.94;
5    1    7.6      1.6      0    0        1    1.02     -8.78    0    1    1.06     0.94;
6    1    11.2     7.5      0    5.07     1    1.07     -14.22   0    1    1.06     0.94;
7    1    0        0        0    0        1    1.062    -13.37   0    1    1.06     0.94;
8    1    0        0        0    7.02     1    1.09     -13.36   0    1    1.06     0.94;
9    1    29.5     16.6     0    19       1    1.056    -14.94   0    1    1.06     0.94;
10   1    9        5.8      0    0        1    1.051    -15.1    0    1    1.06     0.94;
11   1    3.5      1.8      0    0        1    1.057    -14.79   0    1    1.06     0.94;
12   1    6.1      1.6      0    0        1    1.055    -15.07   0    1    1.06     0.94;
13   1    13.5     5.8      0    0        1    1.05     -15.16   0    1    1.06     0.94;
14   1    14.9     5        0    0        1    1.036    -16.04   0    1    1.06     0.94;
];
```

Branch Rating

The seventeen branches of the system are represented using the input matrix in case file 'mpc.branch' given by Listing 5.8. Each branch is represented using from and to bus it connects.

Listing 5.8: Branch data input of the fourteen bus system

```
%% branch data
%    fbus     tbus     r    x    b    rateA    rateB    rateC    ratio    angle
    status  angmin   angmax
mpc.branch = [
1    2    0.01938 0.05917 0.0528   140  140  140  0    0    1    -360     360;
1    5    0.05403 0.22304 0.0492   65   65   65   0    0    1    -360     360;
2    3    0.04699 0.19797 0.0438   65   65   65   0    0    1    -360     360;
2    4    0.05811 0.17632 0.034    51   51   51   0    0    1    -360     360;
2    5    0.05695 0.17388 0.0346   39   39   39   0    0    1    -360     360;
3    4    0.06701 0.17103 0.0128   23   23   23   0    0    1    -360     360;
4    5    0.01335 0.04211 0        54   54   54   0    0    1    -360     360;
4    7    0       0.20912 0        26   26   26   0.978    0    1    -360     360;
4    9    0       0.55618 0        16   16   16   0.969    0    1    -360     360;
5    6    0       0.25202 0        42   42   42   0.932    0    1    -360     360;
6    11   0.09498 0.1989  0        7    7    7    0    0    1    -360     360;
6    12   0.12291 0.25581 0        8    8    8    0    0    1    -360     360;
6    13   0.06615 0.13027 0        17   17   17   0    0    1    -360     360;
7    8    0       0.17615 0        10   10   10   0    0    1    -360     360;
7    9    0       0.11001 0        26   26   26   0    0    1    -360     360;
9    10   0.03181 0.0845  0        6    6    6    0    0    1    -360     360;
9    14   0.12711 0.27038 0        10   10   10   0    0    1    -360     360;
10   11   0.08205 0.19207 0        4    4    4    0    0    1    -360     360;
12   13   0.22092 0.19988 0        2    2    2    0    0    1    -360     360;
13   14   0.17093 0.34802 0        6    6    6    0    0    1    -360     360;
];
```

Generator data and generator cost function

The utility generators and distributed generation connected to the system and their cost is specified using input matrix in case file 'mpc.gen' and 'mpc.gencost' given by Listing 5.9 and Listing 5.10.Maximum and minimum limits of generators, Generator bus, current P and Q dispatch are input here to the system.

Listing 5.9: Generator data input (PG and DG) of the fourteen bus system

```
%% generator data
%    bus Pg   Qg   Qmax     Qmin     Vg   mBase    status   Pmax     Pmin     Pc1  Pc2  Qc1min
%        Qc1max   Qc2min   Qc2max   ramp_agc     ramp_10  ramp_30  ramp_q   apf
mpc.gen = [
1    232.4    -16.9    10       0      1.06   100  1    332.4    0    0    0    0    0    0    0    0    0
     0    0    0;
2    40       42.4     50      -40     1.045  100  1    140      0    0    0    0    0    0    0    0    0
     0    0    0;
3    0        0        500      0      1      100  1    100      1     0   0    0    0    0    0    0    0
     0    0    0;
4    0        0        500      0      1      100  1    100      1     0   0    0    0    0    0    0    0
     0    0    0;
5    0        0        500      0      1      100  1    100      1     0   0    0    0    0    0    0    0
     0    0    0;
6    0        0        500      0      1      100  1    100      1     0   0    0    0    0    0    0    0
     0    0    0;
7    0        0        500      0      1      100  1    100      1     0   0    0    0    0    0    0    0
     0    0    0;
8    0        0        500      0      1      100  1    100      1     0   0    0    0    0    0    0    0
     0    0    0;
9    0        0        500      0      1      100  1    100      1     0   0    0    0    0    0    0    0
     0    0    0;
10   0        0        500      0      1      100  1    100      1     0   0    0    0    0    0    0    0
     0    0    0;
11   0        0        500      0      1      100  1    100      1     0   0    0    0    0    0    0    0
     0    0    0;
12   0        0        500      0      1      100  1    100      1     0   0    0    0    0    0    0    0
     0    0    0;
13   0        0        500      0      1      100  1    100      1     0   0    0    0    0    0    0    0
     0    0    0;
14   0        0        500      0      1      100  1    100      1     0   0    0    0    0    0    0    0
     0    0    0;
];
```

Quadratic cost function of utiltiy generator and distributed generator are specified using input matrix in case file'mpc.gencost'. Last three columns of Listing 5.10 represents $a.\mathrm{P_g}^2, b.\mathrm{P_g}, c$ of the quadratic cost function respectively.

Listing 5.10: Generator cost input of the fourteen bus system

```
%%-----  OPF Data  -----%%
%%-- generator cost data
%   1   startup shutdown    n   x1  y1   ...  xn   yn
%   2   startup shutdown    n   c(n-1)   ...  c0
pc.gencost = [
    0   0   3   0.0430292599 20 0;
    0   0   3   0.25     20   0;
    0   0   3   0.003    43    0;
    0   0   3   0.003    43    0 ;
    0   0   3   0.003    43    0 ;
    0   0   3   0.003    43    0;
    0   0   3   0.003    43    0 ;
    0   0   3   0.003    43    0 ;
    0   0   3   0.003    43    0;
    0   0   3   0.003    43    0 ;
    0   0   3   0.003    43    0 ;
    0   0   3   0.003    43    0;
    0   0   3   0.003    43    0 ;
    0   0   3   0.003    43    0 ;]
```

ii System Load Profile

For the fourteen bus system, system load is not equally distributed among all load buses like six bus system. 24 hour day ahead load is expected for the market simulation.24 hour load profile is given input file

for as a .csv file. displays the file format used to represent system loads.

Listing 5.11: System Load of the fourteen bus system in .csv file format

