CONTROLLABLE LINE PRICING

by

Abdiel Ayala Acevedo

A thesis submitted in partial fulfillment of the requirements for the degree of

MASTER OF SCIENCE
in
ELECTRICAL ENGINEERING

UNIVERSITY OF PUERTO RICO
MAYAGÜEZ CAMPUS
2009

Approved by:

Alberto Ramírez Orquin, Ph.D. President, Graduate Committee	Date
Lionel Orama Exclusa, D. Eng. Member, Graduate Committee	Date
Erick E. Aponte, D. Eng. Member, Graduate Committee	Date
William Hernández Rivera, Ph.D. Representative, Graduate Studies	Date
Isidoro Couvertier, Ph.D. Department Chair	Date

ABSTRACT

CONTROLLABLE LINE PRICING

By

Abdiel Ayala Acevedo

This thesis studies the circumstances in which power scheduled to flow over a controllable line from a particular source would be priced differently than one delivered from that source but through free-flowing lines. This work also studies several factors that affect pricing of energy scheduled to flow over controllable lines. The purpose of this investigation is to study the impact on electricity pricing, specifically on the locational marginal price (LMP). Moreover, the interest is to make the point that by being able to control a specific line in the system it can be able to control the flow at large, in the system during a time period, and thus reducing the price of energy. In addition, this concept of controllable lines can be applied, in generic terms, onto an energy market. The reason for pursuing this investigation is to study the impact of congestion on LMP as an issue of major importance. Since transmission networks increase generating costs as well as making markets less competitive compensation methods like this can help to optimize the price of energy and make them more cost effective. During this investigation a five-bus system was simulated and several case studies were performed. The study started with system without congestion, followed by single-contingency and binding constraints with controllable lines present. Results were obtained for each case and after analyzing the results it can be concluded that controllable lines help us achieve greater efficiency in the power system.

RESUMEN

PRECIO DE LA ENERGÍA ELÉCTRICA BAJO CONDICIONES DE TRANSMISIÓN CONTROLABLE

Por
Abdiel Ayala Acevedo

Esta tesis estudia las circunstancias en las que potencia programada para fluir a través de una línea de transmisión controlable pueda devengar un precio distinto al de la potencia emitida a partir de esa misma fuente, pero por una línea de flujo libre, no controlado. Este trabajo identifica además los factores que gravitan sobre el precio de energía programada para fluir sobre líneas dotadas de tecnología de control. El propósito de esta investigación es el de estudiar el impacto que tienen líneas controlables específicamente en el precio marginal de la electricidad (LMP). Además, interesa probar el punto de que siendo capaz de controlar el flujo de potencia en una línea específica del sistema se puede reducir el precio de la energía. Queremos aplicar el concepto de líneas controlables en un mercado de potencia centralizada (pool). La razón para realizar esta pesquisa se puede encontrar en el impacto que la congestión de redes de transmisión tiene en el costo marginal, como una cuestión de importancia para todos los mercados de potencia. Más aún, la congestión de la red aumenta los costos de generación; consecuentemente los métodos de compensación de este tipo ayudan a optimizar el precio de la energía. Durante esta investigación se simuló un sistema de transmisión con cinco barras y se realizaron estudios de varios casos alternativos, cotejando con un sistema libre de restricciones de congestión, con contingencia simple y con líneas controlables presentes en el mismo. Se obtuvieron resultados para cada caso y luego de analizarlos críticamente se puede concluir que las líneas controlables coadyuvan notoriamente a la obtención de mayores eficiencias y ergo a la optimización en el precio de la energía.

To God and my family . . .

ACKNOWLEDGEMENTS

During the development of my graduate studies in the University of Puerto Rico several people collaborated directly and indirectly with my research. Without their support, it would have been impossible to finish my work. That is why I wish to dedicate this section to recognize their support.

I want to start expressing a sincere acknowledgement to my advisor, Dr. Alberto Ramírez Orquin because he gave me the opportunity to research under his guidance and supervision. I received motivation; encouragement and support from him during all my studies. I also want to acknowledge my graduate committee, Dr. Lionel Orama Exclusa and Dr. Erick E. Aponte for their involvement during the final portion of the research study. I am completely grateful to all of them.

Last but not least, I would like to thank God for guiding me throughout the years of my life, and for giving me the strength and courage to finish this work. I thank my family for their love and support during these difficult times. I would also like to extend a note of gratitude to all my friends for their support during the project.

Table of Contents

Table List

Tables **Page**

Figure List

Figures **Page**

1 INTRODUCTION

1.1 Motivation

Electrical energy is essential and necessary to modern life. The impact of transmission network congestion on locational marginal prices (LMP) has been a key issue since the commencement of the National Electricity Market. Open access to the transmission network has resulted in a problem of management of the transmission system due to congestion. The condition where overloads in transmission lines occur is called congestion and transmission congestion is a major problem that needs more studies. Congestion occurs when the transmission network is not sufficient to transfer electric power according to the market desire. In Power Systems, transmission networks provide the infrastructure to support a competitive electricity market. However, congestion occurs frequently in weakly connected networks. Congestion causes relative scarcity of generating capacities in the congested areas, so generation companies in these areas have locational market power.

Transmission networks play a major role in the open access power market. Congestion segregates the power market, weakens the competition mechanism, and invalidates the optimization of the generating resources in the whole network. Congestion also increases generating costs and makes the power market less efficient. In order to optimize the generating resources and increase the market efficiency, the market operation department should pay attention to the transmission congestion and eliminate the congestion through deploying various physical or financial means [1]. Managing transmission congestion in an unbundled electric power system poses a challenge to an Independent

System Operator (ISO). In an open-access environment, transmission constraints can result in different energy prices throughout the network. These prices are, dependent on a number of factors such as: the generating unit bid; system load level; network topology; security limits imposed on the transmission network due to thermal, and voltage and stability considerations.[1]

1.2 Literature Review

1.2.1 TRANSMISSION CONGESTION

Transmission networks play a major role in the open access deregulated power market. The condition where overloads in transmission lines occur is called congestion and transmission congestion is a major problem that needs to be studied further [2]. Kirchhoff's laws and the impedance of the whole network determine the power flows in a system. Since power cannot be stored on large scale and the short-term elasticity of the loads is very small. So when there is congestion, the preferred pre-dispatch plan of the generating units has to be changed in order to meet energy requirements and maintain system security. Thus, the more cost effective units in the congestion free areas should reduce their outputs and, on the contrary, the more expensive units in the congested areas will supply more energy. Thus, congestion makes the power market less efficient. Because the short-term elasticity of loads is very small in a power market, short-term loads can be considered as inelastic loads for simplicity. If we ignore the losses and consider no congestion the LMP's of the whole network differ. When congestion is considered, the LMP's of the whole network are different. When there is congestion in the power system, the total outputs of generators in an area will increase by ΔP_i, while the total outputs of generators in another area will reduce by ΔP_j. So, the LMP's in the first area will increase, while the LMP's in the second area will decrease. As a result of the congestion, the system operator has to change the pre-dispatch generating plan. Consequently the outputs of the generators and LMP's change, so the income of each company and market efficiency also change. Transmission congestion occurs when actual or scheduled flows of electricity across a line or piece of equipment are restricted below desired levels, either by physical or electrical capacity of the line, or by operational restrictions created and enforced to protect the security and reliability of the grid. The term transmission constraint may refer either to a piece of equipment that limits electricity flows in physical terms, or to an operational limit imposed to protect reliability. There are many ways to measure transmission congestion. There are metrics related to the magnitude and impact of congestion and the cost of congestion. The cost of congestion varies in real time according to: changes in the levels and patterns of customers demand; the availability of output from various generation sources; the cost of generation fuels; and the availability of transmission capacity. Transmission constraints that occur in most areas of the nation and the cost of the congestion they cause is included, to some degree, in virtually every customer's electricity bill. Although congestion is costly, in many locations those costs are not sufficient to justify making the investments needed to alleviate the congestion. In other locations, however, congestion costs can be very high.

1.2.2 IMPACTS OF TRANSMISSION CONGESTION ON LMP

Impacts of transmission congestion on generator market power can affect their settlement prices. Because optimal power flow (OPF) can be used in the locational marginal price to manage transmission congestion and it can reflect marginal cost of the load in the bus. So LMP is used in many electricity markets like Pennsylvania, New Jersey, Maryland (PJM) and independent system operator New England (ISO-NE). Impacts of transmission congestion on generators power market are analyzed most of the time, based on LMP calculation [3]. LMPs are determined by three components: energy costs, network losses and congestion costs. When there is no congestion and losses are neglected, the LMP’s of all buses are equal. When congestion is considered, the LMPs of the whole network is different. It should be mentioned that the inclusion of line losses and reactive power in the assessment, as described above, could result in higher LMP’s. When there is congestion in the power system, the total outputs of generators in area A will increase by a certain amount, while the total outputs of generators in area B will reduce by a certain amount also. So, the LMPs in area A will increase, while the LMP’s in area B will decrease. As a result, the system operator has to change the pre-dispatch generating plan, and the outputs of the generators and LMPs change, so the income of each company and market efficiency also change.

One way to include line losses in the LMP calculations is to modify the system load profile for the study period to reflect line losses. This can be accomplished by adding a fixed or variable amount of load to the hourly load curve. The additional amount of load represents the total system losses that can be estimated or calculated depending on the accuracy required. The modified load curve is then used to establish a new base case and LMPs.

1.2.3 TRANSMISSION DISPATCH

The future transmission dispatch scenario will be a mix of pool and bilateral/multilateral transactions. The ideal is to deliver all bilateral and multilateral transactions in full and to supply all pool demand at least cost. This may not be possible to do since power flow equations and operating constraints must be satisfied. Therefore, a two-stage dispatch process is proposed. The normal condition is when all pool demand and all bilateral and multilateral transactions are dispatched without system security violations. All these transactions will be serviced at their desired value and the IS0 only needs to optimize pool dispatch and ancillary services. Hence a slightly modified traditional optimal power flow follows. Congestion occurs when the dispatch of all pool and bilateral and multilateral transactions in full result in the violation of operational constraints. Market participants should have the right to minimize curtailment through competition. Pool and bilateral/multilateral participants may be willing to make extra payment, reflected in the weights to avoid curtailment. These extra payment rates may be agreed in advance and the IS0 should determine appropriate weights accordingly. The weights, therefore, are called willingness-to-pay-to-avoid-curtailment factors. They describe how the shortfall will be spread across the loads of a group when the supplies in the group have to be curtailed. For example, if group power input has to be curtailed then all loads in the group can be curtailed proportionally, if they are of equal importance. These relations will be declared by bilateral/multilateral participants in advance.

1.3 Problem Definition

The purpose of this investigation is to study the impact that controllable lines have on the locational marginal price. The reason for pursuing this investigation is because the impact of transmission network congestion on locational marginal prices is an issue of importance to all national electricity markets. Congestion occurs when the transmission network is not sufficient to transfer electric power according to the market desire. For this reason, there is a desire to be able to reduce the price of energy in a specific location in the system when it is subject to congestions or to single contingency which is when it's mainly when the price increases. This situation is present specifically when there are high-price generators actively selling energy during the time when congestions occur. By being able to control a specific line in the system, we are able to control the flow in a location in the system and reduce the amount of energy needed from a high-price generator. During this investigation we will analyze a small five bus system modeled using the Power World simulation software. The reason for choosing this system over a bigger one is to avoid complications to the study and focus on the concepts and analysis of the system than on the amount of elements that where included in the system. Unlike the network models that are being used in advanced network applications, the objective of the commercial network model is to provide pricing locations for trading. Locations provide points in the system where participants submit offers and bids, markets settle, and LMP's are calculated. Location is not necessarily a physical point in the electrical network model.

Once the system is simulated the procedure is to calculate the LMP's without contingency. Followed by an analysis of how the system responds to single contingencies by removing one line at a time to the system and see how the prices at each location are affected by this. This is done to be able to identify the worst case scenario when the highest price is obtained. Finally, there should be a study of how the system responds when the controllable line is with and without single contingency, and how the price can be improved.

1.4 Objectives

The objectives of this work are:

1. Analyze the impact of transmission congestion networks on electrical energy price.
2. Study the procedures, concepts and criteria used by electricity markets of today and how they operate.
3. Generate various simulations of transmission networks with the Power World program and study how the price is affected when a specific line in the system is being controlled when it is subject to congestion.
4. Find the optimal power flow solution for different types of congestions and analyze their feasibility.
5. Compare and determine the advantages and disadvantages of power systems with and without congestion.

1.5 Procedure

The following processes were performed to accomplish the objectives of this work:

1. Literature review and selection of relevant previous work published regarding transmission network congestions.
2. Identify standards and regulations used by electricity markets that help determine their operation.
3. Generate various simulations of power system transmission networks with the help of the Power World software and make use of different scenarios to run each simulation.
4. Confirm the results obtained from the simulation program by computing the outputs of generation companies, and their LMP with and without congestion. Also compute the revenues, generating costs and profits of generation companies with and without congestion.
5. Gather results and compare different scenarios to verify the contribution of each generation company for each case as well the advantages and disadvantages of each scenario.
6. Make a thorough analysis of the economic impact of transmission congestion networks on locational marginal price.

2 LOCATIONAL MARGINAL PRICE

2.1 What is Locational Marginal Price?

The Locational Marginal Price is a market-pricing approach used to manage the efficient use of a transmission system when congestion occurs on the bulk power grid. The Federal Energy Regulatory Commission (FERC) has proposed locational marginal price as a way to achieve short and long term efficiency in wholesale electricity markets. Marginal pricing is the idea that the market price of any commodity should be the cost of bringing the last unit of that commodity to market. In electricity, LMP recognizes that this marginal price may vary at different times and locations based on transmission congestion. With Locational Marginal Price, market participants will know the price of hundreds of locations on the system.

The LMP at a specific location reflects the marginal cost in serving the last mega watt of load considering the marginal production cost, the impact of locational injections on congestion constraints, and in some cases, the marginal effect of transmission losses. The formulation for the LMP calculation is as follows:

$$\lambda_i = \frac{dL}{d\Delta P_{gi}}$$

Where

L: means the Lagrange function, see equation.

P_{gi}: Decision variables for generation dispatch of unit i

In base case solution of security constrained economic dispatch, sinusoidal function of the flow is replaced with a linear function using the linearization method. Since, sensitivity is one way of linearization; it shows how a power flow variable (flow, voltage, phase angle) changes with the change of another value (injection, flow). The most used sensitivities in electric network analysis are power transfer distribution factors (PTDF) and loss factors (LF). Power transfer distribution factor determines a change in the power flow at each line when 1 MW is transferred from one bus of the network to another [3]. In addition, depending on the location of the two buses, the transfer causes different losses that are impossible to predict, so reference bus or swing bus makes up for losses injecting additional MW's. This means that PTDF are dependent on the selection of the reference bus. Shift factors (SF) are the PTDF when one of the points is always a reference bus. In other words, shift factor is the sensitivity of the line flows to the change in injections at the buses. Shift factor shows how the flow in the branch will change if the injection at the bus changes by 1 MW. Because the reference bus always makes up for the change in the injection, shift factor values are dependent on the location of the reference bus. By definition, the shift factor at the reference bus equals to 0. Loss factor is the sensitivity of system losses to a change in the injection at the bus. In other words, a loss factor at the bus shows how system losses will change if the injection at the bus is changed by 1 MW. Because the reference bus always makes up for this additional MW, the values of the loss factors are dependent on the selection of the reference bus. By definition, the loss factor at the reference bus equals to 0.