```
143.8,134.3,115.1,129.5,143.9,163.07,172.7,201.4,211.03,230.2,240,244.6,249.4,249.4,
244.6,258,258,244.6,230.2,220.6,211.03,172.7,143.9,124.7
```

5.2.2 Results

Similar to subsection 5.1.2, simulation on 14 bus case file produces result in `.csv` data format.

i Generator Shift Factor

A generator shift factor for fourteen bus system is calculated based on Equation 2.25-2.26 and is presented below.

	Bus1	Bus2	Bus3	Bus4	Bus5	Bus6	Bus7	Bus8	Bus9	Bus10	Bus11	Bus12	Bus13	Bus14
Line1	0	-0.84	-0.75	-0.67	-0.61	-0.63	-0.66	-0.66	-0.65	-0.65	-0.64	-0.63	-0.63	-0.64
Line2	0	-0.16	-0.25	-0.33	-0.39	-0.37	-0.34	-0.34	-0.35	-0.35	-0.36	-0.37	-0.37	-0.36
Line3	0	0.03	-0.53	-0.15	-0.10	-0.12	-0.14	-0.14	-0.14	-0.13	-0.13	-0.12	-0.12	-0.13
Line4	0	0.06	-0.14	-0.32	-0.22	-0.25	-0.30	-0.30	-0.29	-0.28	-0.27	-0.25	-0.25	-0.27
Line5	0	0.08	-0.07	-0.20	-0.29	-0.26	-0.22	-0.22	-0.22	-0.23	-0.25	-0.26	-0.26	-0.24
Line6	0	0.03	0.47	-0.15	-0.10	-0.12	-0.14	-0.14	-0.14	-0.13	-0.13	-0.12	-0.12	-0.13
Line7	0	0.08	0.31	0.50	-0.30	-0.04	0.36	0.36	0.28	0.22	0.09	-0.01	0.01	0.16
Line8	0	0.00	0.01	0.02	-0.01	-0.21	-0.63	-0.63	-0.45	-0.40	-0.31	-0.23	-0.24	-0.36
Line9	0	0.00	0.01	0.01	-0.01	-0.12	-0.17	-0.17	-0.26	-0.24	-0.18	-0.13	-0.14	-0.21
Line10	0	0.00	-0.02	-0.03	0.02	-0.67	-0.20	-0.20	-0.29	-0.36	-0.51	-0.64	-0.62	-0.43
Line11	0	0.00	-0.01	-0.02	0.01	0.20	-0.12	-0.12	-0.18	-0.29	-0.54	0.17	0.15	-0.04
Line12	0	0.00	0.00	0.00	0.00	0.03	-0.02	-0.02	-0.03	-0.02	0.01	-0.52	-0.17	-0.09
Line13	0	0.00	-0.01	-0.01	0.01	0.10	-0.06	-0.06	-0.09	-0.06	0.02	-0.29	-0.59	-0.31
Line14	0	0	0	0	0	0	0	-1	0	0	0	0	0	0
Line15	0	0.00	0.01	0.02	-0.01	-0.21	0.37	0.37	-0.45	-0.40	-0.31	-0.23	-0.24	-0.36
Line16	0	0.00	0.01	0.02	-0.01	-0.20	0.12	0.12	0.18	-0.71	-0.46	-0.17	-0.15	0.04
Line17	0	0.00	0.01	0.01	-0.01	-0.13	0.08	0.08	0.12	0.07	-0.03	-0.19	-0.24	-0.60
Line18	0	0.00	0.01	0.02	-0.01	-0.20	0.12	0.12	0.18	0.29	-0.46	-0.17	-0.15	0.04
Line19	0	0.00	0.00	0.00	0.00	0.03	-0.02	-0.02	-0.03	-0.02	0.01	0.48	-0.17	-0.09
Line20	0	0.00	-0.01	-0.01	0.01	0.13	-0.08	-0.08	-0.12	-0.07	0.03	0.19	0.24	-0.40

Table 5.22: GSF of the fourteen bus system

ii Forward Transaction Generator Dispatch

Table 5.23 presented below shows the forward transaction generator dispatch of a fourteen bus system for various hours of the day. Column 2 gives the expected system load at various hour of the day and column 3 shows the minimum load shedding calculated.Between hours 10-19, load shedding is expected since the program do not converge with the specified load in the system.

Calculations here are used in future for spot market calculations. Table 5.24 lists the transmission line power flows and Table 5.25 lists the percentage power flows on rated capacity corresponding to the dispatch patterns shown in Table 5.23.

Hour	System Load	Load Shedding (MW)	G1 (MW)	G2 (MW)	Utility Capability / Production (MW)
1	143.89	0	124.81	23.299	148.11
2	134.3	0	116.32	21.685	138.01
3	115.11	0	99.425	18.485	117.91
4	129.5	0	112.09	20.881	132.97
5	143.89	0	124.81	23.299	148.11
6	163.07	0	141.87	26.552	168.42
7	172.67	0	150.44	28.19	178.63
8	201.44	0	176.31	33.151	209.46
9	211.04	0	184.98	34.822	219.8
10	230.22	4.6044	193.45	42.473	235.93
11	240	14.4	193.44	42.455	235.89
12	244.6	18.345	189.61	47	236.61
13	249.41	23.694	193.53	42.569	236.1
14	249.41	23.694	193.53	42.569	236.1
15	244.6	18.345	189.61	47	236.61
16	258	32.25	193.56	42.606	236.17
17	258	32.25	193.56	42.606	236.17
18	244.6	18.345	189.61	47	236.61
19	230.22	4.6044	193.45	42.473	235.93
20	220.63	0	193.62	36.58	230.2
21	211.04	0	184.98	34.822	219.8
22	172.67	0	150.44	28.19	178.63
23	143.89	0	124.81	23.299	148.11
24	124.7	0	107.86	20.08	127.94

Table 5.23: Generator Dispatch

iii Spot Market Generator Dispatch

After the calculation of forward market optimization, the program optimizes the transactions in spot market. The load in forward and spot market determined from previous section is used here. The program optimizes the purchase of power from DG to maximize utility profit. The program commits utility generators G1 and G2 first to satisfy hourly load demand; if it cannot satisfy the load demand it commits the distributed generator placed at various buses to satisfy the load demand. The Table 5.26 shows the minimum purchased power from DG at various buses to satisfy load demand. The optimization program also verifies the transmission line power flow before the final dispatch. Table 5.27 lists the transmission line power flows and Table 5.28 lists the percentage power flows on rated capacity corresponding to the dispatch patterns shown in Table 5.26.

Hour	Branch Id (MW)																			
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
1	83.57	41.24	39.98	30.73	22.82	13.21	34.17	15.48	8.92	24.49	4.13	4.31	9.83	0.00	15.48	2.84	5.17	2.16	0.90	3.16
2	77.84	38.48	37.29	28.61	21.25	12.31	31.88	14.43	8.31	22.88	3.86	4.02	9.18	0.00	14.43	2.64	4.81	2.03	0.84	2.96
3	66.44	32.99	31.93	24.39	18.12	10.50	27.30	12.33	7.11	19.65	3.34	3.45	7.88	0.00	12.33	2.23	4.10	1.77	0.73	2.56
4	74.98	37.11	35.95	27.55	20.46	11.86	30.73	13.91	8.01	22.07	3.73	3.88	8.85	0.00	13.91	2.54	4.63	1.97	0.81	2.86
5	83.57	41.24	39.98	30.73	22.82	13.21	34.17	15.48	8.92	24.49	4.13	4.31	9.83	0.00	15.48	2.84	5.17	2.16	0.90	3.16
6	95.11	46.76	45.38	34.99	25.98	15.02	38.74	17.58	10.13	27.72	4.65	4.89	11.14	0.00	17.58	3.25	5.88	2.42	1.02	3.57
7	100.92	49.52	48.10	37.14	27.58	15.92	41.03	18.63	10.74	29.34	4.91	5.17	11.79	0.00	18.63	3.46	6.24	2.55	1.07	3.77
8	118.46	57.85	56.29	43.61	32.39	18.64	47.90	21.79	12.56	34.20	5.69	6.04	13.76	0.00	21.79	4.08	7.32	2.93	1.25	4.37
9	124.35	60.63	59.03	45.78	34.00	19.54	50.19	22.85	13.16	35.81	5.95	6.33	14.41	0.00	22.85	4.29	7.68	3.06	1.31	4.57
10	132.56	64.67	63.66	48.85	36.36	20.48	52.94	24.62	14.18	38.58	6.12	6.88	15.63	0.00	24.62	4.05	8.53	2.97	1.40	4.85
11	132.09	64.66	62.46	49.02	36.53	19.10	52.96	24.39	14.05	38.43	6.17	6.83	15.05	0.00	24.39	4.47	6.63	2.89	1.12	3.50
12	132.13	64.66	62.24	49.00	36.51	18.84	52.93	24.26	13.98	38.31	6.18	6.80	14.74	0.00	24.26	4.68	5.70	2.84	0.99	2.83
13	132.20	64.66	62.06	48.97	36.49	18.62	52.89	24.07	13.87	38.18	6.13	6.79	14.47	0.00	24.07	4.68	4.85	2.72	0.86	2.18
14	132.20	64.66	62.06	48.97	36.49	18.62	52.89	24.07	13.87	38.18	6.13	6.79	14.47	0.00	24.07	4.68	4.85	2.72	0.86	2.18
15	132.13	64.66	62.24	49.00	36.51	18.84	52.93	24.26	13.98	38.31	6.18	6.80	14.74	0.00	24.26	4.68	5.70	2.84	0.99	2.83
16	132.50	64.68	61.94	48.85	36.37	18.56	52.90	23.67	13.64	37.82	6.12	6.69	13.85	0.00	23.67	3.95	3.97	2.59	0.56	1.83
17	132.50	64.68	61.94	48.85	36.37	18.56	52.90	23.67	13.64	37.82	6.12	6.69	13.85	0.00	23.67	3.95	3.97	2.59	0.56	1.83
18	132.13	64.66	62.24	49.00	36.51	18.84	52.93	24.26	13.98	38.31	6.18	6.80	14.74	0.00	24.26	4.68	5.70	2.84	0.99	2.83
19	132.56	64.67	63.66	48.85	36.36	20.48	52.94	24.62	14.18	38.58	6.12	6.88	15.63	0.00	24.62	4.05	8.53	2.97	1.40	4.85
20	130.25	63.36	61.81	47.98	35.62	20.41	52.43	23.90	13.77	37.43	6.21	6.61	15.07	0.00	23.90	4.50	8.05	3.19	1.36	4.77
21	124.35	60.63	59.03	45.78	34.00	19.54	50.19	22.85	13.16	35.81	5.95	6.33	14.41	0.00	22.85	4.29	7.68	3.06	1.31	4.57
22	100.92	49.52	48.10	37.14	27.58	15.92	41.03	18.63	10.74	29.34	4.91	5.17	11.79	0.00	18.63	3.46	6.24	2.55	1.07	3.77
23	83.57	41.24	39.98	30.73	22.82	13.21	34.17	15.48	8.92	24.49	4.13	4.31	9.83	0.00	15.48	2.84	5.17	2.16	0.90	3.16
24	72.13	35.73	34.61	26.49	19.68	11.40	29.59	13.38	7.71	21.26	3.60	3.74	8.53	0.00	13.38	2.44	4.45	1.90	0.78	2.76

Table 5.27: Branch Flow with Distributed Generator connected

Hour	Branch Id (MW)																			
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
1	83.57	41.24	39.98	30.73	22.82	13.21	34.17	15.48	8.92	24.49	4.13	4.31	9.83	0.00	15.48	2.84	5.17	2.16	0.90	3.16
2	77.84	38.48	37.29	28.61	21.25	12.31	31.88	14.43	8.31	22.88	3.86	4.02	9.18	0.00	14.43	2.64	4.81	2.03	0.84	2.96
3	66.44	32.99	31.93	24.39	18.12	10.50	27.30	12.33	7.11	19.65	3.34	3.45	7.88	0.00	12.33	2.23	4.10	1.77	0.73	2.56
4	74.98	37.11	35.95	27.55	20.46	11.86	30.73	13.91	8.01	22.07	3.73	3.88	8.85	0.00	13.91	2.54	4.63	1.97	0.81	2.86
5	83.57	41.24	39.98	30.73	22.82	13.21	34.17	15.48	8.92	24.49	4.13	4.31	9.83	0.00	15.48	2.84	5.17	2.16	0.90	3.16
6	95.11	46.76	45.38	34.99	25.98	15.02	38.74	17.58	10.13	27.72	4.65	4.89	11.14	0.00	17.58	3.25	5.88	2.42	1.02	3.57
7	100.92	49.52	48.10	37.14	27.58	15.92	41.03	18.63	10.74	29.34	4.91	5.17	11.79	0.00	18.63	3.46	6.24	2.55	1.07	3.77
8	118.46	57.85	56.29	43.61	32.39	18.64	47.90	21.79	12.56	34.20	5.69	6.04	13.76	0.00	21.79	4.08	7.32	2.93	1.25	4.37
9	124.35	60.63	59.03	45.78	34.00	19.54	50.19	22.85	13.16	35.81	5.95	6.33	14.41	0.00	22.85	4.29	7.68	3.06	1.31	4.57
10	129.45	64.00	63.50	49.55	36.96	20.76	53.22	24.49	14.11	38.24	6.32	6.76	15.40	0.00	24.49	4.64	8.26	3.22	1.39	4.86
11	129.44	64.00	63.49	49.55	36.95	20.75	53.22	24.49	14.11	38.24	6.32	6.76	15.40	0.00	24.49	4.64	8.26	3.22	1.39	4.86
12	126.17	63.45	63.84	50.01	37.45	20.70	53.02	24.58	14.16	38.32	6.31	6.78	15.44	0.00	24.58	4.67	8.30	3.21	1.39	4.86
13	129.51	64.02	63.54	49.60	36.99	20.76	53.24	24.50	14.12	38.25	6.32	6.77	15.41	0.00	24.50	4.64	8.27	3.22	1.39	4.86
14	129.51	64.02	63.54	49.60	36.99	20.76	53.24	24.50	14.12	38.25	6.32	6.77	15.41	0.00	24.50	4.64	8.27	3.22	1.39	4.86
15	126.17	63.45	63.84	50.01	37.45	20.70	53.02	24.58	14.16	38.32	6.31	6.78	15.44	0.00	24.58	4.67	8.30	3.21	1.39	4.86
16	129.53	64.03	63.56	49.62	37.01	20.77	53.24	24.51	14.12	38.26	6.32	6.77	15.41	0.00	24.51	4.64	8.27	3.22	1.39	4.86
17	129.53	64.03	63.56	49.62	37.01	20.77	53.24	24.51	14.12	38.26	6.32	6.77	15.41	0.00	24.51	4.64	8.27	3.22	1.39	4.86
18	126.17	63.45	63.84	50.01	37.45	20.70	53.02	24.58	14.16	38.32	6.31	6.78	15.44	0.00	24.58	4.67	8.30	3.21	1.39	4.86
19	129.45	64.00	63.50	49.55	36.96	20.76	53.22	24.49	14.11	38.24	6.32	6.76	15.40	0.00	24.49	4.64	8.26	3.22	1.39	4.86
20	130.25	63.36	61.81	47.98	35.62	20.41	52.43	23.90	13.77	37.43	6.21	6.61	15.07	0.00	23.90	4.50	8.05	3.19	1.36	4.77
21	124.35	60.63	59.03	45.78	34.00	19.54	50.19	22.85	13.16	35.81	5.95	6.33	14.41	0.00	22.85	4.29	7.68	3.06	1.31	4.57
22	100.92	49.52	48.10	37.14	27.58	15.92	41.03	18.63	10.74	29.34	4.91	5.17	11.79	0.00	18.63	3.46	6.24	2.55	1.07	3.77
23	83.57	41.24	39.98	30.73	22.82	13.21	34.17	15.48	8.92	24.49	4.13	4.31	9.83	0.00	15.48	2.84	5.17	2.16	0.90	3.16
24	72.13	35.73	34.61	26.49	19.68	11.40	29.59	13.38	7.71	21.26	3.60	3.74	8.53	0.00	13.38	2.44	4.45	1.90	0.78	2.76

Table 5.24: Branch Flow without connecting Distributed Generator

Hour	Branch Id (MW)																			
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
1	59.70	63.44	61.51	60.25	58.51	57.44	63.27	59.54	55.75	58.31	58.94	53.88	57.84	0.00	59.54	47.41	51.66	54.09	44.97	52.72
2	55.60	59.21	57.37	56.09	54.48	53.51	59.03	55.50	51.97	54.47	55.20	50.30	54.00	0.00	55.50	44.00	48.09	50.84	42.06	49.36
3	47.46	50.75	49.13	47.82	46.45	45.64	50.55	47.44	44.42	46.77	47.72	43.13	46.33	0.00	47.44	37.20	40.97	44.32	36.26	42.63
4	53.56	57.09	55.30	54.02	52.46	51.54	56.91	53.49	50.08	52.54	53.33	48.50	52.08	0.00	53.49	42.30	46.31	49.22	40.61	47.68
5	59.70	63.44	61.51	60.25	58.51	57.44	63.27	59.54	55.75	58.31	58.94	53.88	57.84	0.00	59.54	47.41	51.66	54.09	44.97	52.72
6	67.94	71.93	69.82	68.61	66.63	65.30	71.75	67.62	63.31	66.01	66.41	61.07	65.52	0.00	67.62	54.25	58.82	60.55	50.78	59.44
7	72.08	76.19	74.00	72.82	70.71	69.24	75.99	71.67	67.10	69.86	70.13	64.66	69.36	0.00	71.67	57.68	62.41	63.76	53.70	62.79
8	84.61	89.00	86.59	85.51	83.04	81.03	88.70	83.82	78.47	81.42	81.29	75.47	80.92	0.00	83.82	68.02	73.22	73.36	62.44	72.85
9	88.82	93.28	90.82	89.77	87.18	84.95	92.94	87.87	82.27	85.27	85.01	79.07	84.77	0.00	87.87	71.48	76.83	76.54	65.36	76.20
10	92.47	98.46	97.69	97.16	94.77	90.24	98.55	94.19	88.19	91.04	90.23	84.55	90.60	0.00	94.19	77.30	82.63	80.57	69.57	80.93