While dispatched, all units will end up in one of the three groups:

- At the maximum limit;
- At the minimum limit;
- Between minimum and maximum.

The third group of units is called Marginal Units. These are the units that determine LMP's at all locations. The price at the location of each marginal unit is always equal to its offer price. The n+1 rule states that for n binding constraints, there is at least n+1 marginal unit`s. This does not include equality constraint. In the case of no congestion, there is only one marginal unit.

Any increment of load at a particular location will be delivered from the marginal units. So an LMP at any location will be a linear combination of the LMP's at marginal locations. If there is no congestion and no losses, the LMP will be the same at each location.

The LMP has three components. The first term, the energy component, equals to system marginal price assuming there is no loss and no transmission constraints. The energy component is the same for all locations and equals to the system balance shadow price. The second term is the loss component, it's the marginal cost of additional losses caused by supplying an increment of load at the location. The third term is the congestion components, presents the change in the marginal price due to transmission constraints. Congestion components equal zero for all locations if there are no binding constraints. At the reference bus, the loss factor and all shift factors are equal to zero. This means that both loss and congestion components are always zero at the reference bus. As a result, the price at the reference bus always equals to the energy component. LMP will not change when the reference bus is changed from one location to another. However, all three components are dependent on the selection of the reference bus due to the dependency of the sensitivities on the location of the reference bus. The dependency of components on the selection of the reference bus proves that the value of each component by itself do not have significant value. Only the differences have a meaning and are not dependent on the selection of the reference bus.

Transmission network congestion occurs when one or more restrictions on the transmission system prevent the economic, or least expensive, supply of energy from serving the demand. For example, transmission lines may not have enough capacity to carry all the electricity demand required to meet the demand at a specific location. This is called a transmission constraint. Locational Marginal Price includes the cost of supplying the more expensive electricity, thus providing a precise, market-based method for pricing energy that includes the cost of congestion. Locational Marginal Price provides market participants a clear and accurate signal of the price of electricity at every location on the grid. These prices, in turn, reveal the value of locating new generation, upgrading transmission, or reducing electricity consumption. Elements needed in a well functioning market to alleviate constraints, increase competition and improve the systems ability to meet power demand.

These location specific prices are made up of three components: energy, congestion and losses. The energy component is defined as the cost to serve the next increment of demand at the specific location, produced by least expensive generating unit in the system that still has available capacity.

However, if the transmission network is congested, the next increment of energy cannot be delivered from the least expensive unit on the system because it would cause overloading on the transmission system. It would also violate transmission operating criterias, such as voltage requirements. The congestion component is calculated at a node as the difference between the energy component of the price and the cost of providing the additional energy that can be delivered to that location. It can also be negative in export-constrained areas where there is more generation than demand.

All transmission systems experience electrical losses, which occur as electricity is sent over transmission lines and accounts for a small percentage of electricity from generators. Nodal prices are adjusted to account for the marginal cost of losses.

If the system was entirely unconstrained and there were no losses, all of the LMP would be equal and would reflect only the energy price. The lowest possible cost generation could flow to all nodes over the transmission system.

The real-time LMP calculation process consists of several programming modules that are executed as part of the real-time sequence. A functional diagram of the LMP model is shown below. As indicated in figure 2.1, the main modules of the model are: unit dispatch system, state estimator, locational pricing algorithm (LPA) preprocessor and locational pricing algorithm [4].

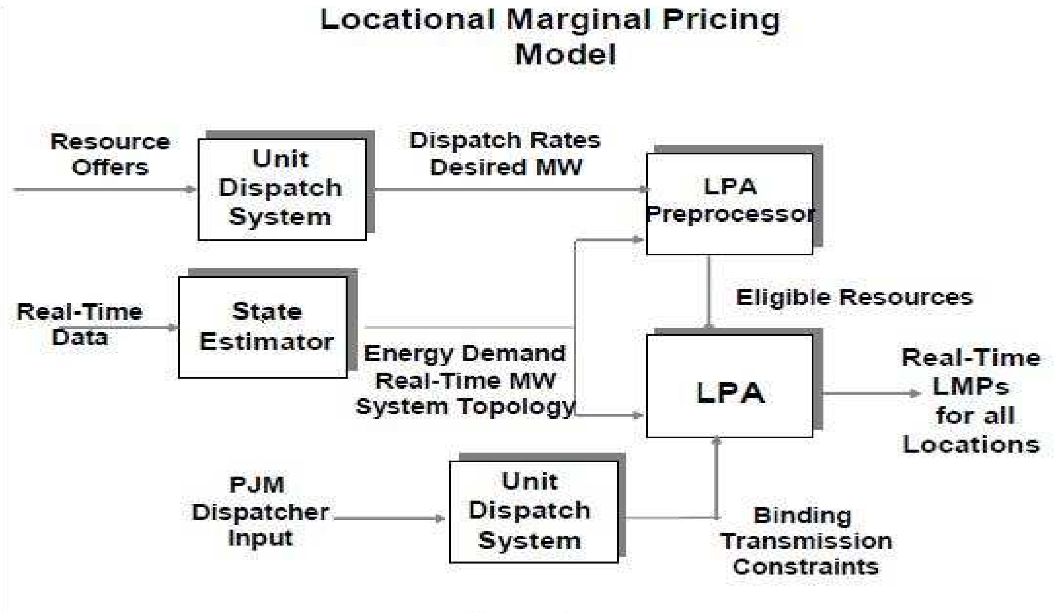


Figure 2.1: LMP model

Generators are paid nodal LMP. Standard market design (SMD) rules assure that generators recover their offer or bid-in costs, including start-up and no load costs for all energy generated. If a generator operates in-merit, most of its compensation will be from the energy market, unless the energy revenues are insufficient to cover its costs. If higher priced generation is dispatched to relieve congestion, the higher cost for this generation is borne by the location in which it occurs through higher LMP that those locations must pay. In the original market, these costs are absorbed by all loads across the New England system, regardless of their areas' contribution to the transmission constraint [4].

2.2 Benefits of Locational Marginal Price

Locational Marginal Price is a market-based means of pricing efficient use of transmission systems when constraints prevent economically priced power from flowing to where it is needed. In the short-term, LMP improves efficiency wholesale of electricity market by ensuring that the cost of congestion reflects electricity prices and ensures that the least-cost supply of electricity is delivered while respecting the physical limitation of the transmission network. In the long term, LMP helps relieve congestion by promoting efficient investment decisions. Because LMP creates price signals that reflect the locational value of electricity, participants can readily determine areas of congestion and will observe the value of investing in generation, transmission and demand response programs. Appropriately located generation additions, transmission and demand response will increase competitiveness of all electrical power markets. Greater access to a larger number of competing suppliers helps to enforce market discipline by not resorting to administratively applied market power remedies. Increased access to energy from lower-cost generators or imported power will ensure robust competitive prices. Also increased competition from strategically located lower-cost units and demand response will benefit much of New England, as the transmission grid is utilized more efficiently. Ultimately, increased competition should result in a more efficient wholesale energy market with lower costs. LMP increases the efficiency of a competitive wholesale energy market and its benefits include [5]:

- The opportunity to hedge congestion costs
- Assurances that power MWs are available at a given time/location

- Greater knowledge of the cost of moving power when traffic on the grid is full
- Confidence in their decision-making
- Reliability of the electric grid (more options for purchasing energy cost-effectively)
- More options for energy producers to find markets for their electricity
- Greater transparency for regulators seeking to ensure reliability and affordability of energy

2.3 LMP Calculation

Unlike the original market in New England, in which there is one energy clearing price, and prices are calculated at three types of locations: the node, load zone and hub. In this type of market offers and bids are submitted, markets settle, and LMP's are calculated at these locations [6]. Nodes represent places on the system where generators inject power or where demand, or load, withdraws from the system. Each pricing node is related to one or more electrical buses on the power grid. A bus is a specific component of the power system at which generators, loads or the transmission system are connected.

All transmission systems experience electrical losses, which occur as electricity is sent over transmission lines and accounts for a small percentage of electricity from generators. Nodal prices are adjusted to account for the marginal cost of losses. If the system was entirely unconstrained and there were no losses, all of the LMP's would be equal and would reflect only the energy price. The lowest possible cost generation could flow to all nodes over the transmission system and generators are paid nodal LMP's.

Listed below are the LMP values at each bus are produced by the linear programming.

$$\min \sum_{i=1}^{N} C_i \cdot P_{gi}$$

Subject to, System power balance constraint:

$$\sum_{i=1}^{N} P_{gi} - P_l - loss = 0$$

Network constraint:

$$\sum_{i=1}^{N} S_{ki} \cdot P_{gi} \leq T_k^{\max}, k = 1, 2, ..., K$$

Generator limit constraint:

$$P_{gi}^{\min} \leq P_{gi} \leq P_{gi}^{\max}, i = 1, 2, ..., N$$

Where:
C_i: Cost or benefit associated with unit production
P_{gi}: Decision variables for generation dispatch of unit i
P_l: Fixed demand
$loss$: Transmission losses
$P_{gi}^{\min}, P_{gi}^{\max}$: Min and max dispatch limit for unit i
$T_k^{\max}$: Grid security limit for constraint k;
S_{ki}: Sensitivity of constraint k with respect to unit i

The Lagrange function of the problem is as follows:

$$L = \sum_{i=1}^{N} C_i \cdot P_{gi} + \sum_{i=1}^{N} \lambda_i (P_{gi} - P_l - loss) + \sum_{i=1}^{N} \mu_{ki} (S_{ki} \cdot P_{gi} - T_k^{\max})$$

So the locational marginal price at node i is given by the formula:

$$\lambda_i = \lambda - LF_i \cdot \lambda + \sum_{k=1}^{K} S_{ki} \cdot \mu_k$$

Where:
λ: System lambda, the shadow price corresponding to the power balance equation
μ_k: Shadow prices corresponding to the constraint k
λ_i: Locational marginal price at node i
LF_i: loss factor at location i

2.4 Congestion vs. a Congestion Free LMP Calculation

When congestion isn't present and power losses are ignored, the LMP are equal in all the buses. If there is congestion in the system, the market divides into two parts: the congested area and the congestion free area. The LMP's in the congested area are higher than those in the congestion free area. On the contrary, in the congestion free area, the LMP's are less. When there is congestion, more generating capacity in the congested area is dispatched in order to meet the load requirement [6]. Owing to the congestion in the network, the generation companies in the congested area have an income increase, while the generation companies in the congestion free area have an income decrease, so the total incomes of all the generation companies increase. Congestion management by LMP results in the market operator's merchandise surplus, which is defined as the difference between the customers purchase costs and the generation companies settlement incomes. Conversely, merchandise surplus is exactly the congested power flows multiplied by its Lagrange multiplier. Owing to congestion, the pre-dispatch plan of the generating units must be changed, and the more expensive units dispatched to supply energy. So congestion causes deadweight welfare loss in the market. The loss in this example is small because the bidding curves of the units are continuous instead of piece-wise and the output adjusting doesn't result in the start or stop of the units. Figure 2.2 shows an example of how a system responds when it is without congestion. The system is composed of five generating units and buses, as well as three loads. There is no congestion present because none of the transmission lines have reached its thermal limit. As a result, the generator named Alta is only one marginal unit and is the one that set the price in all the buses of the system.

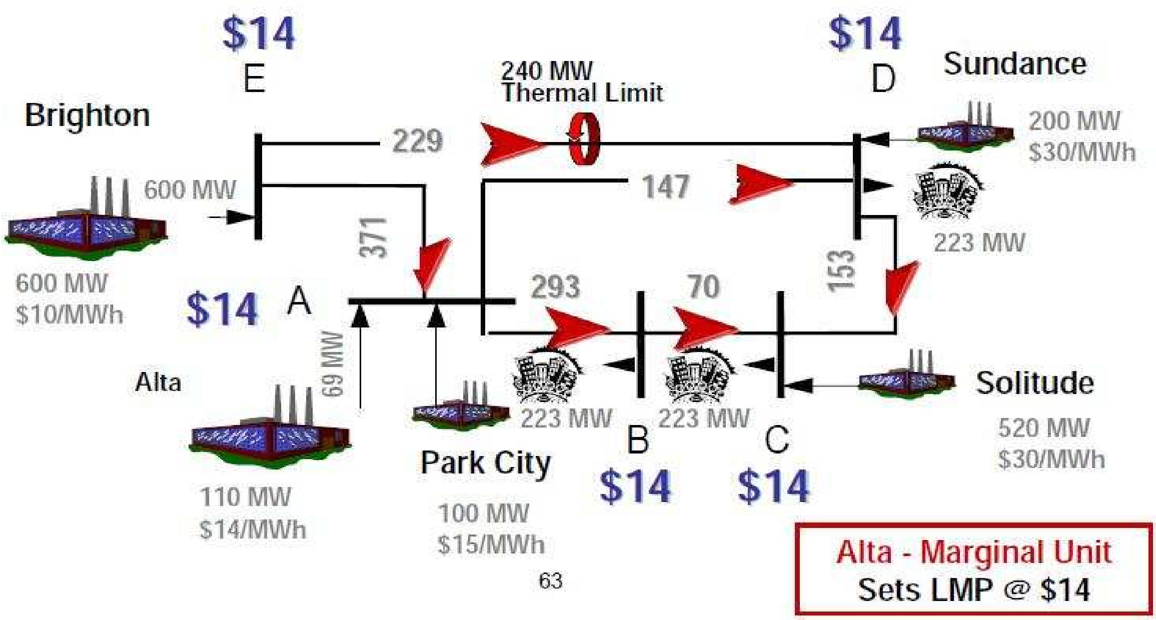


Figure 2.2: LMP on 5-bus system without congestion

If there is congestion, the preferred pre-dispatch plan of the generating units has to be changed so more expensive units in the congested areas are dispatched. In order to meet the requirement of energy supplied to the customers. So the incomes of the generation companies in the congested area increase while the incomes of the generation companies in the congestion free area decrease. The consumers in the congested area have to pay more to purchase their electricity energy, while the consumers in the congestion free area pay less for the energy. More expensive units provide some electricity energy originally offered by cheap units. So the transmission congestion invalidates the optimization of generating resources in the whole network, resulting deadweight welfare loss and debases the market efficiency in power systems. The market operation department should be vigilant to transmission congestion and eliminate congestion through deploying various physical or financial means. In order to optimize generating resources and increase the market efficiency in the whole network. Figure 2.3 shows a system with congestion and how the LMP changes in every location in this situation.

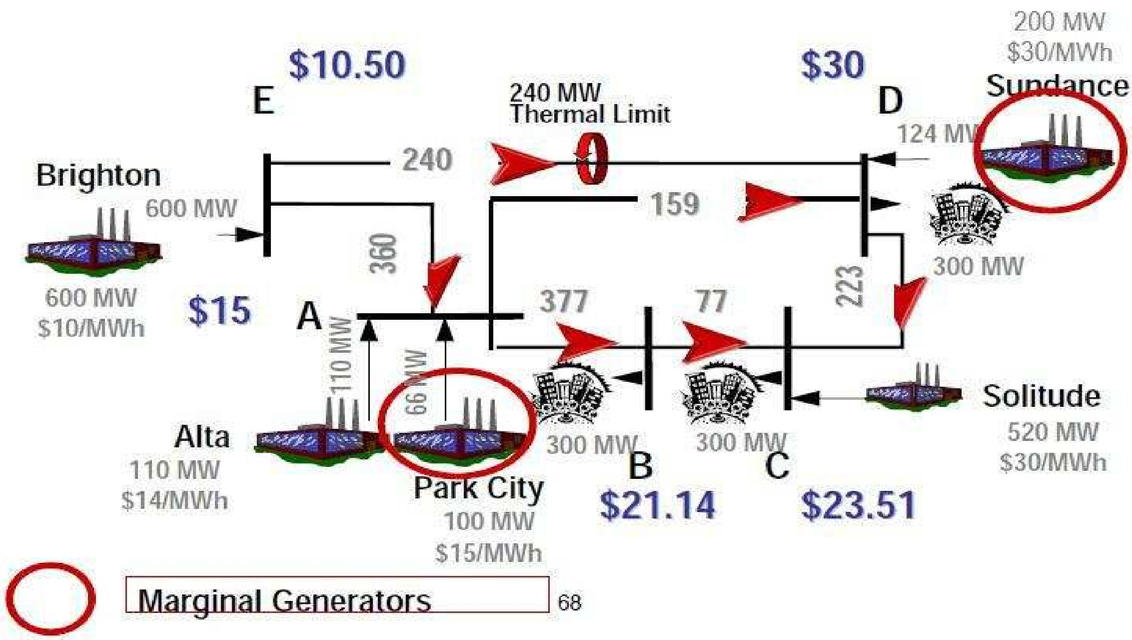


Figure 2.3: LMP on 5-bus system with congestion

3 ELECTRIC POWER MARKETS

3.1 Power Market Models

The development of electricity markets is based on the premise that electrical energy can be treated as a commodity. There are, however, important differences between electrical energy and other commodities such as bushels of wheat, barrels of oil or even cubic meters of gas. These differences have a profound effect on the organization and the rules of electricity markets.

As discussed in the previous chapters, a market is an environment designed to help buyers and sellers interact and agree on transactions. These interactions progressively lead to an equilibrium in which the price clears the market, that is, the supply is equal to the demand. If electrical energy is to be traded according to this free-market ideal, the equilibrium between the production and the consumption of electrical energy should be set through the direct interaction of buyers and sellers [7].

In this ideal market, large consumers and retailers purchase electrical energy from generating companies [7]. Like all rational consumers, an estimate of how much to purchase is needed. To this end, they forecast their consumption or the consumption of their own customers for every market period before entering into contracts. For their part, generators schedule the production of their units, to deliver at the agreed time the energy that they have sold. Each generator clearly tries to minimize the cost of producing this energy. In reality either party can reliably meet its contractual obligations with perfect accuracy. First, the actual demand of a group of consumers is never exactly equal to the value forecasted.

Second, unpredictable problems often prevent generating units from delivering the contracted amount of energy. A sudden mechanical or electrical failure may force a unit to shut down or reduce its output. More mundane problems can delay the synchronization of a unit to the system and hence affect the timing of its production of energy. There are basically two organizational models for the market place of electricity: the bilateral type and the pool one. Ultimately both approaches can theoretically achieve pure competition. Once a fair and efficient spot market is in place, electrical energy can be traded like other commodities. Figure 3.1 shows a schematic diagram of the operation of a spot market. In the next section, we will discuss how this trade can be organized [7].

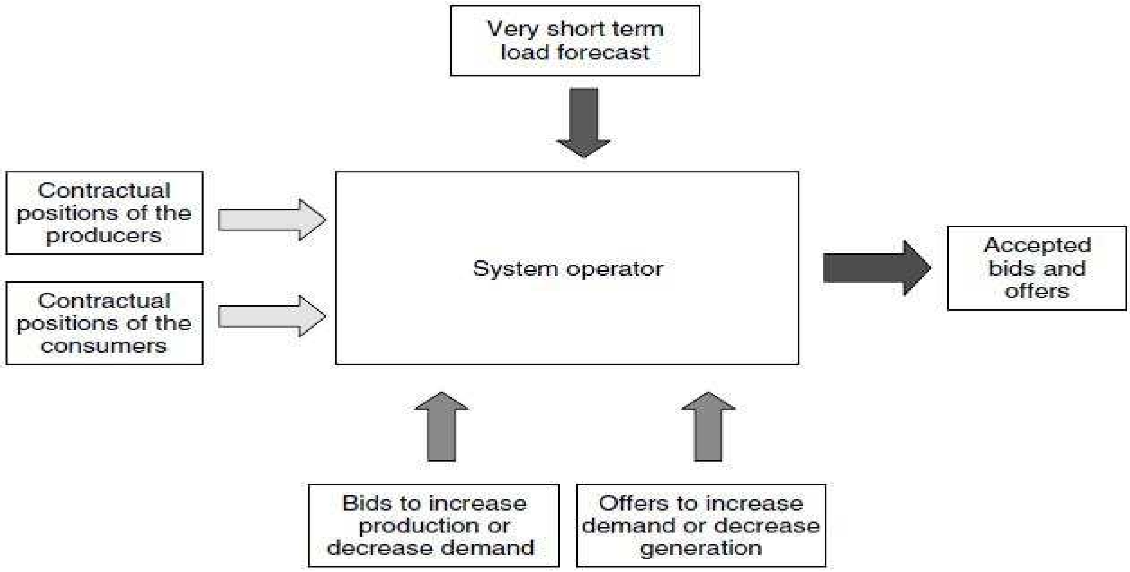


Figure 3.1: Schematic diagram of the operation of a power market

3.2 Bilateral Scheme

This approach is based on party to party transactions without a central broker institution [8]. It is portrayed as the ultimate freedom of choice and access. However, it requires the participation of a middle player named Qualified Scheduling Entity (QSE). QSE submit to the System Operator balanced energy schedules from Load Serving Entities (LSE) and energy required to serve the load. The balance schedules are the result of bilateral transactions. The operator is limited to operate the electricity market when it is required to deal with the energy imbalances that result due to the differences between the real time system requirements and the system loading anticipated in the balanced schedules or when there is no market solution to resolve congestion.

As its name implies, bilateral trading involves only two parties: a buyer and a sell Participants thus enter into contracts without involvement, interference or facilitation from a third party. Depending on the amount of time available and the quantities to be traded, buyers and sellers resort to different forms of bilateral trading:

- **Customized Long term contracts-** The terms of such contracts arc flexible since they are negotiated privately to meet the needs and objectives of both parties. They usually involve the sale of large amounts of power over long periods of time. The large transaction associated with the negotiation of such contracts make them worthwhile only with the parties want to buy or sell large amounts of energy.
- **Trading over the counter-** These transactions involve smaller amounts of energy delivered according to a standard profile, that is, a standardized definition of how much energy should be delivered during different periods of the day and week. This form of trading has much lower transaction costs and is used by producers, consumers to refine their position as delivery time approaches [8].

- **Electronic trading-** Participants can enter offers to buy and bids to sell energy directly in a computerized marketplace. All market participants can observe the quantities and prices submitted but do not know the identity of the party that submitted each bid or offer. When a party enters a new bid, the software that runs the exchange, checks to see if there is a matching offer for the period of delivery of bid. If it finds an offer whose price is greater than or equal to the price of the bid, a deal is automatically struck and the price and quantity are displayed for all participants to see. If no match is found, the new bid is added to the list of outstanding bids and will remain there until a matching offer is made or the bid is withdraw it lapses because the market closes for that period. A similar procedure is used each time a new offer is entered in the system. This form of trading is extremely fast and inexpensive. A flurry of trading activity often takes place in minutes and seconds before closing of the market as generators and retailers fine-tune their positions ahead of the delivery period.

The essential characteristic of these three forms of bilateral trading is that the price of each transaction is set independently by the parties involved. There is, thus no official price. While the details of negotiated long-term contracts are usually private, some independent reporting services usually gather information about over-the-counter trading and publish unidentified summary information about prices and quantities. This type of market reporting and the display of the last transaction enhance the efficiency of the market, by giving all participants a clear idea of the state and the direction of the market.

3.3 Pool Scheme

The pool arrangement comes as a deregulation derivative of the traditional power pool that has existed for many decades in the traditional utility environment; now expanded to include the rest of the market players. It is based on the institutional centralization of the function of bid reception in an auction from the energy players and its management instead of having the trading activity as bilateral. The institution referred to is the independent system operator (ISO) or Regional Transmission Organization (RTO) that also carries the technical power system operation function as well as the exchange one. This pool mechanism is also brought about by special characteristics of the electric power system and the market phenomenon. One of the salient features of this scheme is the price clearing process which is based on the submitted bids by the generation entities and resources to the pool and the ISO selecting the most efficient ones by which in turn makes the proper adjustments to reflect network constraints. In general there is a marginal cost approach that considers marginal losses, marginal maintenance and marginal quality of supply costs, including the grid topology and congestion issues. The generation resource entities sell electricity into a pool, and load serving entities purchase from the same pool within an exchange mechanism where the amount of demand and supply sets market prices for buyers and sellers.

In the early days of the introduction of competition in electrical energy trading, bilateral trading was seen as too big a departure from the existing practice [8]. Since electrical energy is pooled as it flows from the generators to the loads, it was felt that trading might as well be done in a centralized manner and involve all producers and consumers.

Competitive electricity pools were thus created. Pools are a very unusual form of commodity trading but they have well-established roots in the operation of large power systems. In fact, some of the competitive electricity pools currently in operation were developed on the basis of collaborative pools created by monopoly utility companies with adjacent service territories. Rather than relying on repeated interactions between suppliers and consumers reach the market equilibrium, a pool provides a mechanism for determining this equilibrium in a systematic way. While there are many possible variations, a pool essentially operates as follows:

- Generating companies submit bids to supply a certain amount of electrical energy at a certain price for the period under consideration. These bids are ranked in order of increasing price. From this ranking, a curve showing the bid price as a function of the cumulative bid quantity can be built. This curve is deemed to be the supply curve of the market.
- Similarly, the demand curve of the market can be established by asking consumers to submit offers specifying quantity, price and the ranking of these offers in decreasing order of price. Since the demand for electricity is highly inelastic, this step is sometimes omitted and the demand is set at the value determined using a forecast of the load. In other words, the demand curve is assumed to be a vertical line at the value of the load forecast.
- The intersection of these constructed supply and demand curves represents the market equilibrium. All the bids submitted at a price lower than or equal to the market

clearing price are accepted and generators are instructed to produce the amount of energy corresponding to their accepted bids. Similarly, all the offers submitted at a price greater than or equal to the market clearing price are accepted and the consumers are informed of the amount of energy that they are allowed to draw from the system.

- The market clearing price represents the price of one additional megawatt-hour of energy and is therefore called the system marginal price (SMP). Generators are paid this SMP for every megawatt-hour that they produce, whereas consumers pay the SMP for every megawatt-hour that they consume, irrespective of the bids and offers that they submitted. Paying the SMP for all the generation that was accepted may appear surprising at first glance.

3.4 Model Comparison

It is possible to make a general comparison between the two basic schemes by pointing strengths and weaknesses. This type of comparison is presented in the following page.

Some of these attributes shown may be either discussed or challenged. For a small generic player the trading advantages claimed for the latter scheme are offset by the exposures to both Congestion Management and Ancillary Services (A/S). In contrast the affiliate utility posses a self-serving territorial A/S capability enhanced and smoothed by its diversity, under these conditions it has little exposure but both substantial market power and a competitive advantage. Moreover, the attainment of pure competition is based on the exhaustive participant market search, which becomes severely limited, under bilateral conditions, for the non-utility affiliate due to counter party risk. This is avoided in the pool structure. The lack of pricing information for primary energy is a distinct disadvantage of the bilateral model for the small or medium player, even though incremental bids may be required for ancillary/balancing services and congestion management. The lack of a primary spot price renders these secondary markets potentially volatile and risky for non-utility players. In both models the ISO remains as the only monopoly which raises a number of questions. First the non profit statute given to this organization seems to be followed by a unwarranted non-risk benefit; secondly lies the supervision to the ISO as a complex issue. There is no clear incentive to make the ISO perform in an optimal manner. The system operator has a decisive role to play in the critical A/S, but it must have the right structure, ways and means [9]. The strength and weakness of both models are shown below.

	STRENGTH	WEAKNESS
POOL	Spot Price Easy Trading Transparency Congestion Management No Counterparty Risk	ISO Monopoly Power Ex-post Settlements Complexity
BILATERAL	Trading Freedom Trading Privacy	No Explicit Market Price Counterparty Risk Congestion Management Ancillary-Service Exposure

Table 3.1: Market Model Comparison

Since both the pool and the bilateral models of electrical energy trading have been adopted for electricity markets, it is valuable to review perceived advantages and disadvantages of both approaches.

As mentioned above, a competitive electricity pool is often created on the basis of an existing cooperation agreement between various utilities. Its conversion to operation on a competitive basis will therefore be less of a revolution than the creation of a completely new structure. Some of the concerns that accompany the introduction of competition may be alleviated by the less radical nature of change. In particular, the public and the government are likely to have fewer concerns about the security of the electricity supply if the same organization remain in charge. A pool provides a much more centralized form of system management. Not only does it handle all the physical electrical energy transactions, but it usually also assumes the responsibility for operating the transmission system. This combination of roles avoids the multiplication of organizations but makes it more difficult to distinguish between the various functions that need to be performed in an electricity market.

Most small and medium electricity consumers have very little incentive to take an active part in an electricity market. Even when they are aggregated, the retailer that represents them has no direct means of adjusting consumption in response to changes. Therefore argue that the transaction costs could be reduced significantly if the demand is deemed to be passive and is represented by a load forecast in an electricity pool. Many economists are unhappy with this approach because they feel that direct negotiations between consumers and producers are essential if efficient prices are to be reached. These economists dislike pools because they are only administered approximations of a market [9].

Pools also provide a mechanism to reduce the scheduling risk faced by generators and hence, the cost of electrical energy. When a generator sells energy for each market period separately on the basis of simple bids, it runs the risk not to sell enough energy to keep the plant on-line. At that point, it must decide whether to sell energy at a loss, or to shut it down and face the expense of another start-up. Either option increases the cost of producing energy with this unit and forces the generator to raise its average bid price. If this generator trades in a pool that operates on the basis of complex bids, the rules of this pool probably ensure to recover the start-up and no-load components of its bid. Moreover, the scheduling algorithm implemented by the pool usually tries to avoid unnecessary shutdowns.

3.5 Main Market Implementations

There are three outstanding market implementations in the US; these schemes are structurally distinct; they are the Pennsylvania, New Jersey, Maryland (PJM), California Independent System Operator (CAISO), and the evolving Electric Reliability Council of Texas (ERCOT) [9]. In the PJM's case, both New Jersey and Maryland member states have been deregulated in electricity while Pennsylvania has not yet reached that status completely. Nevertheless, the PJM has been a very effective pool operation for over four decades stemming from the period of the traditional utility structure. California has gone into a full-scale deregulation while its neighboring states in the Western System Coordinating Council (WSCC) region have not yet embarked on that process. The system has two major interconnecting market hubs: the northern California Oregon Border (COB) that ties to hydro resources and the southern Palo Verde hub which ties predominantly to fossil fuel and nuclear generation. It also interconnects with Tijuana, Mexico, via San Diego and with Las Rositas, Mexico, via the Imperial Valley station. Finally, Texas fully reached a deregulated status by January 2002 under ERCOT power system operational guidelines in a process termed Texas Choice.