11	92.46	98.45	97.67	97.15	94.75	90.23	98.55	94.18	88.18	91.04	90.23	84.54	90.59	0.00	94.18	77.28	82.62	80.58	69.57	80.93
12	90.12	97.61	98.22	98.05	96.02	89.99	98.19	94.54	88.52	91.24	90.21	84.78	90.82	0.00	94.54	77.85	83.02	80.31	69.65	80.96
13	92.51	98.49	97.75	97.25	94.86	90.28	98.58	94.24	88.23	91.08	90.24	84.59	90.64	0.00	94.24	77.37	82.70	80.55	69.59	80.94
14	92.51	98.49	97.75	97.25	94.86	90.28	98.58	94.24	88.23	91.08	90.24	84.59	90.64	0.00	94.24	77.37	82.70	80.55	69.59	80.94
15	90.12	97.61	98.22	98.05	96.02	89.99	98.19	94.54	88.52	91.24	90.21	84.78	90.82	0.00	94.54	77.85	83.02	80.31	69.65	80.96
16	92.53	98.51	97.78	97.29	94.89	90.29	98.60	94.26	88.25	91.09	90.24	84.60	90.66	0.00	94.26	77.40	82.72	80.54	69.60	80.95
17	92.53	98.51	97.78	97.29	94.89	90.29	98.60	94.26	88.25	91.09	90.24	84.60	90.66	0.00	94.26	77.40	82.72	80.54	69.60	80.95
18	90.12	97.61	98.22	98.05	96.02	89.99	98.19	94.54	88.52	91.24	90.21	84.78	90.82	0.00	94.54	77.85	83.02	80.31	69.65	80.96
19	92.47	98.46	97.69	97.16	94.77	90.24	98.55	94.19	88.19	91.04	90.23	84.55	90.60	0.00	94.19	77.30	82.63	80.57	69.57	80.93
20	93.04	97.48	95.09	94.09	91.34	88.76	97.09	91.93	86.07	89.12	88.72	82.67	88.63	0.00	91.93	74.95	80.47	79.71	68.23	79.51
21	88.82	93.28	90.82	89.77	87.18	84.95	92.94	87.87	82.27	85.27	85.01	79.07	84.77	0.00	87.87	71.48	76.83	76.54	65.36	76.20
22	72.08	76.19	74.00	72.82	70.71	69.24	75.99	71.67	67.10	69.86	70.13	64.66	69.36	0.00	71.67	57.68	62.41	63.76	53.70	62.79
23	59.70	63.44	61.51	60.25	58.51	57.44	63.27	59.54	55.75	58.31	58.94	53.88	57.84	0.00	59.54	47.41	51.66	54.09	44.97	52.72
24	51.52	54.97	53.24	51.95	50.46	49.58	54.79	51.47	48.19	50.62	51.46	46.71	50.16	0.00	51.47	40.60	44.53	47.59	39.16	46.00

Table 5.25: Percentage of branch Flow on its rated capacity without connecting Distributed Generator

Hour	PG1 (MW)	PG2 (MW)	Bus Id (MW)												PG Total (MW)	DG Total (MW)
			3	4	5	6	7	8	9	10	11	12	13	14		
1	124.81	23.30	0	0	0	0	0	0	0	0	0	0	0	0	148.11	0
2	116.32	21.69	0	0	0	0	0	0	0	0	0	0	0	0	138.01	0
3	99.43	18.49	0	0	0	0	0	0	0	0	0	0	0	0	117.91	0
4	112.09	20.88	0	0	0	0	0	0	0	0	0	0	0	0	132.97	0
5	124.81	23.30	0	0	0	0	0	0	0	0	0	0	0	0	148.11	0
6	141.87	26.55	0	0	0	0	0	0	0	0	0	0	0	0	168.42	0
7	150.44	28.19	0	0	0	0	0	0	0	0	0	0	0	0	178.63	0
8	176.31	33.15	0	0	0	0	0	0	0	0	0	0	0	0	209.46	0
9	184.98	34.82	0	0	0	0	0	0	0	0	0	0	0	0	219.80	0
10	197.23	38.63	1.66	1.64	0	0	0	0	0	1	0	0	0	0	235.86	4.30
11	196.75	39.04	7.69	1.52	0	0	0	0	0	1	0	0	0	3.75	235.78	13.96
12	196.79	39.13	9.82	1.96	0	0	0	0	0	1	0	0	0	5.60	235.92	18.38
13	196.86	39.22	11.95	2.40	0	0	0	0	0	1.28	0	0	0	7.35	236.09	22.99
14	196.86	39.22	11.95	2.40	0	0	0	0	0	1.28	0	0	0	7.35	236.09	22.99
15	196.79	39.13	9.82	1.96	0	0	0	0	0	1	0	0	0	5.60	235.92	18.38
16	197.18	39.31	15.25	3.38	0	0	0	0	0	2.44	0	0	1	9.07	236.49	31.14
17	197.18	39.31	15.25	3.38	0	0	0	0	0	2.44	0	0	1	9.07	236.49	31.14
18	196.79	39.13	9.82	1.96	0	0	0	0	0	1	0	0	0	5.60	235.92	18.38
19	197.23	38.63	1.66	1.64	0	0	0	0	0	1	0	0	0	0	235.86	4.30
20	193.62	36.58	0	0	0	0	0	0	0	0	0	0	0	0	230.20	0
21	184.98	34.82	0	0	0	0	0	0	0	0	0	0	0	0	219.80	0
22	150.44	28.19	0	0	0	0	0	0	0	0	0	0	0	0	178.63	0
23	124.81	23.30	0	0	0	0	0	0	0	0	0	0	0	0	148.11	0
24	107.86	20.08	0	0	0	0	0	0	0	0	0	0	0	0	127.94	0
Total	3962.40	764.11	94.89	22.21	0.00	0.00	0.00	0.00	0.00	13.43	0.00	0.00	2.00	53.42	4726.50	185.96

Table 5.26: Minimum power purchase from DG to avoid Load shedding

Hour	Branch Id (MW)																			
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
1	59.70	63.44	61.51	60.25	58.51	57.44	63.27	59.54	55.75	58.31	58.94	53.88	57.84	0.00	59.54	47.41	51.66	54.09	44.97	52.72
2	55.60	59.21	57.37	56.09	54.48	53.51	59.03	55.50	51.97	54.47	55.20	50.30	54.00	0.00	55.50	44.00	48.09	50.84	42.06	49.36
3	47.46	50.75	49.13	47.82	46.45	45.64	50.55	47.44	44.42	46.77	47.72	43.13	46.33	0.00	47.44	37.20	40.97	44.32	36.26	42.63
4	53.56	57.09	55.30	54.02	52.46	51.54	56.91	53.49	50.08	52.54	53.33	48.50	52.08	0.00	53.49	42.30	46.31	49.22	40.61	47.68
5	59.70	63.44	61.51	60.25	58.51	57.44	63.27	59.54	55.75	58.31	58.94	53.88	57.84	0.00	59.54	47.41	51.66	54.09	44.97	52.72
6	67.94	71.93	69.82	68.61	66.63	65.30	71.75	67.62	63.31	66.01	66.41	61.07	65.52	0.00	67.62	54.25	58.82	60.55	50.78	59.44
7	72.08	76.19	74.00	72.82	70.71	69.24	75.99	71.67	67.10	69.86	70.13	64.66	69.36	0.00	71.67	57.68	62.41	63.76	53.70	62.79
8	84.61	89.00	86.59	85.51	83.04	81.03	88.70	83.82	78.47	81.42	81.29	75.47	80.92	0.00	83.82	68.02	73.22	73.36	62.44	72.85
9	88.82	93.28	90.82	89.77	87.18	84.95	92.94	87.87	82.27	85.27	85.01	79.07	84.77	0.00	87.87	71.48	76.83	76.54	65.36	76.20
10	94.69	99.49	97.93	95.79	93.24	89.02	98.03	94.68	88.65	91.86	87.37	85.96	91.95	0.00	94.68	67.51	85.28	74.15	69.84	80.91
11	94.35	99.48	96.09	96.12	93.66	83.02	98.06	93.80	87.82	91.49	88.19	85.33	88.52	0.00	93.80	74.46	66.35	72.25	55.85	58.28
12	94.38	99.48	95.75	96.08	93.62	81.90	98.01	93.31	87.36	91.21	88.35	85.05	86.71	0.00	93.31	77.96	57.00	70.98	49.32	47.08
13	94.43	99.48	95.47	96.02	93.56	80.96	97.95	92.59	86.69	90.89	87.60	84.86	85.11	0.00	92.59	78.04	48.54	68.05	42.93	36.34
14	94.43	99.48	95.47	96.02	93.56	80.96	97.95	92.59	86.69	90.89	87.60	84.86	85.11	0.00	92.59	78.04	48.54	68.05	42.93	36.34
15	94.38	99.48	95.75	96.08	93.62	81.90	98.01	93.31	87.36	91.21	88.35	85.05	86.71	0.00	93.31	77.96	57.00	70.98	49.32	47.08
16	94.64	99.50	95.30	95.79	93.26	80.68	97.97	91.03	85.22	90.05	87.45	83.63	81.47	0.00	91.03	65.86	39.65	64.84	27.99	30.54
17	94.64	99.50	95.30	95.79	93.26	80.68	97.97	91.03	85.22	90.05	87.45	83.63	81.47	0.00	91.03	65.86	39.65	64.84	27.99	30.54
18	94.38	99.48	95.75	96.08	93.62	81.90	98.01	93.31	87.36	91.21	88.35	85.05	86.71	0.00	93.31	77.96	57.00	70.98	49.32	47.08
19	94.69	99.49	97.93	95.79	93.24	89.02	98.03	94.68	88.65	91.86	87.37	85.96	91.95	0.00	94.68	67.51	85.28	74.15	69.84	80.91
20	93.04	97.48	95.09	94.09	91.34	88.76	97.09	91.93	86.07	89.12	88.72	82.67	88.63	0.00	91.93	74.95	80.47	79.71	68.23	79.51
21	88.82	93.28	90.82	89.77	87.18	84.95	92.94	87.87	82.27	85.27	85.01	79.07	84.77	0.00	87.87	71.48	76.83	76.54	65.36	76.20
22	72.08	76.19	74.00	72.82	70.71	69.24	75.99	71.67	67.10	69.86	70.13	64.66	69.36	0.00	71.67	57.68	62.41	63.76	53.70	62.79
23	59.70	63.44	61.51	60.25	58.51	57.44	63.27	59.54	55.75	58.31	58.94	53.88	57.84	0.00	59.54	47.41	51.66	54.09	44.97	52.72
24	51.52	54.97	53.24	51.95	50.46	49.58	54.79	51.47	48.19	50.62	51.46	46.71	50.16	0.00	51.47	40.60	44.53	47.59	39.16	46.00

Table 5.28: Percentage of branch Flow on its rated capacity with Distributed Generator connected

iv Binding Constraints

After the calculation of generator dispatch in forward and spot market, binding constraints in the trans- mission lines are determined. Forward subscription price and spot price are determined based on LMP at various buses which is calculated based on binding constraints in transmission lines. Table 5.30 and Table 5.32 show the binding constraints for forward and spot market at various hours of the day. Since there are no interface limits for a fourteen bus system, the last column of Table 5.30 and Table 5.32 remain zero.

Hour	Branch Id	Power Flow (MW)	Branch Ratings (MW)	Percentage Flow on Rated Capacity(%)	Line (0) Interface(1)
10	2	63.999	65	98.46	0
10	7	53.218	54	98.551	0
11	2	63.995	65	98.454	0
11	7	53.215	54	98.546	0
12	3	63.842	65	98.219	0
12	4	50.007	51	98.053	0
12	7	53.021	54	98.187	0
13	2	64.021	65	98.493	0
13	7	53.235	54	98.583	0
14	2	64.021	65	98.493	0
14	7	53.235	54	98.583	0
15	3	63.842	65	98.219	0
15	4	50.007	51	98.053	0
15	7	53.021	54	98.187	0
16	2	64.029	65	98.506	0
16	7	53.241	54	98.595	0
17	2	64.029	65	98.506	0
17	7	53.241	54	98.595	0
18	3	63.842	65	98.219	0
18	4	50.007	51	98.053	0
18	7	53.021	54	98.187	0
19	2	63.999	65	98.46	0
19	7	53.218	54	98.551	0

Table 5.30: Binding Constraints without Distributed Generation

Hour	Branch Id	Power Flow (MW)	Branch Ratings (MW)	Percentage Violation (%)	Line (0) Interface(1)
10	2	64.665	65	99.485	0
10	3	63.655	65	97.93	0
10	7	52.937	54	98.031	0
11	2	64.659	65	99.476	0
11	7	52.955	54	98.064	0
12	2	64.659	65	99.475	0
12	7	52.926	54	98.011	0
13	2	64.66	65	99.477	0
13	7	52.893	54	97.949	0
14	2	64.66	65	99.477	0
14	7	52.893	54	97.949	0
15	2	64.659	65	99.475	0
15	7	52.926	54	98.011	0
16	2	64.675	65	99.499	0
16	7	52.901	54	97.966	0
17	2	64.675	65	99.499	0
17	7	52.901	54	97.966	0
18	2	64.659	65	99.475	0
18	7	52.926	54	98.011	0
19	2	64.665	65	99.485	0
19	3	63.655	65	97.93	0
19	7	52.937	54	98.031	0
20	2	63.362	65	97.48	0
20	7	52.427	54	97.086	0

Table 5.32: Binding Constraints with Distributed Generation Included

v Forward market Transactive Accounting

Table 5.33- 5.34 shows the transactive accounting for forward market. Table 5.33 shows the total system load along with the load shedding expected in Forward market. Next the cost of energy at each bus, which is the LMP of the system is shown for entire 24 hour load. LMP at every bus is different since the binding constraints of different lines and power loss of transmission lines are different. The energy price from Table 5.33 is used in Table 5.34 to calculate the consumer payments at various bus. Utility dispatch and total minimum production cost are the result of optimization performed in the previous section. Net Profit of each transaction is calculated as the difference of total consumer payment and production cost.

vi Energy Cost

Table 5.35 presents the total energy cost at various bus in forward and spot market. Calculation of forward subscription cost was shown in previous sections. Here the focus is to calculate the spot price at various buses. Spot price is calculated using the incremental flow equation described in Chapter 3, considering utility and distributed generation, unlike forward subscription which considers only utility generation. By solving the linear equation for incremental flow equation nodal prices are determined.

vii Transactive accounting in Spot market

Table 5.36 summarizes the total dispatch in forward and spot market calculated using the optimization proposed in this work. PG and DG dispatch is shown below along with load in forward and spot market which is later used to calculate consumer payment in real time.

Hour	System Load (MW)	load Shedding (MW)	Load in FT (MW)	LMP ($ per MW)													
				Bus 1	Bus 2	Bus 3	Bus 4	Bus 5	Bus 6	Bus 7	Bus 8	Bus 9	Bus 10	Bus 11	Bus 12	Bus 13	Bus 14
1	143.89	0	143.89	25.825	26.231	26.988	26.568	26.481	26.818	26.648	26.648	26.781	27.319	27.801	29.194	27.853	28.595
2	134.3	0	134.3	25.421	25.821	26.566	26.153	26.068	26.399	26.232	26.232	26.362	26.892	27.366	28.738	27.418	28.148
3	115.11	0	115.11	24.621	25.009	25.73	25.33	25.248	25.568	25.407	25.407	25.533	26.046	26.505	27.834	26.556	27.262
4	129.5	0	129.5	25.22	25.617	26.356	25.947	25.862	26.19	26.024	26.024	26.154	26.68	27.15	28.511	27.201	27.925
5	143.89	0	143.89	25.825	26.231	26.988	26.568	26.481	26.818	26.648	26.648	26.781	27.319	27.801	29.194	27.853	28.595
6	163.07	0	163.07	26.638	27.057	27.837	27.405	27.316	27.663	27.487	27.487	27.624	28.179	28.676	30.114	28.731	29.495
7	172.67	0	172.67	27.047	27.473	28.265	27.826	27.735	28.088	27.91	27.91	28.049	28.613	29.117	30.577	29.172	29.949
8	201.44	0	201.44	28.288	28.733	29.562	29.102	29.007	29.376	29.19	29.19	29.335	29.925	30.452	31.979	30.51	31.322
9	211.04	0	211.04	28.706	29.157	29.998	29.532	29.436	29.81	29.621	29.621	29.768	30.367	30.902	32.451	30.961	31.784
10	230.22	4.6044	225.62	36.691	42.139	49.036	53.601	43.574	47.193	51.857	51.857	51.107	51.393	50.616	51.706	49.58	52.938
11	240	14.4	225.6	36.69	42.13	49.018	53.577	43.563	47.178	51.835	51.835	51.087	51.373	50.598	51.689	49.564	52.919
12	244.6	18.345	226.25	36.361	44.438	39.253	50.849	14.126	24.371	43.061	43.061	39.225	37.099	31.363	27.697	27.309	35.547
13	249.41	23.694	225.71	36.698	42.188	49.13	53.731	43.631	47.275	51.974	51.974	51.218	51.501	50.714	51.798	49.67	53.045