Figure 3.2: National overview of electric power markets

With the introduction of competition, wholesale power trading has increased markedly. An example is the substantial increase of power marketers in the United States. Power marketers buy and sell electricity, but they do not own or operate transmission or distribution facilities. Currently, over 500 companies are classified as power marketers and have filed rate tariffs with the FERC to sell wholesale power in the United States. However, actual sales by power marketers are concentrated in approximately 50 companies or less [9].

4 CONTROLLABLE LINE PRICING

4.1 Overview

This chapter discusses the circumstances in which power scheduled to flow over a controllable line from a particular source would be priced differently than power delivered from that same source but over free-flowing lines. There are two principal factors that affect pricing of energy scheduled to flow over controllable lines, relative to the price of energy delivered from the same source over free-flowing ties. The first factor is whether the scheduling of the controllable line is determined by the ISO as part of its overall economic dispatch or is determined by another entity and provided to the ISO. The second factor is whether the outage of the controllable line is one of the binding contingencies in the ISOs security analysis.

If the schedules for the controllable line are determined by the ISO as part of its overall economic dispatch, then the pattern of flows over the controllable line and other lines are not a result of market participant decisions and all schedules for net injections and withdrawals at given receipt and delivery points would be identically priced. The ISO could in these circumstances collects congestion rents for flows scheduled over the controllable line flow over the AC interconnects. Depending on the compensation arrangements relating to the transfer of control of the controllable line to the ISO, this compensation might require calculation price. If, on the contrary, schedules over the controllable line were determined by individual market participants, then it would be desirable that pricing of those schedules provide market participants with effective incentives.

The other key factor influencing the pricing of energy scheduled to flow over controllable lines is whether the outage of the controllable line is a binding contingency in the ISOs security analysis. In the circumstance in which the outage of the controllable line is the only binding transmission constraint and contingency, then the total level of transfers does not depend on the schedules over the controllable line. Instead, the total level of transfers is determined by the pattern of transmission flows in the contingency in which flows over the controllable line are zero. In this circumstance as incremental variations in the pre-contingency schedules over the controllable line do not affect the cost of meeting load demand. It still could be the case that the operation of the controllable line increases total transfer capability and thus contributes to congestion rents. If the outage of the controllable line were not the binding contingency or were not the only binding constraint or contingency, then the total level of transfers and production costs would depend on the amount of energy scheduled to flow on the controllable line and optimal scheduling of flows on the controllable line would require a distinct price signal for those schedules. In these circumstances the value of energy delivered over the controllable line could, in principle, range from being equal to the value of power delivered over the AC interconnect to having a value greater than that of energy injected by a generator at the delivery point of the controllable line.

In the circumstances in which flows over a controllable line are not determined by the ISO, efficient scheduling incentives can be provided to market participants by establishing separate prices for injections scheduled to flow over the controllable line and over the open ties. In the circumstance in which the controllable line connects separate control areas, interchange between the control areas is limited by constraints affected by delivery over the open ties, and outage of the controllable line is not a binding contingency. The proxy bus prices for energy delivered into the receiving control area over the controllable line would be different and higher than the proxy bus price for energy delivered into the receiving control area over the open ties. Similarly, the charge for transmission service for power delivered to a given location within the receiving control area would be lower for transmission service scheduled over the controllable line than for transmission service priced off the proxy bus for the open ties. The circumstances in which the outage of the controllable line is not a binding contingency does not necessarily imply that the controllable line would be operated optimally. It just means that the controllable line has not been designed to such a large capacity that its outage becomes a new binding constraint in the reliable operation of the control area.

The same pricing system would be used to settle financial transmission rights for the controllable line. In particular, financial transmission rights for the controllable line would be defined from the proxy bus for the controllable line to a point of delivery within the receiving control area. In the circumstance in which the delivery of power over the controllable line is limited by congestion, for example, if the outage of the controllable line were the binding contingency, then the proxy bus price for power scheduled to be delivered and the holder of the financial transmission right would receive a congestion payment. In the circumstance in which deliveries over the controllable line are not limited by congestion, the proxy bus price for power scheduled to flow over the controllable line would be high relative to the price at the point of delivery and the financial transmission right would have little or no value, but there would be a large incentive to schedule power to flow over the controllable line. Finally, in the circumstances in which the controllable line is not available or no power is scheduled to flow over the line, the financial transmission rights awarded in conjunction with the controllable line would have no value.

4.2 Pricing

The pricing of energy delivered from or to external control areas can be formulated in terms of the fundamental LMP pricing equation:

$$P_i = (1 + L_i) P_{ref} + \sum_j \sum_k SP_{jk} SF_{jki}$$

Where:

P_i= Locational price at bus i

L_i=Marginal loss factor at bus i

P_{ref}=Locational price at reference bus

SP_{jk}=Shadow price of constraint j in contingency k

SF_{jki}=Shift factor for real load at Bus i on constraint j, in contingency k

The special consideration in applying the LMP pricing equation to deliveries over controllable lines is that energy scheduled to flow over a controllable line would be priced as distinct injection and delivery point. An example is when an energy schedule to flow over a controllable line would be modeled distinctly from energy injected by generation at the point of delivery from the controllable line and distinctly from power injected at the source of the controllable line and delivered over free-flowing ties. Distinct prices would be calculated for deliveries of energy over a controllable line to a bus and from a generator at that bus, and the prices could differ, depending on the binding constraints and contingencies. In circumstances in which the proxy bus price for energy scheduled to flow over the controllable line was lower than the price at the delivery point of the controllable line, there would be a congestion charge for deliveries scheduled over the controllable line. If the proxy bus price for energy scheduled to flow over the controllable line was equal to the price at the delivery point of the controllable line, there would be no congestion charge for deliveries scheduled over the controllable line.

The proxy bus price for energy injected at a given point and scheduled to flow over a controllable line would be distinct from the proxy bus price for energy injected at the same point but flowing over open ties. Thus, in circumstances in which there was transmission congestion limiting deliveries over the open ties but not over the controllable line, the price of energy delivered over the controllable line could be higher and the congestion charge lower than for energy delivered over the open ties.

In general, the price of energy delivered over a controllable line would be greater than or equal to the price of power generated at the point of delivery and could be higher than the price of energy injected at the source of the controllable line but flowing over the open ties if the outage of the controllable line were not a binding contingency. If the outage of the controllable line were the only binding contingency, then price of energy delivered over the controllable line would be less than the price of power delivered from a generator at the delivery point and less than or equal to the price of energy injected at the source of the controllable line were one of two or more binding contingencies, the price of power delivered over the controllable line could be less than or greater than the price of power delivered from a generator at the delivery point.

These pricing principles are illustrated in the examples below. It is convenient to begin with the situation in which the outage of the controllable line is not a binding contingency and then consider the more complicated case in which the outage of the controllable line is one of the binding contingencies. For simplicity, the examples are set up from the standpoint of the pricing by the controllable area that receives deliveries of energy over the controllable line, and the only transmission constraint in the example is located within this control area. The LMP pricing equation would also govern the pricing of energy withdrawn over the open ties and the controllable line, depending on the effect of these flows on transmission constraints within the delivering control area. The transmission pricing system for controllable lines described can be implemented independently of a combined day-ahead market. Some of the current problems pertaining to the availability of inter-control area transfer capability in real-time and real-time curtailments could be alleviated by a pricing system for controllable lines that provides appropriate scheduling and operating incentives. Conversely, however if a combined day-ahead market were implemented but the pricing and operation of controllable lines were left unchanged, then some of the current curtailment and scheduling problems might persist.

The first example illustrates a situation in which the increased deliveries of energy over the controllable line would reduce the costs of the receiving control area [10]. It is initially assumed that bus 5 is the receiving control area and thus that lines 6-5, 2-5 and 7-5 are inter-control area ties, as illustrated in the figure below. Bus 3 is the reference bus in the sending control area that is used operationally by the receiving control area for modeling the source of imports. Line 7-5 is the controllable line. Figure 4.1 portrays the pre-contingency flows. It is seen that there are neither binding pre-contingency transmission constraints nor losses.

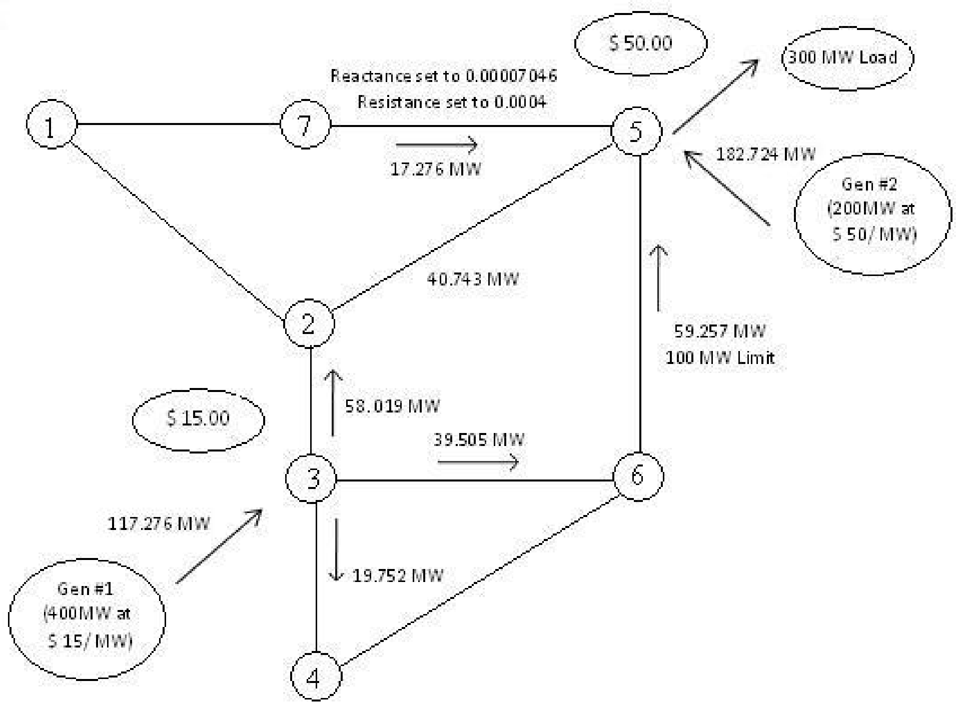


Figure 4.1: Pricing with no outage

Figure 4.2 portrays the flows following the outage of the controllable line 7-5. It is seen that the post-contingency flows on the line 6-5 are well below the 100MW limit and thus that the outage of the controllable line is not a binding contingency and does not limit the level of imports into control area 5 from generation at bus 3.

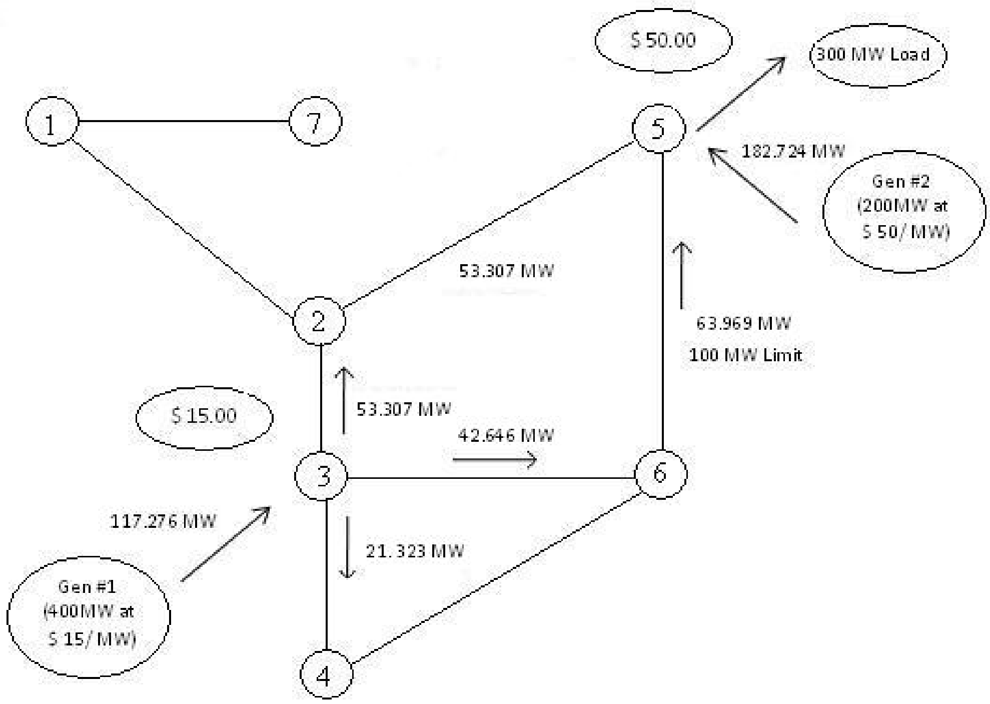


Figure 4.2: Pricing with line 5-7 outage

Finally, figure 4.3 portrays the flows following the outage of the line 2-5. It can be seen that the post-contingency flows over the line 6-5 are at the limit. In this example, we have assumed that the flows on the controllable line are fixed in the contingency and thus that post-contingency flows over the controllable line are unchanged. Because the post-contingency flows over 6-5 are a binding constraint on injections at bus 3, no additional imports could be scheduled from bus 3, given the settings on the controllable line. In this situation, the price of power at bus 3 is set by the bid of the marginal generator at that location and would be $15 in the first example.