14	249.41	23.694	225.71	36.698	42.188	49.13	53.731	43.631	47.275	51.974	51.974	51.218	51.501	50.714	51.798	49.67	53.045
15	244.6	18.345	226.26	36.361	44.438	39.253	50.849	14.126	24.371	43.061	43.061	39.225	37.099	31.363	27.697	27.309	35.547
16	258	32.25	225.75	36.701	42.207	49.166	53.78	43.653	47.306	52.019	52.019	51.26	51.542	50.751	51.833	49.704	53.086
17	258	32.25	225.75	36.701	42.207	49.166	53.78	43.653	47.306	52.019	52.019	51.26	51.542	50.751	51.833	49.704	53.086
18	244.6	18.345	226.26	36.361	44.438	39.253	50.849	14.126	24.371	43.061	43.061	39.225	37.099	31.363	27.697	27.309	35.547
19	230.22	4.6044	225.62	36.691	42.139	49.036	53.601	43.574	47.193	51.857	51.857	51.107	51.393	50.616	51.706	49.58	52.938
20	220.63	0	220.63	29.145	29.604	30.457	29.984	29.886	30.266	30.074	30.074	30.224	30.832	31.375	32.948	31.435	32.271
21	211.04	0	211.04	28.706	29.157	29.998	29.532	29.436	29.81	29.621	29.621	29.768	30.367	30.902	32.451	30.961	31.784
22	172.67	0	172.67	27.047	27.473	28.265	27.826	27.735	28.088	27.91	27.91	28.049	28.613	29.117	30.577	29.172	29.949
23	143.89	0	143.89	25.825	26.231	26.988	26.568	26.481	26.818	26.648	26.648	26.781	27.319	27.801	29.194	27.853	28.595
24	124.7	0	124.7	25.02	25.414	26.147	25.74	25.656	25.982	25.818	25.818	25.946	26.468	26.934	28.284	26.985	27.704

Table 5.33: LMP at various buses without DG in the system (Forward Subscription Cost)

Hour	System Load (MW)	Load Shedding (MW)	Utility Dispatch (MW)	Min. Prod. cost ($)	CP1 at Bus 2 ($)	CP2 at Bus 3 ($)	CP3 at Bus 4 ($)	CP4 at Bus 5 ($)	CP5 at Bus 6 ($)	CP6 at Bus 9 ($)	CP7 at Bus 10 ($)	CP8 at Bus 11 ($)	CP9 at Bus 12 ($)	CP10 at Bus 13 ($)	CP11 at Bus 14 ($)	Total CP ($)	Net Profit ($)
1	143.89	0	148.11	3768.2	316.23	1412.3	705.54	111.81	166.87	438.9	136.59	54.057	98.936	208.9	236.7	3886.9	118.71
2	134.3	0	138.01	3459.9	290.54	1297.6	648.21	102.73	153.31	403.24	125.5	49.665	90.897	191.93	217.47	3571.1	111.17
3	115.11	0	117.91	2869	241.2	1077.2	538.13	85.281	127.27	334.76	104.18	41.231	75.461	159.33	180.54	2964.6	95.625
4	129.5	0	132.97	3309	277.94	1241.4	620.12	98.275	146.67	385.77	120.06	47.513	86.958	183.61	208.04	3416.3	107.34
5	143.89	0	148.11	3768.2	316.23	1412.3	705.54	111.81	166.87	438.9	136.59	54.057	98.936	208.9	236.7	3886.9	118.71
6	163.07	0	168.42	4410.7	369.68	1651.1	824.79	130.71	195.07	513.09	159.68	63.194	115.66	244.21	276.71	4543.9	133.17
7	172.67	0	178.63	4745.1	397.44	1775.1	886.73	140.53	209.72	551.62	171.68	67.94	124.34	262.55	297.49	4885.1	140.03
8	201.44	0	209.46	5801.5	484.95	2165.9	1082	171.47	255.9	673.07	209.47	82.898	151.72	320.35	362.99	5960.7	159.2
9	211.04	0	219.8	6171.5	515.54	2302.5	1150.2	182.28	272.04	715.54	222.69	88.128	161.29	340.57	385.89	6336.7	165.17
10	230.22	4.6044	235.93	6779.8	796.56	4023.8	2231.9	288.48	460.44	1313.3	402.92	154.32	274.76	583.06	687.12	11217	4436.9
11	240	14.4	235.89	6778.6	796.32	4022.1	2230.7	288.38	460.25	1312.7	402.73	154.26	274.64	582.82	686.81	11212	4433.2
12	244.6	18.345	236.61	6831.5	842.4	3230.2	2123.3	93.782	238.44	1010.9	291.68	95.893	147.59	322.06	462.69	8858.8	2027.3
13	249.41	23.694	236.1	6786.7	797.82	4033.3	2238.3	288.98	461.43	1316.8	403.94	154.69	275.36	584.37	688.8	11244	4456.9
14	249.41	23.694	236.1	6786.7	797.82	4033.3	2238.3	288.98	461.43	1316.8	403.94	154.69	275.36	584.37	688.8	11244	4456.9
15	244.6	18.345	236.61	6831.5	842.4	3230.2	2123.3	93.782	238.44	1010.9	291.68	95.893	147.59	322.06	462.69	8858.8	2027.3
16	258	32.25	236.17	6789.4	798.31	4036.8	2240.7	289.17	461.81	1318.1	404.33	154.83	275.59	584.86	689.43	11254	4464.5
17	258	32.25	236.17	6789.4	798.31	4036.8	2240.7	289.17	461.81	1318.1	404.33	154.83	275.59	584.86	689.43	11254	4464.5
18	244.6	18.345	236.61	6831.5	842.4	3230.2	2123.3	93.782	238.44	1010.9	291.68	95.893	147.59	322.06	462.69	8858.8	2027.3
19	230.22	4.6044	235.93	6779.8	796.56	4023.8	2231.9	288.48	460.44	1313.3	402.92	154.32	274.76	583.06	687.12	11217	4436.9
20	220.63	0	230.2	6551.5	547.23	2444	1220.9	193.49	288.76	759.51	236.37	93.545	171.21	361.5	409.6	6726.2	174.71
21	211.04	0	219.8	6171.5	515.54	2302.5	1150.2	182.28	272.04	715.54	222.69	88.128	161.29	340.57	385.89	6336.7	165.17
22	172.67	0	178.63	4745.1	397.44	1775.1	886.73	140.53	209.72	551.62	171.68	67.94	124.34	262.55	297.49	4885.1	140.03
23	143.89	0	148.11	3768.2	316.23	1412.3	705.54	111.81	166.87	438.9	136.59	54.057	98.936	208.9	236.7	3886.9	118.71
24	124.7	0	127.94	3160.2	265.52	1185.9	592.41	93.883	140.11	368.53	114.69	45.389	83.072	175.4	198.75	3263.7	103.46
Total	4736.9	190.5	4728.2	130684.5	13360.6	61355.6	33739.4	4159.9	6714.2	19530.6	5968.6	2267.3	4011.9	8522.9	10136.5	169767.5	39083.0

Table 5.34: Consumer Payment in Forward Subscription

	FS prices ($ per MW)														SP prices ($ per MW)													
Hour	Bus 1	Bus 2	Bus 3	Bus 4	Bus 5	Bus 6	Bus 7	Bus 8	Bus 9	Bus 10	Bus 11	Bus 12	Bus 13	Bus 14	Bus 1	Bus 2	Bus 3	Bus 4	Bus 5	Bus 6	Bus 7	Bus 8	Bus 9	Bus 10	Bus 11	Bus 12	Bus 13	Bus 14
1	25.8	26.2	27.0	26.6	26.5	26.8	26.6	26.6	26.8	27.3	27.8	29.2	27.9	28.6	25.8	26.2	27.0	26.6	26.5	26.8	26.6	26.6	26.8	27.3	27.8	29.2	27.9	28.6
2	25.4	25.8	26.6	26.2	26.1	26.4	26.2	26.2	26.4	26.9	27.4	28.7	27.4	28.1	25.4	25.8	26.6	26.2	26.1	26.4	26.2	26.2	26.4	26.9	27.4	28.7	27.4	28.1
3	24.6	25.0	25.7	25.3	25.2	25.6	25.4	25.4	25.5	26.0	26.5	27.8	26.6	27.3	24.6	25.0	25.7	25.3	25.2	25.6	25.4	25.4	25.5	26.0	26.5	27.8	26.6	27.3
4	25.2	25.6	26.4	25.9	25.9	26.2	26.0	26.0	26.2	26.7	27.2	28.5	27.2	27.9	25.2	25.6	26.4	25.9	25.9	26.2	26.0	26.0	26.2	26.7	27.2	28.5	27.2	27.9
5	25.8	26.2	27.0	26.6	26.5	26.8	26.6	26.6	26.8	27.3	27.8	29.2	27.9	28.6	25.8	26.2	27.0	26.6	26.5	26.8	26.6	26.6	26.8	27.3	27.8	29.2	27.9	28.6
6	26.6	27.1	27.8	27.4	27.3	27.7	27.5	27.5	27.6	28.2	28.7	30.1	28.7	29.5	26.6	27.1	27.8	27.4	27.3	27.7	27.5	27.5	27.6	28.2	28.7	30.1	28.7	29.5
7	27.0	27.5	28.3	27.8	27.7	28.1	27.9	27.9	28.0	28.6	29.1	30.6	29.2	29.9	27.0	27.5	28.3	27.8	27.7	28.1	27.9	27.9	28.0	28.6	29.1	30.6	29.2	29.9
8	28.3	28.7	29.6	29.1	29.0	29.4	29.2	29.2	29.3	29.9	30.5	32.0	30.5	31.3	28.3	28.7	29.6	29.1	29.0	29.4	29.2	29.2	29.3	29.9	30.5	32.0	30.5	31.3
9	28.7	29.2	30.0	29.5	29.4	29.8	29.6	29.6	29.8	30.4	30.9	32.5	31.0	31.8	28.7	29.2	30.0	29.5	29.4	29.8	29.6	29.6	29.8	30.4	30.9	32.5	31.0	31.8
10	36.7	42.1	49.0	53.6	43.6	47.2	51.9	51.9	51.1	51.4	50.6	51.7	49.6	52.9	37.0	40.0	45.0	44.3	44.1	44.7	44.4	44.4	44.6	45.5	46.3	48.6	46.4	47.6
11	36.7	42.1	49.0	53.6	43.6	47.2	51.8	51.8	51.1	51.4	50.6	51.7	49.6	52.9	37.0	40.3	43.3	44.3	44.1	44.7	44.4	44.4	44.6	45.5	46.3	48.6	46.4	47.6
12	36.4	44.4	39.3	50.8	14.1	24.4	43.1	43.1	39.2	37.1	31.4	27.7	27.3	35.5	37.0	40.3	43.3	44.3	44.1	44.7	44.4	44.4	44.6	45.5	46.3	48.6	46.4	47.6
13	36.7	42.2	49.1	53.7	43.6	47.3	52.0	52.0	51.2	51.5	50.7	51.8	49.7	53.0	37.0	40.3	43.4	44.3	44.1	44.7	44.4	44.4	44.6	45.5	46.3	48.6	46.4	47.6
14	36.7	42.2	49.1	53.7	43.6	47.3	52.0	52.0	51.2	51.5	50.7	51.8	49.7	53.0	37.0	40.3	43.4	44.3	44.1	44.7	44.4	44.4	44.6	45.5	46.3	48.6	46.4	47.6
15	36.4	44.4	39.3	50.8	14.1	24.4	43.1	43.1	39.2	37.1	31.4	27.7	27.3	35.5	37.0	40.3	43.3	44.3	44.1	44.7	44.4	44.4	44.6	45.5	46.3	48.6	46.4	47.6
16	36.7	42.2	49.2	53.8	43.7	47.3	52.0	52.0	51.3	51.5	50.8	51.8	49.7	53.1	37.0	40.4	43.4	44.3	44.1	44.7	44.4	44.4	44.6	45.5	46.3	48.6	46.4	47.6
17	36.7	42.2	49.2	53.8	43.7	47.3	52.0	52.0	51.3	51.5	50.8	51.8	49.7	53.1	37.0	40.4	43.4	44.3	44.1	44.7	44.4	44.4	44.6	45.5	46.3	48.6	46.4	47.6
18	36.4	44.4	39.3	50.8	14.1	24.4	43.1	43.1	39.2	37.1	31.4	27.7	27.3	35.5	37.0	40.3	43.3	44.3	44.1	44.7	44.4	44.4	44.6	45.5	46.3	48.6	46.4	47.6
19	36.7	42.1	49.0	53.6	43.6	47.2	51.9	51.9	51.1	51.4	50.6	51.7	49.6	52.9	37.0	40.0	45.0	44.3	44.1	44.7	44.4	44.4	44.6	45.5	46.3	48.6	46.4	47.6
20	29.1	29.6	30.5	30.0	29.9	30.3	30.1	30.1	30.2	30.8	31.4	32.9	31.4	32.3	36.7	40.2	43.3	44.2	44.1	44.7	44.4	44.4	44.6	45.5	46.3	48.6	46.4	47.6
21	28.7	29.2	30.0	29.5	29.4	29.8	29.6	29.6	29.8	30.4	30.9	32.5	31.0	31.8	28.7	29.2	30.0	29.5	29.4	29.8	29.6	29.6	29.8	30.4	30.9	32.5	31.0	31.8
22	27.0	27.5	28.3	27.8	27.7	28.1	27.9	27.9	28.0	28.6	29.1	30.6	29.2	29.9	27.0	27.5	28.3	27.8	27.7	28.1	27.9	27.9	28.0	28.6	29.1	30.6	29.2	29.9
23	25.8	26.2	27.0	26.6	26.5	26.8	26.6	26.6	26.8	27.3	27.8	29.2	27.9	28.6	25.8	26.2	27.0	26.6	26.5	26.8	26.6	26.6	26.8	27.3	27.8	29.2	27.9	28.6
24	25.0	25.4	26.1	25.7	25.7	26.0	25.8	25.8	25.9	26.5	26.9	28.3	27.0	27.7	25.0	25.4	26.1	25.7	25.7	26.0	25.8	25.8	25.9	26.5	26.9	28.3	27.0	27.7

Table 5.35: Forward Subscription and Spot Price Table

Hour	System Load (MW)	PG Dispatch (MW)	DG Dispatch (MW)	Load in FS (MW)	Load in SP (MW)
1	143.89	148.11	0	143.89	0
2	134.3	138.01	0	134.3	0
3	115.11	117.91	0	115.11	0
4	129.5	132.97	0	129.5	0
5	143.89	148.11	0	143.89	0
6	163.07	168.42	0	163.07	0
7	172.67	178.63	0	172.67	0
8	201.44	209.46	0	201.44	0
9	211.04	219.8	0	211.04	0
10	230.22	235.86	4.2974	225.62	4.6044
11	240	235.78	13.964	225.6	14.4
12	244.6	235.92	18.383	226.25	18.345
13	249.41	236.09	22.986	225.71	23.694
14	249.41	236.09	22.986	225.71	23.694
15	244.6	235.92	18.383	226.26	18.345
16	258	236.49	31.138	225.75	32.25
17	258	236.49	31.138	225.75	32.25
18	244.6	235.92	18.383	226.26	18.345
19	230.22	235.86	4.2974	225.62	4.6044
20	220.63	230.2	0	220.63	0
21	211.04	219.8	0	211.04	0
22	172.67	178.63	0	172.67	0
23	143.89	148.11	0	143.89	0
24	124.7	127.94	0	124.7	0
Total	4736.89	4726.50	185.96	4546.36	190.53

Table 5.36: Generator Dispatch in Forward and Spot Market

Table 5.36 is used to calculate the consumer payment in spot market (Table 5.37). First the total cost to utility is calculated as the sum of production cost of utility generator and distributed generator. Next, total consumer payment is calculated as the sum of consumer payments in forward and spot market. Consumer payment in spot market is calculated based on the load in spot market calculated above. Net profit in real time is calculated as the difference of total consumer payment including the payment in forward subscription and spot price, and the total production cost of power.Consumer payments collected from various buses and the total spot market load at different hours of the day are presented in Table 5.38.

Hour	System Load (MW)	DG Power Cost ($)	Pg Power Cost ($)	Total Cost to Utility ($)	CP in FS ($)	CP in SP ($)	Total CP ($)	Net Profit ($)
1	143.89	0	3768.2	3768.2	3886.9	0	3886.9	118.71
2	134.3	0	3459.9	3459.9	3571.1	0	3571.1	111.17
3	115.11	0	2869	2869	2964.6	0	2964.6	95.625
4	129.5	0	3309	3309	3416.3	0	3416.3	107.34
5	143.89	0	3768.2	3768.2	3886.9	0	3886.9	118.71
6	163.07	0	4410.7	4410.7	4543.9	0	4543.9	133.17
7	172.67	0	4745.1	4745.1	4885.1	0	4885.1	140.03
8	201.44	0	5801.5	5801.5	5960.7	0	5960.7	159.2
9	211.04	0	6171.5	6171.5	6336.7	0	6336.7	165.17
10	230.22	184.81	6763.9	6948.7	11217	205.75	11422	4473.7
11	240	600.7	6762.3	7363	11212	635.41	11847	4484.1
12	244.6	790.89	6767.6	7558.5	8858.8	809.52	9668.4	2109.9
13	249.41	988.99	6774	7763	11244	1045.6	12289	4526.3
14	249.41	988.99	6774	7763	11244	1045.6	12289	4526.3
15	244.6	790.89	6767.6	7558.5	8858.8	809.52	9668.4	2109.9
16	258	1339.9	6789.1	8129	11254	1423.5	12677	4548.3
17	258	1339.9	6789.1	8129	11254	1423.5	12677	4548.3
18	244.6	790.89	6767.6	7558.5	8858.8	809.52	9668.4	2109.9
19	230.22	184.81	6763.9	6948.7	11217	205.75	11422	4473.7
20	220.63	0	6551.5	6551.5	6726.2	0	6726.2	174.71
21	211.04	0	6171.5	6171.5	6336.7	0	6336.7	165.17
22	172.67	0	4745.1	4745.1	4885.1	0	4885.1	140.03
23	143.89	0	3768.2	3768.2	3886.9	0	3886.9	118.71
24	124.7	0	3160.2	3160.2	3263.7	0	3263.7	103.46
Total	4736.9	8000.8	130419	138419	169768	8413	178181	39762

Table 5.37: Consumer Payment Transactions in Forward and Spot Market

Hours	SP Load (MW)	Bus 2 ($)	Bus 3 ($)	Bus 4 ($)	Bus 5 ($)	Bus 6 ($)	Bus 9 ($)	Bus 10 ($)	Bus 11 ($)	Bus 12 ($)	Bus 13 ($)	Bus 14 ($)	Total ($)
1	0	0	0	0	0	0	0	0	0	0	0	0	0