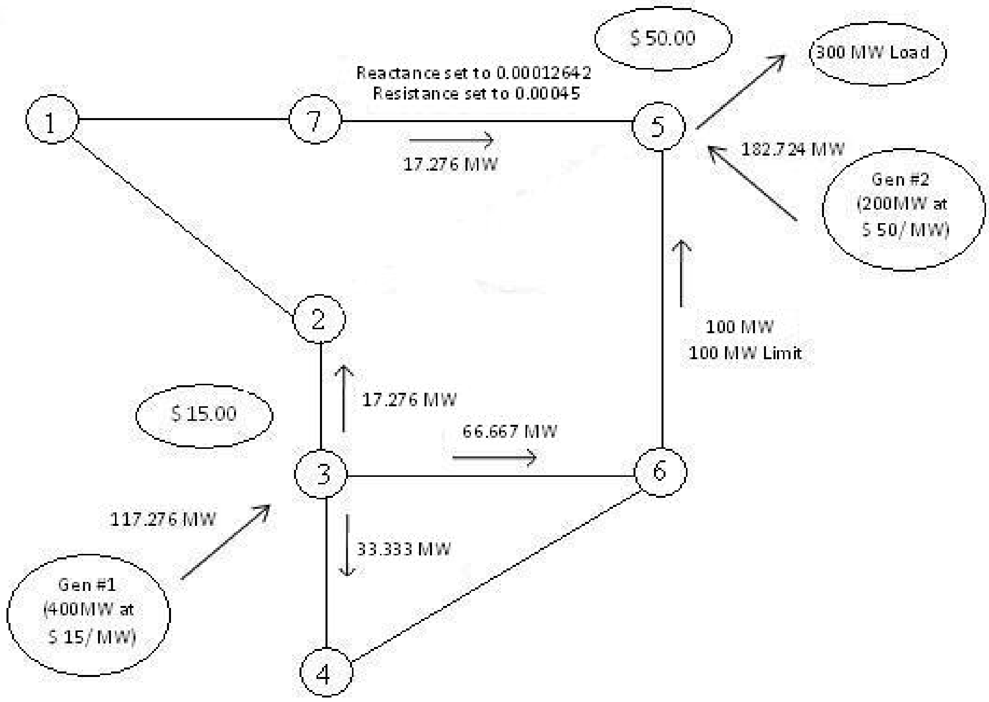


Figure 4.3: Pricing with line 2-5 outage

In the situation described by this scenario, in which transfers into the control area at bus 5 are limited by the post-contingency flows over the line 6-5, increased pre-contingency schedules over the line 7-5 would increase total transfers into the control area at bus 5. The lower the resistance and reactance set on the line 7-5, the higher the pre- and post contingency flows on line 7-5 and thus the higher the total transfers into the control area at bus 5. This can be illustrated by considering the impact of a reduction in the resistance and reactance of line 7-5 sufficient to increase pre-contingency flow over this line by 1 MW. These pre-contingency flows are portrayed in the following figure.

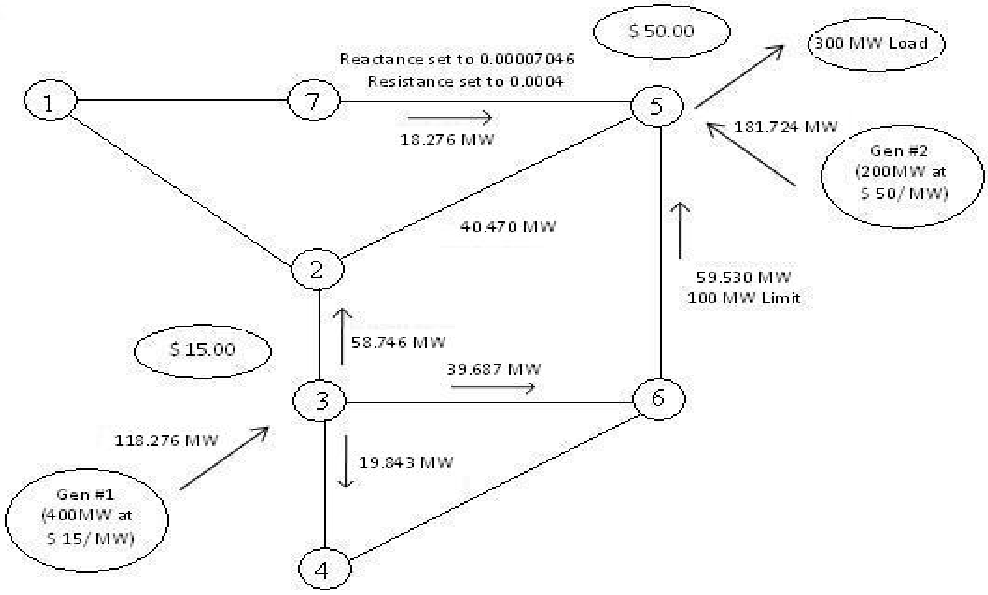


Figure 4.4: New pricing with no outage

It can be further seen that the outage of the line 7-5 is not a binding contingency, following the increase in flows scheduled on line 7-5, see figure 4.5.

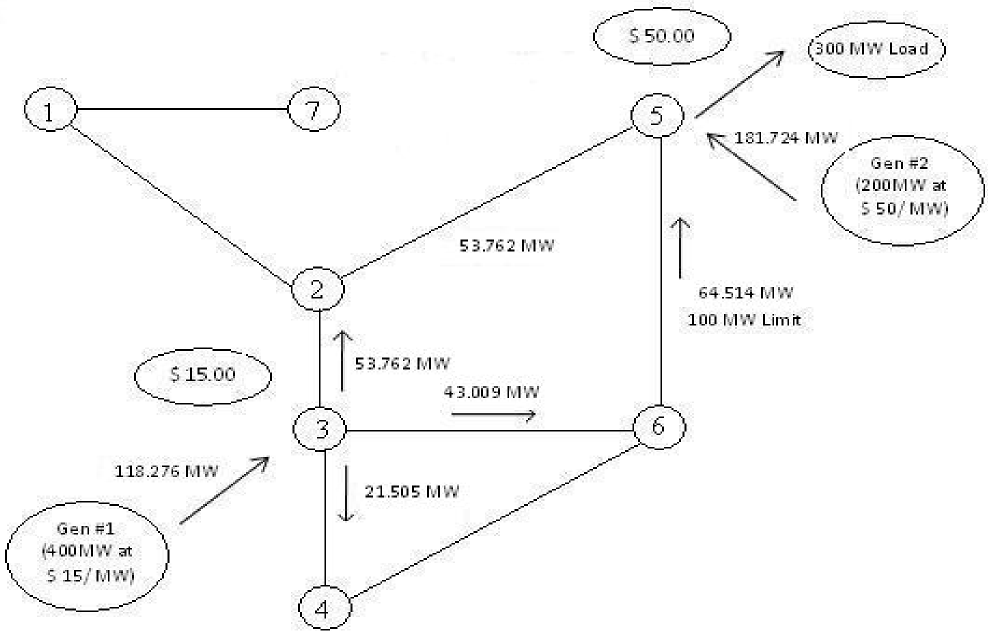


Figure 4.5: New pricing with line 5-7 removed

Finally, figure 4.6 portrays the flows following the outage of the line 2-5, which is the binding contingency, and it is seen that the post-contingency limit on flows over line 6-5 is not violated. As before, it is assumed that flows on the controllable line are held fixed in the contingency. By comparing the first and fourth figures, it can be seen that a 1 MW increase in flows over the line 7-5 leads to a 1 MW reduction in generation at 5 and thus to a $50 reduction in the as-bid production cost within control area 5, without violating the post-contingency limit on flows over line 6-5. The value of a MW of power delivered over the controllable line 7-5 is therefore $50 per MW, the change in the cost of meeting load at 5 by increasing deliveries over line 7-5. In particular, it is important to note that scheduling of an additional MW over the controllable line does not reduce scheduled transfers over the AC interconnects, but leads to an increase in the total transfers. Thus, as long as the post-contingency flows on the line 7-5 were as large as the pre-contingency flows, an increase in pre-contingency schedules on the controllable line would increase total deliveries at bus 5 by 1 MW and thus the appropriate proxy bus price for deliveries over the controllable line would be the bus 5 price.

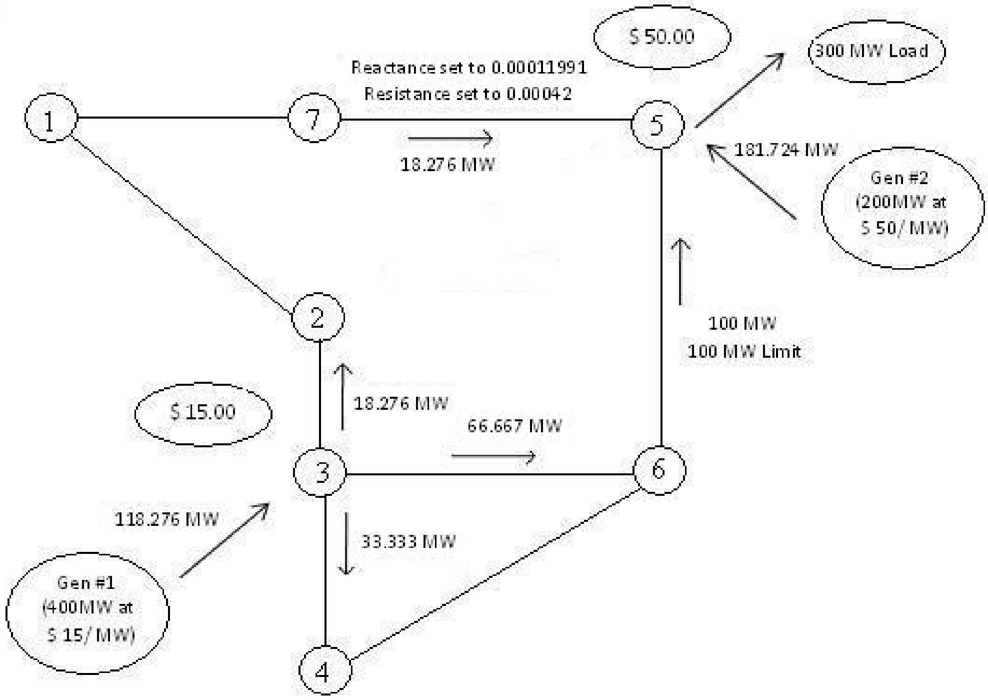


Figure 4.6: New pricing with line 2-5 removed

The schedules over the line 7-5 appear to be in disequilibrium at the prices at bus 3 and 5 in this scenario as incremental schedules on the controllable line would be profitable. The schedules shown would, provide equilibrium if there were a pre-contingency limits on flows over the controllable line of 17.276 MW, either to avoid overloading the line 7-5 or to avoid overloading lines 2-1 or 1-7. In this case, prices and schedules would be as shown, but no entity would be able to increase schedules over the controllable line. Alternatively, the line 7-5 could be a DC line with operating costs. The schedules shown in this scenario would also be in equilibrium if the charge for scheduling power over the controllable line were $35/MWh.

4.3 LMP Calculation using Controllable Lines

The use of controllable lines offers different approaches for modeling the network and treating control parameters and the degree of control. In the case of controllable lines that can maintain flow during a contingency, there is a natural interpretation of the equivalent effect of the controllable line as to create fixed net loads at each end of the line and remove the representation of the line in the network model.

The linearized DC-load approximation illustrates the basic structure of the network pricing results. These could be extended to include changing grid conditions or nonlinear effects. The basic variables are defined as:

d: the vector of bus loads
g: the vector of bus generation
y: the vector of net bus loads
z: the vector of line flows
φ: the vector of bus angles
A: the incidence matrix of lines and buses

Hence the flows on the lines are determined by the difference in bus angles at the ends of the line [11]. Total flows in and out of a bus must equal the net loads. Here the constraints are shown as upper bounds on lines. This is notational convenience, and there is no difficulty including lower bounds or aggregate interface constraints. For computational purposes, it is convenient to include the explicit representation of the angles are included. However, the Schweppe theorem eliminates the angles and produces a representation that relates the net bus loads and line flows [11]. Under the usual assumptions regarding the arbitrary swing bus where the angle is constrained to zero, for convenience here selected to be the last bus, we let A be the incidence matrix with the last column deleted. Hence (AΩA) is invertible. Further let the vector 1 be a column of ones to add up all the net loads in balancing equation. Then we have the equivalent DC-load model:

$$d - g = y$$

$$1^t y = 0$$

$$z = [\Omega A(A\Omega A)^{-1}\ \ 0]y$$

$$z \leq z\max$$

The matrix SF=[ΩA(AΩA)$^{-1}$ 0] is the set of shift factors that can be interpreted as the marginal change in line flows induced by a marginal change in net bus load balanced at the swing bus. To incorporate the controllable line in this model, and introduce contingencies at the same time, distinguish between the normal free flowing (AC) lines and the controllable lines (DC) with some device such as a phase angle regulator or a DC transformer that is able to fix flows. Each contingency yields a different set of parameters. For example, if a line is out, the corresponding row of the incidence matrix is set to zero [12].

One approach to modeling controllable lines would be to treat the respective elements of Ω as variables and adjust them to achieve the intended flow on the controllable lines for the given angle differences. The equivalent alternative used here is to model the controllable flows directly as variables independent of the bus angles. This latter approach produces the same results but makes the pricing equation more transparent.

Here the angles and network loop flow conditions apply only to the free flowing lines. The free-flowing line flows can be different in every contingency, but controllable line flows are assumed to be the same [13]. The loss of the controllable line removes the effect of these flows by zeroing out the corresponding row in the incidence matrix. If is followed the same development as the Schweppe theorem, we get the set of contingency constraints and flows as in: With these constraints, an optimal dispatch problem with benefit (B) and cost (C) can be formulated as:

$$\underset{d,g,y,z_{ac}^{i},z_{dc}}{Max} \quad B(d) - C(g)$$

s.t.

$$\begin{array}{ll}
d - g = y & \lambda \\
1^{t} y = 0 & p_{swing} \\
z_{ac}^{i} = SF_{ac}^{i}\left[y - A_{dc}^{i^{t}} z_{dc} \right], \forall i & \varphi_{ac}^{i} \\
z_{ac}^{i} \leq z\max_{ac}^{i}, \forall i & \mu_{ac}^{i} \\
z_{dc} \leq z\max_{dc} & \mu_{dc}
\end{array}$$

With this formulation we have the associated locational prices (p) determined form the first order optimality conditions as:

$$p = \nabla B = \nabla C = \lambda$$

$$\lambda = p_{swing}1 + \sum_i SF_{ac}^{i^t}\varphi_{ac}^i$$
$$\varphi_{ac}^i = \mu_{ac}^i$$
$$\sum_i A_{dc}^i SF_{ac}^{i^t}\varphi_{ac}^i = \mu_{dc}$$

If intermediate shadow prices are eliminated, it's obtained the usual pricing equations for the marginal effects on the AC network based on the shadow prices for the binding constraints. The connection to the shadow prices on the limits for the controllable line can also be seen.

$$p = \nabla B = \nabla C = p_{swing}1 + \sum_i SF_{ac}^{i^t}\varphi_{ac}^i$$
$$\sum_i A_{dc}^i SF_{ac}^{i^t}\mu_{ac}^i = \mu_{dc}$$

In what can be viewed as an application of the envelope theorem, or the superposition property of the DC-load approximation, is found the locational pricing equation as the same format as the case with the controllable lines removed. In effect, given the optimal solution, the controllable lines could be modeled in the DC-load formulation as fixed net loads at each end of the line. The price of the limit on the controllable line is the contribution to the difference in the locational prices at either end for all the contingencies in which the controllable line is in service. Note that in the case of the controllable line being out of service, the corresponding elements of the incidence matrix are zero and there is no contribution to the prices. Unlike the case for free flowing lines, if the controllable line outage is not a binding contingency, then either the controllable line constraint is binding or the prices are equal at both ends of the line.

5 CASE STUDY

5.1 System Description

This section describes the 5 bus system implemented to study the impact of controllable lines have on locational marginal price. Before finding the best system case-model to study, an intense review of literature was done related to the topic. After careful consideration of all the alternatives, the idea and data used to simulate the system using the software Power World was originally taken from the ISO-NE site in the end. There were several reasons involved for choosing this model over others seen. The first reason was that it wasn’t a big system which might have complicated the analysis of LMP calculations by taking into consideration all the contingencies in the system. The second reason for choosing this system was that it was one used previously by ISO-NE, which is a very recognized electric power market. Finally, the third reason was that it had all the basic data needed to facilitate the implementation of this system on the software used [14].