2	0	0	0	0	0	0	0	0	0	0	0	0	0
3	0	0	0	0	0	0	0	0	0	0	0	0	0
4	0	0	0	0	0	0	0	0	0	0	0	0	0
5	0	0	0	0	0	0	0	0	0	0	0	0	0
6	0	0	0	0	0	0	0	0	0	0	0	0	0
7	0	0	0	0	0	0	0	0	0	0	0	0	0
8	0	0	0	0	0	0	0	0	0	0	0	0	0
9	0	0	0	0	0	0	0	0	0	0	0	0	0
10	4.6	15.4	75.3	37.6	6.0	8.9	23.4	7.3	2.9	5.3	11.1	12.6	205.8
11	14.4	48.7	227.0	117.6	18.6	27.8	73.2	22.8	9.0	16.5	34.8	39.4	635.4
12	18.3	62.0	289.2	149.8	23.7	35.4	93.2	29.0	11.5	21.0	44.4	50.3	809.5
13	23.7	80.1	373.6	193.5	30.7	45.8	120.4	37.5	14.8	27.1	57.3	64.9	1045.6
14	23.7	80.1	373.6	193.5	30.7	45.8	120.4	37.5	14.8	27.1	57.3	64.9	1045.6
15	18.3	62.0	289.2	149.8	23.7	35.4	93.2	29.0	11.5	21.0	44.4	50.3	809.5
16	32.3	109.1	508.6	263.5	41.7	62.3	163.9	51.0	20.2	36.9	78.0	88.4	1423.5
17	32.3	109.1	508.6	263.5	41.7	62.3	163.9	51.0	20.2	36.9	78.0	88.4	1423.5
18	18.3	62.0	289.2	149.8	23.7	35.4	93.2	29.0	11.5	21.0	44.4	50.3	809.5
19	4.6	15.4	75.3	37.6	6.0	8.9	23.4	7.3	2.9	5.3	11.1	12.6	205.8
20	0	0	0	0	0	0	0	0	0	0	0	0	0
21	0	0	0	0	0	0	0	0	0	0	0	0	0
22	0	0	0	0	0	0	0	0	0	0	0	0	0
23	0	0	0	0	0	0	0	0	0	0	0	0	0
24	0	0	0	0	0	0	0	0	0	0	0	0	0

Table 5.38: Consumer Payments in Spot Price at load buses

viii Summary of Transactive Accounting for 14 Bus system

Table 5.39 depicts the summary of transactive accounting from previous sections.Rows (1), (2), (3), and (7) of the table shows the optimization results. Row (6) shows the net profit in forward market as $39,083, which is the difference between forward market consumer payment and production cost . Real time market net profit (Row (10)) is calculated as $39,762, which is the difference between real time market consumer payment and production cost (Row (8)-(7)). By purchasing power from DG the total load shedding came down to 0 MW from 190.5 MW. The table concludes that by investing in distributed generation utility makes a profit of $679 every day.

1	System Load	4737MW
2	Load in FM	4546 MW
3	MW purchased from DG	186 MW
4	FM Production Cost	$130,684
5	FM Consumer Payment	$169,767
6	FM Profit [(5)-(4)]	$39,083
7	FM Load Shedding	190.5MW
8	RTM Total Production Cost	$138,419
9	RTM Consumer Payment	$178,181
10	RTM Profit [(8)-(7)]	$39,762
11	RTM Load Shedding	0 MW
12	FM and RTM comparison [(10)-(6)]	$679

Table 5.39: Comparison of Forward and Spot Market per day

5.2.3 Analysis of Results

Here three metrics of comparison is performed to analyze and quantify the benefits of purchasing power from DG. They are Profit Percentage improvements, Percentage Loadshedding reduction, and Percentage Loading improvements. The calculated values of these are given below.

i Profit Percentage improvements

The net profit percentage improvement calculated is given below.

$$\text{PPI} = \frac{NP^{SP} - NP^{FS}}{NP^{FS}} \times 100\%$$

$$\text{PPI} = \frac{39,762 - 39,083}{39,083} \times 100\% \tag{5.6}$$

$$= 1.71\% \tag{5.7}$$

ii Percentage Improvement in Load shedding reduction

The net load shedding percentage reduction is calculated and is given below.

$$\text{LSI} = \frac{P_L^{SP}}{P_{LS}} \times 100\%$$

$$\text{LSI} = \frac{190.5}{190.5} \times 100\% \tag{5.8}$$

$$= 100\% \tag{5.9}$$

iii Percentage Loading improvements

Table 5.40 shows the percentage loading improvements in each transmission line of the system. The table shows the Average loading with and without DG. The average flow in all lines of the system is used in the last row to calculate the Percentage loading of the line. Table 5.41 performs the same calculations as Table 5.40 except that it performs on maximum flow of each line.

Branch Id	Without DG Average Percentage Loading (%)	With DG Average Percentage Loading (%)
1	78.02	79.15
2	83.00	83.52
3	81.64	80.89
4	80.78	80.15
5	78.67	77.95
6	75.75	72.75
7	82.96	82.77
8	78.84	78.30
9	73.81	73.31
10	76.56	76.53
11	76.40	75.39
12	70.97	71.10
13	76.10	74.38
14	0.00	0.00
15	78.84	78.30
16	64.03	62.21
17	68.90	58.76
18	68.89	64.49
19	58.69	49.91
20	68.46	55.36
Avg. Flow in all lines	71.06	68.76
Load Served	4546.40	4736.90
Percentage of total load served	95.98%	100%
Percentage loading	74.03%	68.76%

Table 5.40: Comparison of Forward and Spot Market Percentage Loading

Branch Id	Without DG Max Percentage Loading (%)	With DG Max Percentage Loading (%)
1	93.04	94.69
2	98.51	99.50
3	98.22	97.93
4	98.05	96.12
5	96.02	93.66
6	90.29	89.02
7	98.60	98.06
8	94.54	94.68
9	88.52	88.65
10	91.24	91.86
11	90.24	88.72
12	84.78	85.96
13	90.82	91.95
14	0.00	0.00
15	94.54	94.68
16	77.85	78.04
17	83.02	85.28
18	80.58	79.71
19	69.65	69.84
20	80.96	80.91
Av. Of Max Flow in all lines	84.97	84.96
Load Served	4546.40	4736.90
Percentage of total load served	95.98%	100%
Percentage loading	88.52%	84.96%

Table 5.41: Comparison of Forward and Spot Market max.Percentage Loading

Chapter 6

Summary and Future Work

6.1 Summary

This thesis presents a methodology to utilize distributed generation to minimize load shedding by optimizing the transactions between utility and distributed generators in a transactive energy framework. The proposed methodology has been analyzed in a 6 bus system and modified IEEE 14 bus system. The results shows that by optimizing the purchase of power from DG, there is significant improvement in load shedding in both test systems. Transactions in forward and spot market have been analyzed to account for three metrics of comparison namely Percentage Profit improvement, Percentage load shedding reduction, and Percentage Transmission Line Loading improvement. The proposed methodology shows improvements in all three metrics of benefit analysis.

The thesis is organized as six chapters. Chapter 1 presents the general introduction, historical review, and defines most of the terms used in this work. Literature review of various power markets and energy pricing is presented first, which is the foundational building blocks of this thesis. Next existing optimization techniques to achieve load flow and economic dispatch is introduced. Various researches showing the historical progress in the field of power system optimization is also presented here. Finally, Distributed energy resources and Transactive energy framework is outlined which is the fundamental concepts of this work. Chapter 2 is followed from the Chapter 1 literature review and presents the detailed mathematical formulation of majority of concepts used. Equations and techniques for existing power system optimization and LMP calculation are presented here. This is followed by analysis of different distributed generation technologies and their cost functions. Literature review performed in Chapter 1 is well surrounded by mathematical formulation here.

The foundation laid by Chapter 1 and 2 leads to Chapter 3. Here the thesis methodology is explained in detail using the algorithm developed in this work, and is well supported by mathematical formulation from Chapter 2. The algorithm consists of three main steps namely Power

System Optimization, Energy price Calculation, and Transactive Accounting. Optimization is performed in forward and spot market to analyze the benefit of purchasing power from DG. The results of transactions analyzed are then quantified using three matrix of benefit analysis namely Profit improvement, Percentage load shedding reduction, and Percentage Transmission Line Loading improvement. The purpose of this chapter was to describe the proposed methodology with necessary mathematical formulation.

The proposed method is studied on a six bus system and modified IEEE 14 bus power system to analyze the benefit of purchasing optimized power from DG. Chapter 4 introduces these two test systems where the study has been performed. Chapter 5 gives the results of proposed methodology in the test systems studied.

Results from Chapter 5 shows that by investing in DG utility makes profit in Real time Market. Utility is to make tenders with the customers in forward market and the load which is not satisfied in forward market may go to load shedding. However these excess loads are met in spot market by purchasing power from distributed generator. The algorithm tested in six bus and fourteen bus test systems shows that utility reduces its load shedding to 0% and makes profit by purchasing optimal power (calculated in this work) at the right buses from the distributed generators. In Real Time market the utility profit increases from \$73,387 to \$73,835 for a six bus sytem and \$39,083 to \$39,762 in a fourteen bus system by investing in Distributed Generator. The results has been studied using three metrics of analysis namely Profit Percentage improvement, Percentage Improvement in Load shedding reduction, and Percentage Loading improvements. Profit Percentage improvement for six and fourteen bus system are 0.61% and 1.71% respectively. Load shedding improvement is 100% for both the test systems. Percentage Loading shows an improvement from 61.80% to 60.13% for a six bus system and 74.03% to 68.76% for a fourteen bus system. Maximum percentage loading improvement is compared next and it shows an improvement from 83.68% to 82.11% and 88.52% to 84.96% for a six bus and fourteen bus systems respectively . Test results shows that the proposed algorithm improves the system performance and utility profit. The optimal power to be purchased from DG in Spot market which is calculated using the proposed algorithm is used to account the economics of power market in transactive energy framework.

6.2 Future Work

The following are some of the works that could be considered for future work.

- While one utility is considered in this study, interaction of distributed generators with the grid may be implemented between utilities for further development of the work.

- The optimal power flow results in this thesis are based on AC OPF using Newton-Raphson algorithm. Other existing optimization techniques described in previous chapters could be implemented instead of the one used in this work for faster convergence and/or better accuracy.

- While purchase of power by utilities in spot market alone is assumed in this thesis, the work could be extended to analyze a power market when DG's make direct tenders with customers in forward market. This could lead to either increase or decrease of power price in forward market. This may benefit utility or customer depending on the system topology where load at each bus and location of DG play a vital role.

- Although various DG technologies have been reviewed in this work, only one DG technology with fixed quadratic cost function is used in the simulation. The work could be extended to include different DG technologies with varying cost function to resemble an actual power system. The model of DG could be low power generating units such as a fuel cell or may be large units such as combined cycle gas turbines. Interaction of these units with the grid may be further studied for system stability and reliability analysis.

- System stability analysis could be studied in forward and spot market depending on the percentage of distributed generator penetration in the system. A contingency analysis with and without distributed generation would give the weakness of system and how a DG could improve system performance. This could also leads to potential buses where installing DG would result in monitory benefit for investors. Furthermore, a voltage stability analysis with and without DG may be performed to study the system weakness.

- Possible policies that affect optimization constraints may be explored such as in case of excess load in real time market, DG might be favored over Utility generators. Consumer payments and utility profit in spot market may be studied when preference is given to DG over UG.

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Appendix

Modified MATPOWER Case File for 6 bus system

```
function mpc = case6ww
mpc.version = '2';

%%-----  Power Flow Data  -----%%
%%- system MVA base
mpc.baseMVA = 100;

%%- bus data
%   bus_i   type    Pd  Qd  Gs  Bs  area    Vm  Va  baseKV  zone    Vmax    Vmin
mpc.bus = [
1   3   0   0   0   0   1   1   0   138 1   1.05    0.95;
2   2   0   0   0   0   1   1   0   138 1   1.05    0.95;
3   2   0   0   0   0   1   1   0   138 1   1.05    0.95;
4   2   70  70  0   0   1   1   0   138 1   1.05    0.95;
5   2   70  70  0   0   1   1   0   138 1   1.05    0.95;
6   2   70  70  0   0   1   1   0   138 1   1.05    0.95;
];

%% generator data
%   bus Pg  Qg  Qmax    Qmin    Vg  mBase   status  Pmax    Pmin    Pc1 Pc2 Qc1min  Qc1max
    Qc2min  Qc2max  ramp_agc    ramp_10 ramp_30 ramp_q  apf
mpc.gen = [
1   0   0   100 -100    1   100 1   200 50   0  0   0   0   0   0   0   0   0   0   0;
2   50  0   100 -100    1   100 1   150 37.5 0  0   0   0   0   0   0   0   0   0   0;
3   60  0   100 -100    1   100 1   180 45   0  0   0   0   0   0   0   0   0   0   0;
4   0   0   500 0         1   100 1   100   1   0  0   0   0   0   0   0   0   0   0   0;
5   0   0   500   0       1   100 1   100   1   0  0   0   0   0   0   0   0   0   0   0;
6   0   0   500   0       1   100 1   100   1   0  0   0   0   0   0   0   0   0   0   0;
];