The transmission system model consists of several different elements necessary to successfully complete its construction. The elements needed are: generators, transmission lines, buses and loads. For the generators, the data needed to adjust was the maximum MW output as well as the cost model. For this case the piece-wise cost model was chosen over the cubic cost model. The piece-wise cost model gives a more accurate representation of how the actual market works in real life. Also, the total generation in the system has to be such that it can be able to supply all the loads in the system. For the transmission lines the parameters needed were the reactance and active power limit of the line. The active power limit for each line was given for each line, and precautions were taken to not overcharge or undercharge the lines. Thus balancing the two options had to be done. For the buses, we had to make sure that the voltage and angle for each one in specific made sense or were justified. For example, it is not recommendable to have angles that are high because that can cause a problem of stability in the system. A slack bus also had to be chosen in the system because it is the one responsible for balancing powers in the system and also absorbing all the uncertainties or loses in the system. Finally, a model for each of the loads in the system had to be chosen as well as its capacity (MW and MVAR values). For this case the model of constant power was used to represent each of the loads in the system to maintain consistency in the model and not complicate it much. The total load capacity of the system was originally defined to have a value of 689 MW. The power system operates at a frequency of 60 Hz and 138 kV nominal in the side of the transmission lines. Figure 5.1 shows the original model or base-case model of the system under study, with each of the initial values given. The values were taken into consideration by the recommendations given by the ISO-NE electric power market site [7].

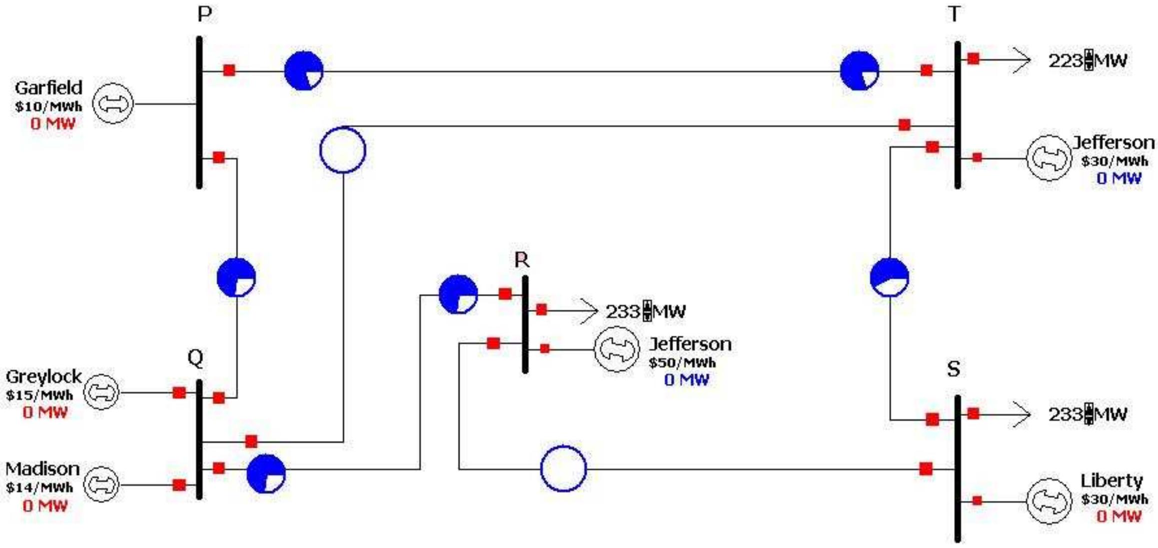


Figure 5.1: Original 5-bus system model

Before completing the model for the case study, a few modifications had to be made to ensure that the model would respond correctly. The first modification was to add a series capacitor to the line Q-T in the system. The reason for this decision was based on the system original state that had some lines overcharged and others undercharged. This allowed power flow in the system to be redistributed better. Thus achieving, a better balance in the system was being looked at. The second change done was to increase the power values in all the loads in the system by at least ten percent. The reason for this change was that without it, several generators were still not dispatching energy into the system and the study needed to incorporate as many generators as possible into the analysis. Another modification done into the model was to reduce the maximum limit of power in some of the generators that were originally dispatching energy into the system. This modification was done because some of the generators with high biding prices were not being taken into consideration in the simulation. In other words, the least cost generator supplied too much power into the system and as a result, it was not making the system practical. The purpose was also to have generators close to a specific location supply to it and not necessarily from the least cost generator because it might cause losses in the system. For example, the generator connected to bus P named Garfield was reduced from 600 MW to 500 MW. Finally, another series capacitor was connected in the transmission line R-S. This was done because this specific line is the one going to make the function of the controllable line when used in the final case of the study to see its impact on the LMP. It was considered at first to connect a phase shifter to the line instead of a series capacitor but was removed because its model did not help what the study tried to do. In other words, its internal reactance wasn't changing as we were trying to modify the parameters in it. Initially, the value of negative reactance for the series capacitor was set to an initial value because to analyze how the system responds without the controllable line and without contingency. Later on, the value is adjusted when dealing when the with the controllable lines aspect of the case.

Figure 5.2 shows the original system model that was modified to improve the model for the studies about to be done afterwards. As a result, this model became the final system version that was modeled for our purposes. Finally, an optimal power flow solution will be shown later in the chapter.

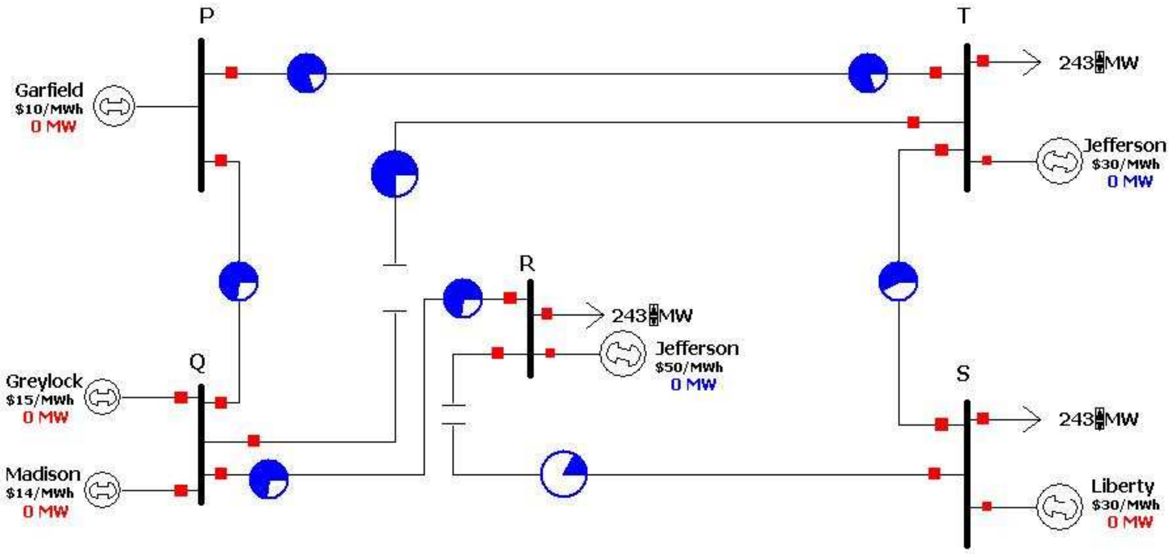


Figure 5.2: Modified 5-bus system Model

Figure 5.2 shows the system composed of five buses that are named by the letters P, Q, R, S and T operating at a nominal voltage of 138kV. In addition, the system has six generators named Garfield, Greylock, Madison, Liberty, Jefferson and Jefferson I. All of the buses have at least one generator connected to it except bus Q which has two generators connected to it. There are three loads in the systems which are connected to the buses R, S, and T. All of the models of the loads are still constant power and have a capacity of 243 MW. Almost all of the transmission lines are at more than half of there maximum capacity. All of the lines are also modeled as purely inductive ones.

Table 5.1 illustrates all of the data in tables of the system modeled for this project. It is separated in two parts; data of the lines in base of 100 MVA and 138 kV and data of the generator and loads. Table 5.2 shows the optimal power flow solution to the case trying to be solved.

From bus	To bus	R(pu)	X(pu)
P	T	0.000	0.0597
P	Q	0.000	0.0164
Q	T	0.000	0.3040
Q	R	0.000	0.2810
R	S	0.000	0.0108
T	S	0.000	0.0297

Table 5.1: Data of lines in base 100MVA and 138kV

Bus Records

	Number	Name	Area Name	PU Volt	Volt (kV)	Angle (Deg)	Load MW	Load Mvar	Gen MW	Gen Mvar
1	1	Q	1	1.00001	138.001	9.60			210.00	27.41
2	2	R	1	0.99998	137.998	4.86	244.00	0.00	0.00	13.32
3	3	S	1	0.99999	137.999	2.99	243.00	0.00	19.98	5.75
4	4	T	1	0.99998	137.997	5.93	243.00	0.00	0.00	22.44
5	5	P	1	1.00000	138.000	12.50			500.00	18.76

Table 5.2: Optimal Power Flow Solution for modified case without contingencies

5.2 System Simulation without Congestion

The first case that ran with the 5-bus system implemented in Power World was the system in its original form. As can be seen from figure 5.3, when there is no congestion and there are no power losses or they are ignored because they did not provide too much impact into the system, the LMP's are equal in all the buses. It can also be seen from the figure that in an area in a system that is considered a congestion-free location the LMP's are less. The reason for this is because when a system is subject to congestion or contingencies, more generating capacity in the congested area is dispatched in order to meet the load requirements, making the LMP higher as a result.

Another observation is that a large amount of power is flowing through most of the transmission lines in the system to meet the demand needed to point where they are almost overcharged. As a result, most of the lines have more than half of the power limit flowing through them. The losses in this case are not showed because the bidding curves of the units are piece-wise instead of continuous and the output adjusting doesn't result in the start or stop of the units.

For this case, the system has four of six generators dispatching energy at the moment. Of those four, three of them are dispatching energy at the maximum and only one of them is neither at the maximum or minimum. This generator is the one connected to bus S that is named Liberty. This generator is supplies energy into the system at 30 $/MWh.

In this case the LMP is set by the only marginal unit in the system that is named Liberty. This is known because of the n+1 rule that states that for n binding constraints, there is at least n+1 marginal unit`s. This does not include equality constraint. In the case of no congestion, there is only one marginal unit and the price at the location of each marginal unit is always equal to its offer price. As a result this makes that the marginal price in all the locations in the system equal to 30 $/MWh. Finally, figure 5.3 also shows how the system responds when it is congestion free the optimal power flow solution and the prices at each of the five buses.

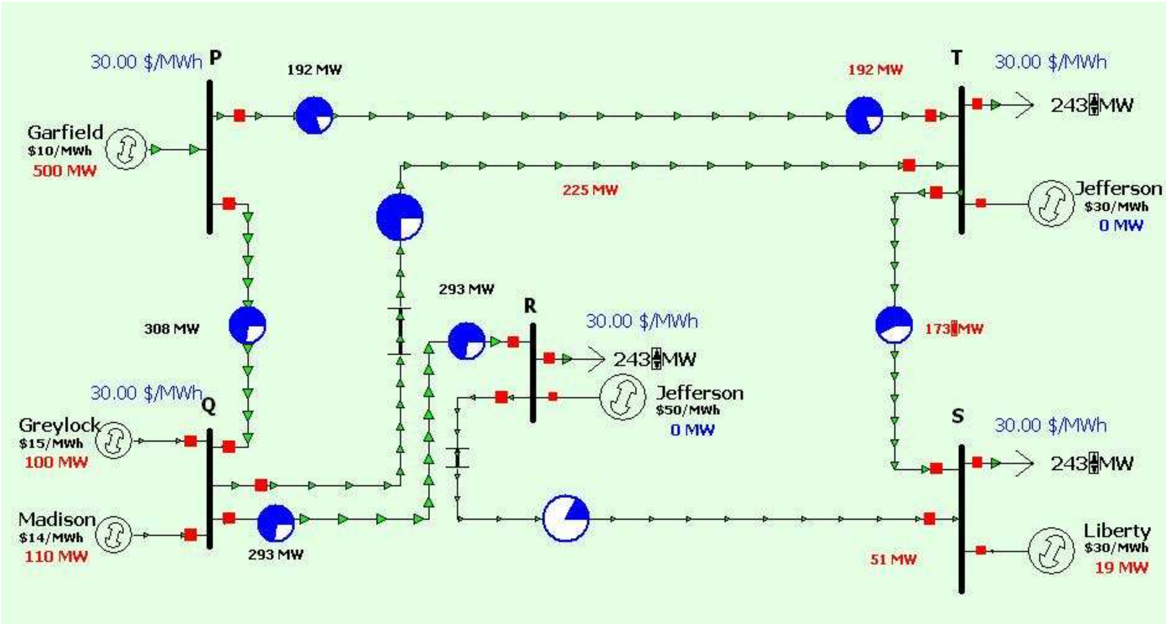


Figure 5.3: 5-bus system model without congestion

5.3 System Simulation with Single Contingencies

The second case studied with the power system simulation was the system with single contingency on line P-T. For this study it was assumed that the breakers opened and the line was removed from the system. As can be seen from the following figure, when there is a contingency in the system, the LMP's are not equal in all the buses.

Figure 5.4 shows that most of the LMP prices stayed the same at all the locations except one. The location that changed by this contingency was on bus P. The reason this occurred was because now the generator connected to bus P did not have to supply as much power as it did before to the load located on bus T. As a result, two marginal units are present in the system. The names of the two marginal generators are Garfield and Jefferson. The generator known as Garfield, which sells energy at 10 $/MWh, is the one that changed the price at bus P. This generator supplied much of the power needed to meet the demand since it had the highest capacity when compared to the other generators and because it had the lowest price. The other generator sold energy at 30 $/MWh. These two marginal units or generators are the ones responsible for the price on the different locations. The reason for this is because when a system is subject to congestion or contingencies, more generating capacity in the congested area is dispatched in order to meet the load requirements making the LMP higher as a result. Another change that occurred in this case was that generator Liberty did not dispatch any energy into the system and now Jefferson dispatched 94 MW into the system where as before it did not supplied any power.

For this case, the system had four of six generators dispatching energy at the moment. Of those four generators, two of them are dispatching energy at the maximum and only one of them is not at the limit. In addition, most of the transmission lines in the system carried a higher number of energy through them to meet the demand, when compared to the previous case without contingency. As a result, most of them transmitted more than half of the power limit that they had and one reached the maximum limit that it can provide. The line that reached its limit is the one located through buses P and Q. This situation caused a binding constraint in the system. The losses in this case were also not showed because the bidding curves of the units were piece-wise instead of continuous and the output adjusting doesn't result in the start or stop of the units.