%% branch data
%   fbus    tbus    r   x   b   rateA   rateB   rateC   ratio   angle   status  angmin
    angmax
```

```
mpc.branch = [
1   2   0.1     0.2     0.04    30  30  30  0   0   1   -360    360;
1   4   0.05    0.2     0.04    50  50  50  0   0   1   -360    360;
1   5   0.08    0.3     0.06    40  40  40  0   0   1   -360    360;
2   3   0.05    0.25    0.06    20  20  20  0   0   1   -360    360;
2   4   0.05    0.1     0.02    40  40  40  0   0   1   -360    360;
2   5   0.1     0.3     0.04    20  20  20  0   0   1   -360    360;
2   6   0.07    0.2     0.05    30  30  30  0   0   1   -360    360;
3   5   0.12    0.26    0.05    20  20  20  0   0   1   -360    360;
3   6   0.02    0.1     0.02    60  60  60  0   0   1   -360    360;
4   5   0.2     0.4     0.08    20  20  20  0   0   1   -360    360;
5   6   0.1     0.3     0.06    20  20  20  0   0   1   -360    360;
];


%%-----  OPF Data  -----%%
%%-- generator cost data
%   1   startup shutdown    n   x1  y1  ... xn  yn
%   2   startup shutdown    n   c(n-1)  ... c0
mpc.gencost = [
2   0   0   3   0   41.47   0;
2   0   0   3   0   25.77   0;
2   0   0   3   0   39.3    0;
2   0   0   3   0.003   43   0;
2   0   0   3   0.003   43   0 ;
2   0   0   3   0.003   43   0 ;
];


mpc.dglim.zones = [
1   1   1   0   0   0;
0   0   0   1   1   1;
];

mpc.dglim.req   = [15; 15; 15];

mpc.if.map = [
1   2;  %% 1 : area 1 imports
1   5;
2   7;  %% 2 : area 2 imports
2   8;
2   9;
```

```
];
% (negative and positive directions can be different)
%   ifnum   lower   upper
mpc.if.lims = [
1   -88 88; %% area 1 imports
2   -100 100    %% area 2 imports
];
```

Modified MATPOWER Case File for IEEE 14 bus system

```
function mpc = case14
%CASE14    Power flow data for IEEE 14 bus test case.
%   Please see CASEFORMAT for details on the case file format.
%   This data was converted from IEEE Common Data Format
%   (ieee14cdf.txt) on 15-Oct-2014 by cdf2matp, rev. 2393
%   See end of file for warnings generated during conversion.
%
%   Converted from IEEE CDF file from:
%       http://www.ee.washington.edu/research/pstca/
%
%  08/19/93 UW ARCHIVE           100.0  1962 W IEEE 14 Bus Test Case

%   MATPOWER
%   $Id: case14.m 2394 2014-10-15 20:39:39Z ray $

%% MATPOWER Case Format : Version 2
mpc.version = '2';

%%-----  Power Flow Data  -----%%
%% system MVA base
mpc.baseMVA = 100;

%% bus data
%   bus_i   type    Pd  Qd  Gs  Bs  area    Vm  Va  baseKV  zone    Vmax    Vmin
mpc.bus = [
1   3   0   0   0   0   1   1.06    0   0   1   1.06    0.94;
2   2   21.7    12.7    0   0   1   1.045   -4.98   0   1   1.06    0.94;
3   2   94.2    19  0   0   1   1.01    -12.72  0   1   1.06    0.94;
4   1   47.8    -3.9    0   0   1   1.019   -10.33  0   1   1.06    0.94;
5   1   7.6 1.6 0   0   1   1.02    -8.78   0   1   1.06    0.94;
6   2   11.2    7.5 0   0   1   1.07    -14.22  0   1   1.06    0.94;
7   1   0   0   0   0   1   1.062   -13.37  0   1   1.06    0.94;
8   2   0   0   0   0   1   1.09    -13.36  0   1   1.06    0.94;
9   1   29.5    16.6    0   19  1   1.056   -14.94  0   1   1.06    0.94;
10  1   9   5.8 0   0   1   1.051   -15.1   0   1   1.06    0.94;
11  1   3.5 1.8 0   0   1   1.057   -14.79  0   1   1.06    0.94;
12  1   6.1 1.6 0   0   1   1.055   -15.07  0   1   1.06    0.94;
```

```
13  1   13.5    5.8 0   0   1   1.05    -15.16  0   1   1.06    0.94;
14  1   14.9    5   0   0   1   1.036   -16.04  0   1   1.06    0.94;
];

%% generator data
%   bus Pg  Qg  Qmax    Qmin    Vg  mBase   status  Pmax    Pmin    Pc1 Pc2 Qc1min  Qc1max
    Qc2min  Qc2max  ramp_agc    ramp_10 ramp_30 ramp_q  apf
mpc.gen = [
1   232.4   -16.9   10  0   1.06    100 1   332.4   0   0   0   0   0   0   0   0   0   0
    0   0;
2   40  42.4    50  -40 1.045   100 1   140 0   0   0   0   0   0   0   0   0   0   0   0;
3   0   23.4    40  0   1.01    100 1   100 0   0   0   0   0   0   0   0   0   0   0   0;
6   0   12.2    24  -6  1.07    100 1   100 0   0   0   0   0   0   0   0   0   0   0   0;
8   0   17.4    24  -6  1.09    100 1   100 0   0   0   0   0   0   0   0   0   0   0   0;
];

%% branch data
%   fbus    tbus    r   x   b   rateA   rateB   rateC   ratio   angle   status  angmin
    angmax
mpc.branch = [
1   2   0.01938 0.05917 0.0528  0   0   0   0   0   1   -360    360;
1   5   0.05403 0.22304 0.0492  0   0   0   0   0   1   -360    360;
2   3   0.04699 0.19797 0.0438  0   0   0   0   0   1   -360    360;
2   4   0.05811 0.17632 0.034   0   0   0   0   0   1   -360    360;
2   5   0.05695 0.17388 0.0346  0   0   0   0   0   1   -360    360;
3   4   0.06701 0.17103 0.0128  0   0   0   0   0   1   -360    360;
4   5   0.01335 0.04211 0   0   0   0   0   0   1   -360    360;
4   7   0   0.20912 0   0   0   0   0.978   0   1   -360    360;
4   9   0   0.55618 0   0   0   0   0.969   0   1   -360    360;
5   6   0   0.25202 0   0   0   0   0.932   0   1   -360    360;
6   11  0.09498 0.1989  0   0   0   0   0   0   1   -360    360;
6   12  0.12291 0.25581 0   0   0   0   0   0   1   -360    360;
6   13  0.06615 0.13027 0   0   0   0   0   0   1   -360    360;
7   8   0   0.17615 0   0   0   0   0   0   1   -360    360;
7   9   0   0.11001 0   0   0   0   0   0   1   -360    360;
9   10  0.03181 0.0845  0   0   0   0   0   0   1   -360    360;
9   14  0.12711 0.27038 0   0   0   0   0   0   1   -360    360;
10  11  0.08205 0.19207 0   0   0   0   0   0   1   -360    360;
12  13  0.22092 0.19988 0   0   0   0   0   0   1   -360    360;
13  14  0.17093 0.34802 0   0   0   0   0   0   1   -360    360;
];
```

```
%%-----  OPF Data  -----%%
%% generator cost data
%   1   startup shutdown    n   x1  y1  ... xn  yn
%   2   startup shutdown    n   c(n-1)  ... c0
mpc.gencost = [
2   0   0   3   0.0430292599    20  0;
2   0   0   3   0.25    20  0;
2   0   0   3   0.01    40  0;
2   0   0   3   0.01    40  0;
2   0   0   3   0.01    40  0;
];

%% bus names
mpc.bus_name = {
'Bus 1     HV';
'Bus 2     HV';
'Bus 3     HV';
'Bus 4     HV';
'Bus 5     HV';
'Bus 6     LV';
'Bus 7     ZV';
'Bus 8     TV';
'Bus 9     LV';
'Bus 10    LV';
'Bus 11    LV';
'Bus 12    LV';
'Bus 13    LV';
'Bus 14    LV';
};

% Warnings from cdf2matp conversion:
%
% ***** check the title format in the first line of the cdf file.
% ***** Qmax = Qmin at generator at bus    1 (Qmax set to Qmin + 10)
% ***** MVA limit of branch 1 - 2 not given, set to 0
% ***** MVA limit of branch 1 - 5 not given, set to 0
% ***** MVA limit of branch 2 - 3 not given, set to 0
% ***** MVA limit of branch 2 - 4 not given, set to 0
% ***** MVA limit of branch 2 - 5 not given, set to 0
% ***** MVA limit of branch 3 - 4 not given, set to 0
% ***** MVA limit of branch 4 - 5 not given, set to 0
% ***** MVA limit of branch 4 - 7 not given, set to 0
```

```
% ***** MVA limit of branch 4 - 9 not given, set to 0
% ***** MVA limit of branch 5 - 6 not given, set to 0
% ***** MVA limit of branch 6 - 11 not given, set to 0
% ***** MVA limit of branch 6 - 12 not given, set to 0
% ***** MVA limit of branch 6 - 13 not given, set to 0
% ***** MVA limit of branch 7 - 8 not given, set to 0
% ***** MVA limit of branch 7 - 9 not given, set to 0
% ***** MVA limit of branch 9 - 10 not given, set to 0
% ***** MVA limit of branch 9 - 14 not given, set to 0
% ***** MVA limit of branch 10 - 11 not given, set to 0
% ***** MVA limit of branch 12 - 13 not given, set to 0
% ***** MVA limit of branch 13 - 14 not given, set to 0
```

IEEE 14 bus system .raw file [16]

```
0,   100.00, 33, 0, 0, 60.00      / October 01, 2013 18:37:53
08/19/93 UW ARCHIVE           100.0  1962 W IEEE 14 Bus Test Case