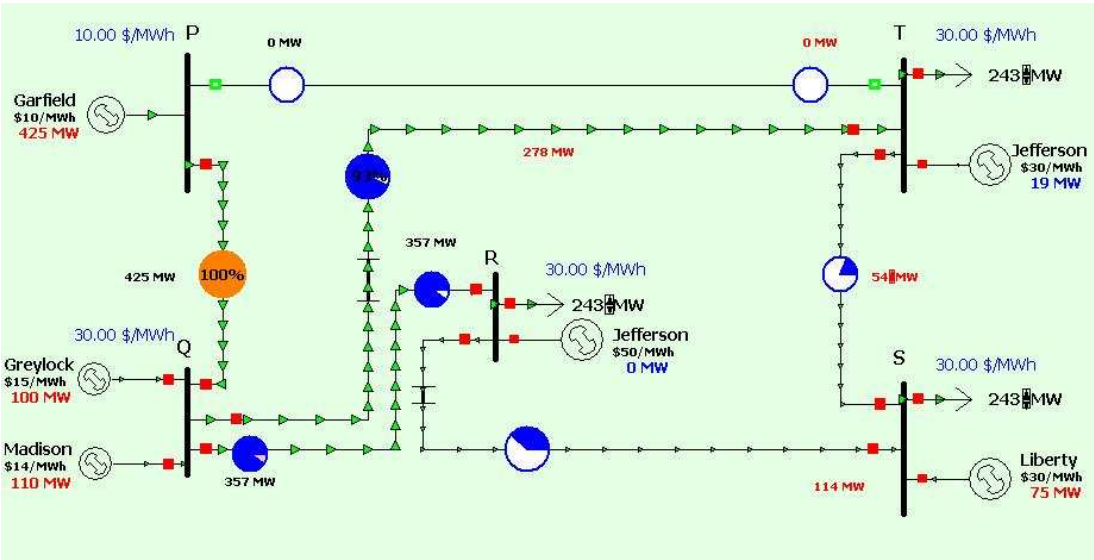


Figure 5.4: 5-bus system with line P-T removed

The next case analyzed with the transmission system model was the contingency of line P-Q being opened and removed from the system. As can be seen from figure 5.5 on the following page, the LMP's are equal in all the locations except one but they are equal or identical to the ones obtained in the previous case with line P-T being removed.

The results of the LMP's weren't affected when compared to the previous case studied. The reason for this situation was that the marginal units didn't changed. In other words, the same marginal generators Garfield and Jefferson that were identified for the previous case, stayed for this recent case. As a result, only two marginal units were present in the system, which are the ones responsible for the price on the different locations. The generators still sell energy at 10 $/MWh and 30 $/MWh respectively.

Another change that occurred was that generator Jefferson I was the only one not dispatching any active power into the system, where the other ones did supply power to the system. For the case discussed in this section, the system had five dispatching energy at the moment. Of those five generators, three of them are dispatching energy at the maximum and two of them were under the limits of power.

In addition, there are several transmission lines in the system carrying a high number of energy through them to meet the demand. However, when compared to the previous case without contingency there were not as many. Specifically, the line connected through buses Q and T were not transmitting much power to the system and the flow changed the direction it was taking on previous cases. This includes the case without congestion or contingencies. Also, there was another line in the model that reached its power limit. In this case, the line that reached its limit is the one located through buses P and T. These binding contingencies keep being located in places where a marginal unit or generator is located for the moment. For these first two cases they also keep happening on lines connected to bus P, which is where the lowest price generator is located and the most supply of power is happening. The losses in this case are also not showed because the bidding curves of the units are piece-wise instead of continuous and the output adjusting does not result in the start or stop of the units.

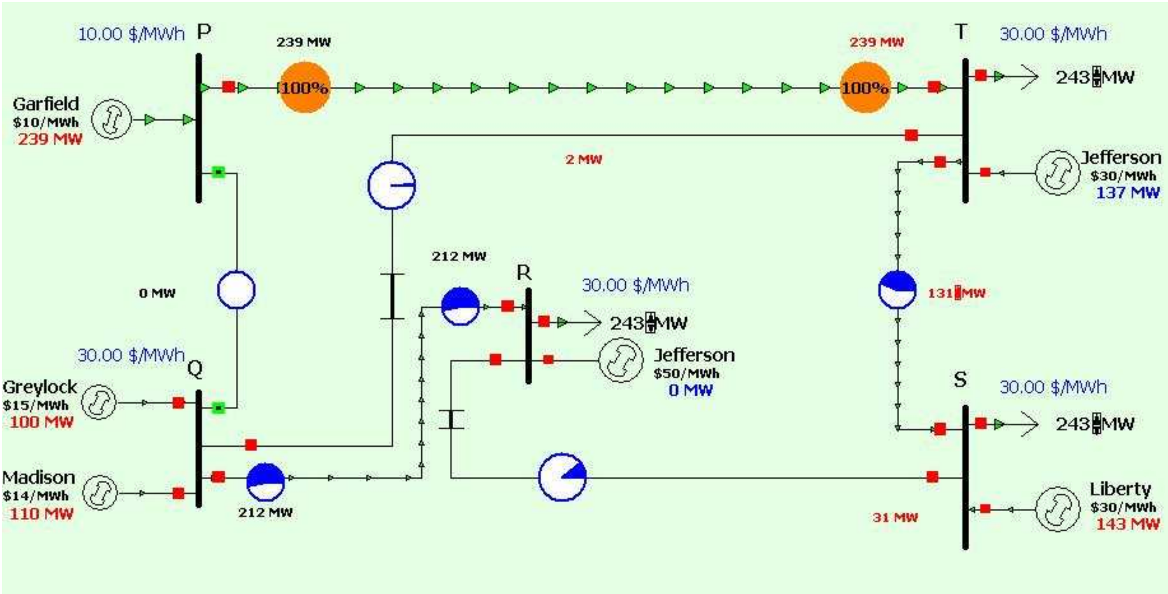


Figure 5.5: 5-bus system with line P-Q removed

Figure 5.6 analyzes the transmission system simulation with the contingency of line Q-T being removed from the system. From this figure you can see on the following page that the LMP's are not equal in some of the locations and some change has occurred when compared to the other cases studied so far.

The values of the LMP's have been affected considerably, when compared to the other cases studied for this project. The reason for this change in price was primarily because the marginal units have changed for the case studied now. In other words, the same marginal generator Jefferson that was identified for the previous case stayed for this recent case. However, the generators Greylock and Liberty are other marginal units that the system has. As a result, three marginal units are active in the system and are the ones responsible for the prices at the different locations or nodes of the model. Two of the generators are supplying power at 30 $/MWh while one is supplying power at 15 $/MWh respectively. Because of the increase in number of marginal units there are also more changes LMP in all of the buses available. Now the LMP on the buses that changed of price is being determined by the third lowest priced generator.

The generator Jefferson I is still not dispatching any active power into the system where as the other ones are supplying power to the system. Of the five generators supplying power to the system, two of them are dispatching energy at the maximum and three are between the limits of power. Also, each of the generators that are under the limits of power are supplying less than 100 MW at the moment which is below 35 percent of their maximum capacity.

In addition, a high capacity of power is flowing through the majority of the transmission lines in the model. Line S-T on the system model is the only one transmitting a low capacity of power at the moment. Also, there are two other lines in the model that have reached its power limit forming binding contingencies in the system. For example, one of the lines that reached its limit is the one located through buses P and T. The other line that reached its limit is the one connected through buses Q and R. There are still no losses being reflected in the simulation.

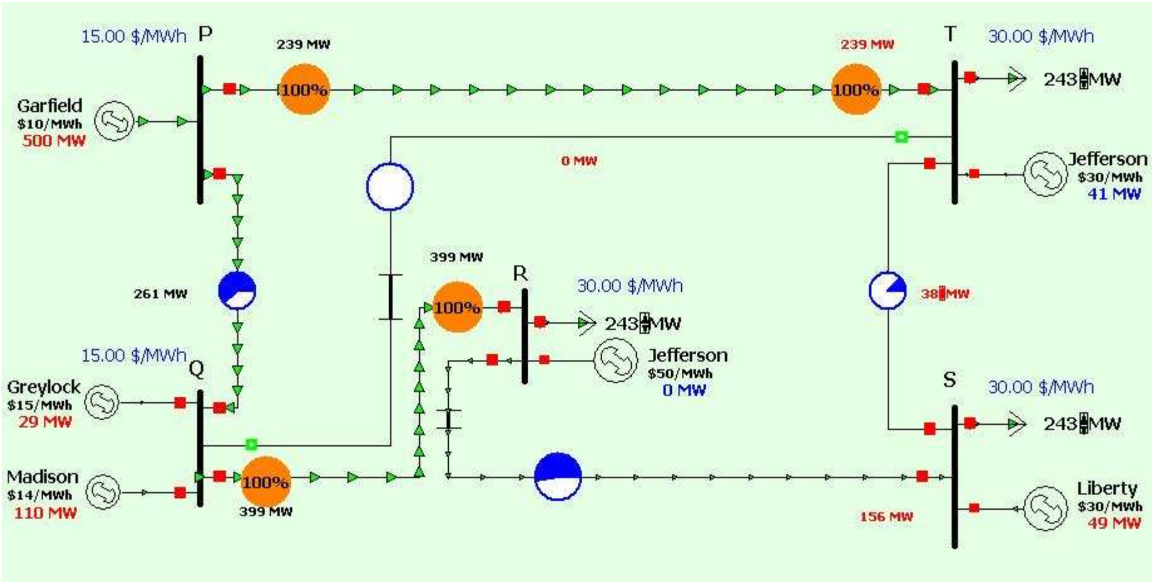


Figure 5.6: 5-bus system with line Q-T removed

The following case of the chapter analyzes the transmission system simulation with line Q-R being removed from the model. Figure 5.7 shows that the LMP's are not equal in most of the locations and has a significant change in comparison to the other cases studied in the previous pages of this section. The reason for this price change has been due to the fact that the marginal units have changed for this case. For example, the generator Jefferson is acting again as a marginal unit. But, the generators Madison and Jefferson I are other marginal units that the system has. As a result, three marginal units remain active in the system and are the ones that will help to set the prices at the different buses or nodes of the system model.

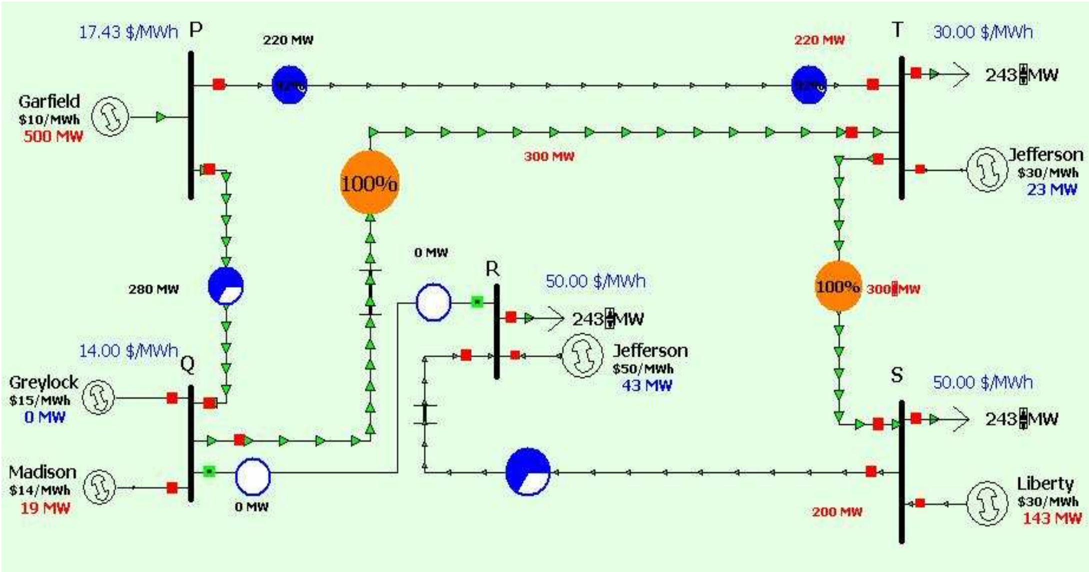


Figure 5.7: 5-bus system with line Q-R removed

Two of the generators are supplying power at 30 $/MWh while one is supplying power at 14 $/MWh respectively. Because of the increase in number of marginal units there are also more changes LMP in all of the buses available. You can see that the price on the reference bus has changed to 17.43 $/MWh and this is the energy component of the LMP's since there is no loss or congestion components in the reference bus. The reason for the price value is due to the fact that the generator connected to this bus has reached its limit. The rest of the prices in the system are affected by the congestion components in the system since there is no loss component.

The generator Jefferson I is still not dispatching any active power into the system where as the other ones are supplying power to the system. Of the five generators supplying power to the system, two of them are dispatching energy at the maximum and three are between the limits of power. Also, each of the generators that are under the limits of power, are supplying less than 100 MW at the moment which is below 35 percent of their maximum total capacity.

In addition, a high capacity of power is flowing through the majority of the transmission lines in the model as a result of removing this line. This is the worst case seen so far in this system simulation in terms of overall results obtained in the prices. It shows how important is this line to the system in general. Another thing that occurred in this case is that the power flow on line R-S changes the direction it took normally in most of the previous cases. Also, there are two other lines in the model that have reached its power limit forming binding contingencies in the system. For example, one of the lines that reached its limit is the one located through buses Q and T. The other line that reached its limit is the one connected through buses Q and S.

The next contingency case ran with the 5-bus system simulation was with the branch R-S being opened. Figure 5.8 shows the response of this power system to this contingency and the LMP’s on each node of the model. As can be seen form this figure, there is no congestion or constraint and there are no power losses because the values at the end of each transmission line remain equal. As result, the LMP’s are equal in all the buses or different trading points in the system and this contingency didn’t affect the overall response of the system it didn’t transmit too much energy to begin with. You can also see from the figure, that when there is an area in a system that is considered a congestion-free location the LMP’s are less than in other situations where congestions occur. In other words, the LMP’s are reduced to as much as they can. So when a system is subject to congestion or contingencies, more generating capacity in the congested area has to be dispatched in order to meet the load requirements making the LMP increase.

In addition, most of the transmission lines or branches in the model are carrying more than 200 MW of power through them. In terms of percentages each line is transmitting 60 percent or more of the power limit that they have. It can be said that the systems response is stable and its overall performance is acceptable.

For this case, the system has four of six generators dispatching energy at the moment. Of the four generators, three of them are dispatching energy at the maximum and one of them is not at either of its capacity limits. This generator is the one connected to bus T and is supplying energy into the system at 30 $/MWh. It can be said that this is the marginal unit of the system which sets the price for all of the areas in it. Another thing that can be seen or said is that most of the generation comes from the left side of the system which has the lower prices.

Figure 5.8 shows also how the system responds when there are no congestions present. It shows the Optimal Power Flow solution and the prices at each of the five buses. Finally, another thing that can be analyzes about this case is that the system reacted very similar to the original case without any contingency. The thing that changed besides the transmission output values through each line, which seems understandable was the marginal unit supplying 19MW at 30 $/MWh that came from generator Jefferson instead of Liberty which also sell power at the same price.