1,'Bus 1       ', 138.0000,3,   1,   1,   1,1.06000,   0.0000
2,'Bus 2       ', 138.0000,2,   1,   1,   1,1.04500,  -4.9826
3,'Bus 3       ', 138.0000,2,   1,   1,   1,1.01000, -12.7250
4,'Bus 4       ', 138.0000,1,   1,   1,   1,1.01767, -10.3128
5,'Bus 5       ', 138.0000,1,   1,   1,   1,1.01951,  -8.7738
6,'Bus 6       ', 138.0000,2,   1,   1,   1,1.07000, -14.2209
7,'Bus 7       ', 138.0000,1,   1,   1,   1,1.06152, -13.3596
8,'Bus 8       ', 138.0000,2,   1,   1,   1,1.09000, -13.3596
9,'Bus 9       ', 138.0000,1,   1,   1,   1,1.05593, -14.9385
10,'Bus 10      ', 138.0000,1,   1,   1,   1,1.05099, -15.0972
11,'Bus 11      ', 138.0000,1,   1,   1,   1,1.05691, -14.7906
12,'Bus 12      ', 138.0000,1,   1,   1,   1,1.05519, -15.0755
13,'Bus 13      ', 138.0000,1,   1,   1,   1,1.05038, -15.1562
14,'Bus 14      ', 138.0000,1,   1,   1,   1,1.03553, -16.0336
0 / END OF BUS DATA, BEGIN LOAD DATA
2,'1 ',1,   1,   1,    21.700,    12.700,     0.000,     0.000,     0.000,    -0.000,   1,1
3,'1 ',1,   1,   1,    94.200,    19.000,     0.000,     0.000,     0.000,    -0.000,   1,1
4,'1 ',1,   1,   1,    47.800,    -3.900,     0.000,     0.000,     0.000,    -0.000,   1,1
5,'1 ',1,   1,   1,     7.600,     1.600,     0.000,     0.000,     0.000,    -0.000,   1,1
6,'1 ',1,   1,   1,    11.200,     7.500,     0.000,     0.000,     0.000,    -0.000,   1,1
9,'1 ',1,   1,   1,    29.500,    16.600,     0.000,     0.000,     0.000,    -0.000,   1,1
10,'1 ',1,   1,   1,     9.000,     5.800,     0.000,     0.000,     0.000,    -0.000,   1,1
11,'1 ',1,   1,   1,     3.500,     1.800,     0.000,     0.000,     0.000,    -0.000,   1,1
12,'1 ',1,   1,   1,     6.100,     1.600,     0.000,     0.000,     0.000,    -0.000,   1,1
13,'1 ',1,   1,   1,    13.500,     5.800,     0.000,     0.000,     0.000,    -0.000,   1,1
14,'1 ',1,   1,   1,    14.900,     5.000,     0.000,     0.000,     0.000,    -0.000,   1,1
0 / END OF LOAD DATA, BEGIN FIXED SHUNT DATA
9,' 1', 1,     0.000,    19.000
0 / END OF FIXED SHUNT DATA, BEGIN GENERATOR DATA
1,'1 ',   232.392,   -16.549,     0.000,     0.000,1.06000,    0,   615.000,   0.00000,
    1.00000,   0.00000,   0.00000,1.00000,1,  100.0, 10000.000,-10000.000,   1,1.0000,
    0,1.0000,   0,1.0000,   0,1.0000,0, 1.0000
2,'1 ',    40.000,    43.556,    50.000,   -40.000,1.04500,    0,    60.000,   0.00000,
    1.00000,   0.00000,   0.00000,1.00000,1,  100.0, 10000.000,-10000.000,   1,1.0000,
```

```
    0,1.0000,   0,1.0000,   0,1.0000,0, 1.0000
3,'1 ',     0.000,    25.075,    40.000,     0.000,1.01000,    0,    60.000,   0.00000,
    1.00000,   0.00000,   0.00000,1.00000,1,  100.0, 10000.000,-10000.000,   1,1.0000,
    0,1.0000,   0,1.0000,   0,1.0000,0, 1.0000
6,'1 ',     0.000,    12.730,    24.000,    -6.000,1.07000,    0,    25.000,   0.00000,
    1.00000,   0.00000,   0.00000,1.00000,1,  100.0, 10000.000,-10000.000,   1,1.0000,
    0,1.0000,   0,1.0000,   0,1.0000,0, 1.0000
8,'1 ',     0.000,    17.623,    24.000,    -6.000,1.09000,    0,    25.000,   0.00000,
    1.00000,   0.00000,   0.00000,1.00000,1,  100.0, 10000.000,-10000.000,   1,1.0000,
    0,1.0000,   0,1.0000,   0,1.0000,0, 1.0000
0 / END OF GENERATOR DATA, BEGIN BRANCH DATA
1,     2,'1 ', 0.01938, 0.05917,0.05280,   0.00,   0.00,   0.00, 0.00000, 0.00000,
    0.00000,  0.00000,1,1,   0.0,   1,1.0000,   0,1.0000,   0,1.0000,   0,1.0000
1,     5,'1 ', 0.05403, 0.22304,0.04920,   0.00,   0.00,   0.00, 0.00000, 0.00000,
    0.00000,  0.00000,1,1,   0.0,   1,1.0000,   0,1.0000,   0,1.0000,   0,1.0000
2,     3,'1 ', 0.04699, 0.19797,0.04380,   0.00,   0.00,   0.00, 0.00000, 0.00000,
    0.00000,  0.00000,1,1,   0.0,   1,1.0000,   0,1.0000,   0,1.0000,   0,1.0000
2,     4,'1 ', 0.05811, 0.17632,0.03400,   0.00,   0.00,   0.00, 0.00000, 0.00000,
    0.00000,  0.00000,1,1,   0.0,   1,1.0000,   0,1.0000,   0,1.0000,   0,1.0000
2,     5,'1 ', 0.05695, 0.17388,0.03460,   0.00,   0.00,   0.00, 0.00000, 0.00000,
    0.00000,  0.00000,1,1,   0.0,   1,1.0000,   0,1.0000,   0,1.0000,   0,1.0000
3,     4,'1 ', 0.06701, 0.17103,0.01280,   0.00,   0.00,   0.00, 0.00000, 0.00000,
    0.00000,  0.00000,1,1,   0.0,   1,1.0000,   0,1.0000,   0,1.0000,   0,1.0000
4,     5,'1 ', 0.01335, 0.04211,0.00000,   0.00,   0.00,   0.00, 0.00000, 0.00000,
    0.00000,  0.00000,1,1,   0.0,   1,1.0000,   0,1.0000,   0,1.0000,   0,1.0000
6,    11,'1 ', 0.09498, 0.19890,0.00000,   0.00,   0.00,   0.00, 0.00000, 0.00000,
    0.00000,  0.00000,1,1,   0.0,   1,1.0000,   0,1.0000,   0,1.0000,   0,1.0000
6,    12,'1 ', 0.12291, 0.25581,0.00000,   0.00,   0.00,   0.00, 0.00000, 0.00000,
    0.00000,  0.00000,1,1,   0.0,   1,1.0000,   0,1.0000,   0,1.0000,   0,1.0000
6,    13,'1 ', 0.06615, 0.13027,0.00000,   0.00,   0.00,   0.00, 0.00000, 0.00000,
    0.00000,  0.00000,1,1,   0.0,   1,1.0000,   0,1.0000,   0,1.0000,   0,1.0000
7,     8,'1 ', 0.00000, 0.17615,0.00000,   0.00,   0.00,   0.00, 0.00000, 0.00000,
    0.00000,  0.00000,1,1,   0.0,   1,1.0000,   0,1.0000,   0,1.0000,   0,1.0000
7,     9,'1 ', 0.00000, 0.11001,0.00000,   0.00,   0.00,   0.00, 0.00000, 0.00000,
    0.00000,  0.00000,1,1,   0.0,   1,1.0000,   0,1.0000,   0,1.0000,   0,1.0000
9,    10,'1 ', 0.03181, 0.08450,0.00000,   0.00,   0.00,   0.00, 0.00000, 0.00000,
    0.00000,  0.00000,1,1,   0.0,   1,1.0000,   0,1.0000,   0,1.0000,   0,1.0000
9,    14,'1 ', 0.12711, 0.27038,0.00000,   0.00,   0.00,   0.00, 0.00000, 0.00000,
    0.00000,  0.00000,1,1,   0.0,   1,1.0000,   0,1.0000,   0,1.0000,   0,1.0000
10,    11,'1 ', 0.08205, 0.19207,0.00000,   0.00,   0.00,   0.00, 0.00000, 0.00000,
    0.00000,  0.00000,1,1,   0.0,   1,1.0000,   0,1.0000,   0,1.0000,   0,1.0000
```

```
12,    13,'1 ', 0.22092, 0.19988,0.00000,   0.00,   0.00,   0.00,  0.00000,  0.00000,
    0.00000,  0.00000,1,1,   0.0,   1,1.0000,   0,1.0000,   0,1.0000,   0,1.0000
13,    14,'1 ', 0.17093, 0.34802,0.00000,   0.00,   0.00,   0.00,  0.00000,  0.00000,
    0.00000,  0.00000,1,1,   0.0,   1,1.0000,   0,1.0000,   0,1.0000,   0,1.0000
0 / END OF BRANCH DATA, BEGIN TRANSFORMER DATA
4,    7,    0,'1 ',1,1,1,  0.00000,  0.00000,2,'        ',1,   1,1.0000,   0,1.0000,
    0,1.0000,   0,1.0000
0.00000, 0.20912, 100.00
0.97800,  0.000,   0.000,   0.00,   0.00,   0.00,0,     0, 1.50000, 0.51000, 1.50000,
    0.51000,159, 0, 0.00000, 0.00000
1.00000,  0.000
4,    9,    0,'1 ',1,1,1,  0.00000,  0.00000,2,'        ',1,   1,1.0000,   0,1.0000,
    0,1.0000,   0,1.0000
0.00000, 0.55618, 100.00
0.96900,  0.000,   0.000,   0.00,   0.00,   0.00,0,     0, 1.50000, 0.51000, 1.50000,
    0.51000,159, 0, 0.00000, 0.00000
1.00000,  0.000
5,    6,    0,'1 ',1,1,1,  0.00000,  0.00000,2,'        ',1,   1,1.0000,   0,1.0000,
    0,1.0000,   0,1.0000
0.00000, 0.25202, 100.00
0.93200,  0.000,   0.000,   0.00,   0.00,   0.00,0,     0, 1.50000, 0.51000, 1.50000,
    0.51000,159, 0, 0.00000, 0.00000
1.00000,  0.000
0 / END OF TRANSFORMER DATA, BEGIN AREA DATA
1,    2,     0.000,   999.990,'IEEE14      '
0 / END OF AREA DATA, BEGIN TWO-TERMINAL DC DATA
0 / END OF TWO-TERMINAL DC DATA, BEGIN VOLTAGE SOURCE CONVERTER DATA
0 / END OF VOLTAGE SOURCE CONVERTER DATA, BEGIN IMPEDANCE CORRECTION DATA
0 / END OF IMPEDANCE CORRECTION DATA, BEGIN MULTI-TERMINAL DC DATA
0 / END OF MULTI-TERMINAL DC DATA, BEGIN MULTI-SECTION LINE DATA
0 / END OF MULTI-SECTION LINE DATA, BEGIN ZONE DATA
1,'IEEE 14 '
0 / END OF ZONE DATA, BEGIN INTER-AREA TRANSFER DATA
0 / END OF INTER-AREA TRANSFER DATA, BEGIN OWNER DATA
1,'1'
0 / END OF OWNER DATA, BEGIN FACTS CONTROL DEVICE DATA
0 / END OF FACTS CONTROL DEVICE DATA, BEGIN SWITCHED SHUNT DATA
0 /END OF SWITCHED SHUNT DATA, BEGIN GNE DEVICE DATA
0 /END OF GNE DEVICE DATA
Q
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Vita

Nandu Balachandran received his Bachelor Degree in Electrical and Electronics Engineering from Mahatma Gandhi University, India in 2012. He joined the University of New Orleans for Electrical Engineering Master of Science program in Fall 2013. He started working as a Research Assistant in Power & Energy Research Laboratory at University of New Orleans under the supervision of Dr. Parviz Rastgoufard. He have been doing active research in Power system modelling and testing power system instruments. His research interest includes Power system economics, System Optimization, Smart Grids, and Real Time Simulation studies. He is a member of IEEE professional organization since January 2008.