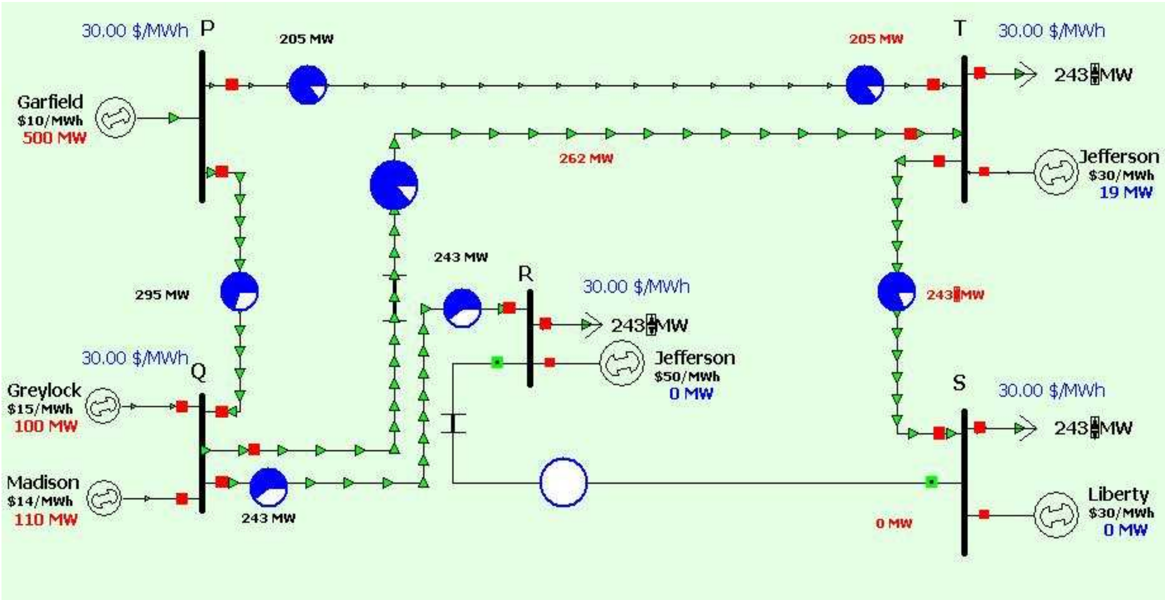


Figure 5.8: 5-bus system with line R-S removed

The last single contingency case analysis of the section studies the transmission system simulation with branch S-T being removed. Figure 5.9 demonstrates that the LMP's are not equal in some of the locations and have somewhat changed in comparison to the other cases studied in the previous pages of this section. In the majority of the locations the price has been reduced by half. The main reason for it is the changes in the OPF re-dispatch solution of generating power caused by removing this line. For example, the two marginal units for this new case are generators Greylock and Liberty. Also, the generators Garfield and Madison are the other generators dispatching at their capacity limit. These two generators are the ones providing the majority of the power because they are the ones that cost less for this system. The generator Liberty which sells energy at 30 $/MWh is supplying more power than the Greylock generator which sells energy at 15 $/MWh because that generator is the only one that can provide the difference in power needed by the load connected to that bus. You can see that the price on buses P, Q and T has changed to 15 $/MWh set by one of the marginal units while the price on the rest of the buses in the system are affected by the congestion components in the system or the loss component if it where present any losses in the system. The two Jefferson generators are not dispatching any active power into the system where as the other ones are supplying power to the system. Also, each of the generators that are under the limits of power, are supplying less than 100 MW at the moment which is below 35 percent of their maximum capacity combined.

Finally, less capacity of power is flowing through the majority of the transmission lines in the model when compare to the previous case as a result of removing this line. This is one of the worst cases seen so far in this simulation in terms of overall flow distribution through all of the lines. Figure 5.9 shows also how the majority of the power is being transmitted through branch Q-R. This caused for a binding constraint to be formed in this line. Another observation that can be said about this case is that line Q-T, which is an important line in the system connected to a series capacitor has reduced its percentage of power through it considerably. It would have been better for the overall performance of the system for this case to have obtained a higher value than the one obtained through this line.

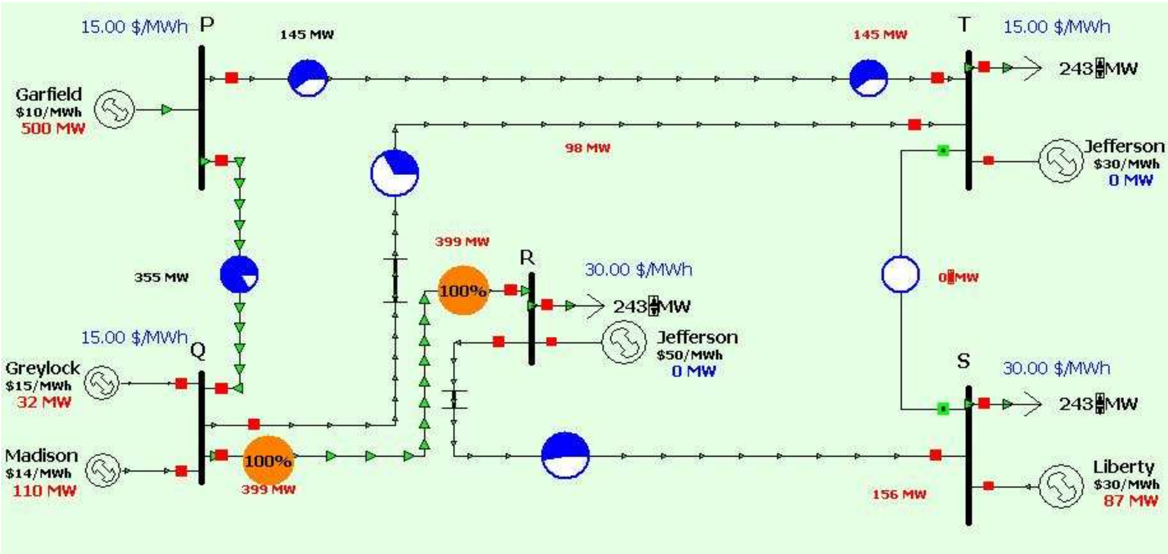


Figure 5.9: 5-bus system with line S-T removed

5.4 System Simulation with Controllable Lines

This section studies the impact that controllable lines have on LMP by making use of the 5-bus system model used throughout this project. The reason for pursuing this investigation is because the impact of transmission network congestion on locational marginal prices is an issue of importance to Electric Power Markets. The main objective is to reduce the price of energy being delivered to a specific location in the system when it is subject to congestions or to single contingency which is when it mainly increases the price in the system. Specifically this time, because this is when they are high-price generators actively selling energy during that time when congestions or contingencies occur. By being able to control a specific line in the system the flow of power in a location in the system can be controlled. It is important to understand that the only way that this concept proposed is going to be able to work is when the controllable line is neither subject to a single contingency nor a binding constraint. For our simulation case the controllable line is going to be the transmission line on branch R-S. A series capacitor is going to act as the element of control which is going to be used to vary its reactance. Initially, the interest is to set the value of negative reactance for the series capacitor to a low initial value to analyze how the system responds without the controllable element being activated. Later on, the parameters are adjusted to different values to see what effect it's having on the system. Hopefully, the responses will be close to the results expected.

Figure 5.10 demonstrates the effect of the controllable line on the LMP when the series capacitor negative reactance is in its initial value of 0.1. For this case it was decided to reduce the limit of power on line Q-R by half until it caused congestion in the systems simulation. The main reason for this is to cause a situation to study in which the generator Jefferson I will start to dispatch power into the system since it's the highest priced generator in our. As a result, this will cause an increase in the overall pricing in the system. Specifically, in the location or node in which this generator is connected that was increases to a price of 50 $/MWh. As can be seen from this case all of the locational marginal prices in each location changed drastically which was another reason for choosing this case. However all of them but one was reduced when being compared to the case without congestions. The exception was bus R which increased by 20 $/MWh. Another observation is that for example, the two marginal units for this new case are generators Greylock and Jefferson I. Also, the generators Garfield and Madison are the other two generators dispatching at their capacity limit. These two generators are the ones providing the majority of the power because they are the ones that cost less for this system. The two units Jefferson and Liberty are not dispatching any active power in the simulation. Also, each of the marginal that are under the limits of power, are supplying are not supplying significant amount of the demand needed. The flow through the majority of the transmission lines is considerable without causing any overcharge. At the moment of initial value the generator connected to bus R is supplying 110MW at 50 $/MWh. The power flowing through the controllable line is 67 MW. The hourly cost or total cost for these case model is of 12,434 $/hr. In the situation described, in which transfers into the control area at bus R are limited by the post-contingency flows over line Q-R, increased pre-contingency schedules over the line R-S would increase total transfers into the control area at bus R. The lower the reactance set on the controllable line, the higher would be the pre and post-contingency flows on line Q-R and thus the higher would be the total transfers into the control area at the bus. This can be illustrated by considering the impact of a reduction in the reactance of the line being controlled sufficient to increase pre-contingency flows over this line by 1MW. It can be further seen that it is still the case that it is a binding contingency, following the increase in flows scheduled on line R-S. It also portrays the flows following line Q-T, which is the binding contingency, and it is seen that the post-contingency limit on flows over line 6-5 is not violated. It is assumed that the flows on the controllable line are held fixed in the contingency. It can be seen that a 1MW increase in flows over the controllable line leads to a 1 MW reduction in the generator connected in the location and thus a $50 reduction in the as-bid production cost within the control area, without violating post-contingency limit on flows over line Q-R. The value of a MW of power delivered over the controllable line is therefore 50 $/MWh, the change in the cost of meeting load at R by increasing deliveries over this line. In particular, it is important to note that the scheduling of an additional MW over the controllable line does not reduce schedule transfers over the AC interconnects, but leads to an increase in the total transfers. Thus as long as the post-contingency flows on the line R-S were at least as large as the pre-contingency flows, an increase in pre-contingency schedules on the controllable line would increase total deliveries at bus R by 1 MW and thus the appropriate proxy bus price for deliveries over the controllable line would be this bus price.

The schedules over the controllable line appear to be a disequilibrium at the prices at bus S and R as incremental schedules on the controllable line would be profitable. The schedules shown would, however, be equilibrium if there were a pre-contingency limit on flows over the controllable line of 67 MW, either to avoid overloading the line R-S or to avoid overloading the lines close to this one. In this case, prices and schedules would be as shown, but no entity would be able to increase schedules over the controllable line. Alternatively, the line R-S could be a DC line with operating costs. The schedules shown would also be an equilibrium if the charge for scheduling power over the controllable line were 35 $/MWh. If the controllable line were scheduled by the ISO of the control are used in this case simulation, it would increase the schedules on the controllable line until either the price difference between bus S and R disappeared or one of the constraints became binding. Abstracting from imperfect information, the pricing system would provide market participants with the same incentive, as it would be profitable to increase schedules on the controllable line until one of this constraints became binding. It is assumed in this discussion that the line Q-R is an external tie line. Imports flowing over the rest of the lines close to the area of interest would all be priced as part of the reference bus price, while the schedules flowing over the controllable line would be paid at a price equal to the LMP price on location R. The figure below shows all the data described.

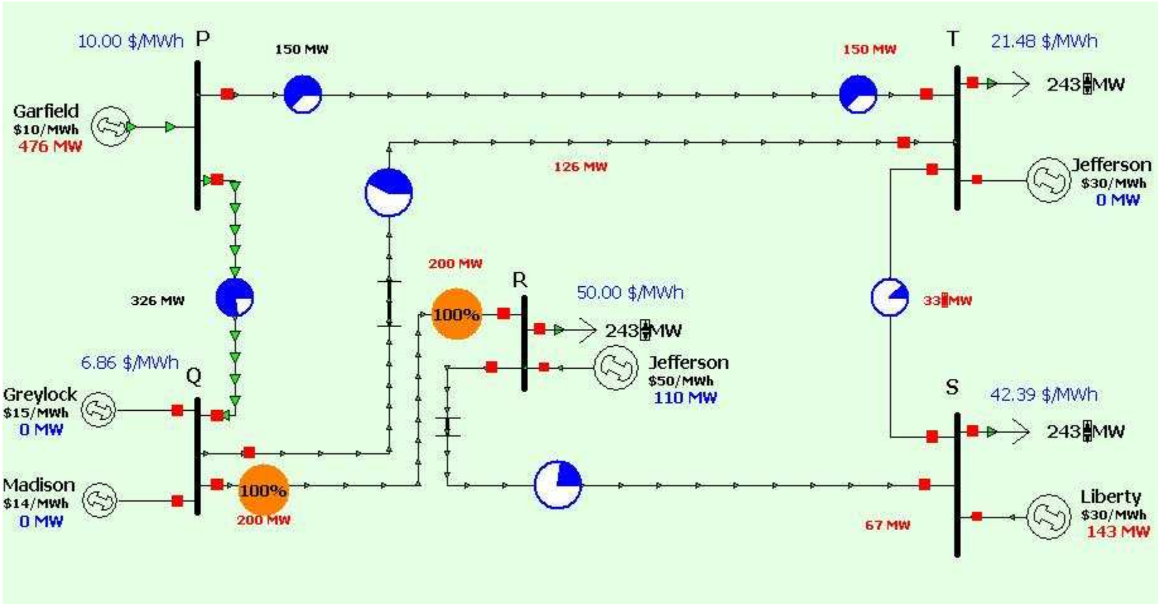


Figure 5.10: 5-bus system with controllable line in its initial value

After seeing the results for its initial value decided the reactance of the series capacitor continued to increase by 50 percent. The reason for increasing the value and not decreasing was that the amount of generation by the marginal unit connected at this bus was increasing instead of reducing which is what was desired. In some cases the LMP's in the buses changed as a result of this variation of reactance on the element of control. The value on the element of control continued to increase by this ratio until the results were stable or a pattern was seen. Since it continued to go down the same pattern it was stopped after four tries. With this method the pricing improved considerably and it helped the overall response of the system.

Figure 5.11 shows the results obtained with the controllable fixed at a reactance of 0.2. As can be seen from the figure the values were improved when being compared to the previous situation. Generator Liberty is not is dispatching energy this time and it is being dispatched instead by a combination of generators Greylock and Madison which sell energy for less pricing. This case portrays a slightly different set of pre-contingency flows over the same transmission grid and it is again the case that there are binding pre-contingency transmission constraints. You can see that the total injections at bus Q are higher in this scenario than in the previous one, although the flows over the line R-S are unchanged. The reason for this is that in this case the flows over the controllable line are not fixed, and thus a higher level of injections can be accepted at bus 3 without overloading line Q-R. It can be seen from the figure that the power flow over the line connected through bus Q and R have reached its limit. However, the reactance of the controllable line is fixed in the contingency and so the post-contingency flows over this line exceed the pre-contingency schedules. Because the post-contingency flows over Q-R are a binding constraint, no additional imports could be scheduled from bus Q, given the settings on the controllable line, and the price of power at this bus would be set by a bid of the marginal generator at that location, which would be 15 $/MWh in this situation, contrary to the previous case. Also, the flows on this controllable line are well below the limit of 200MW and so the controllable line is not a binding contingency and would not limit the level of imports from generation at bus Q. In the situation described by this case, increased schedules over the line R-S increase total transfers into the control area at bus R. The lower the reactance set on this line, the higher would be the post-contingency flows and thus the higher would be the total transfers into the control area. This can be illustrated by considering the impact of a reduction in the reactance on the controllable line sufficient enough to increase contingency flows over this line by 1 MW. This situation was portrayed on the study and you could see that a 1 MW increase in pre-contingency flows over the line R-S allows total injections at Q to be increased by 141 MW, thus reducing generation in the control are by more than the change in pre-contingency flows over this line. Thus, the change in total production costs on the control area resulting from a 1 MW increase in schedules over the controllable line is $28.

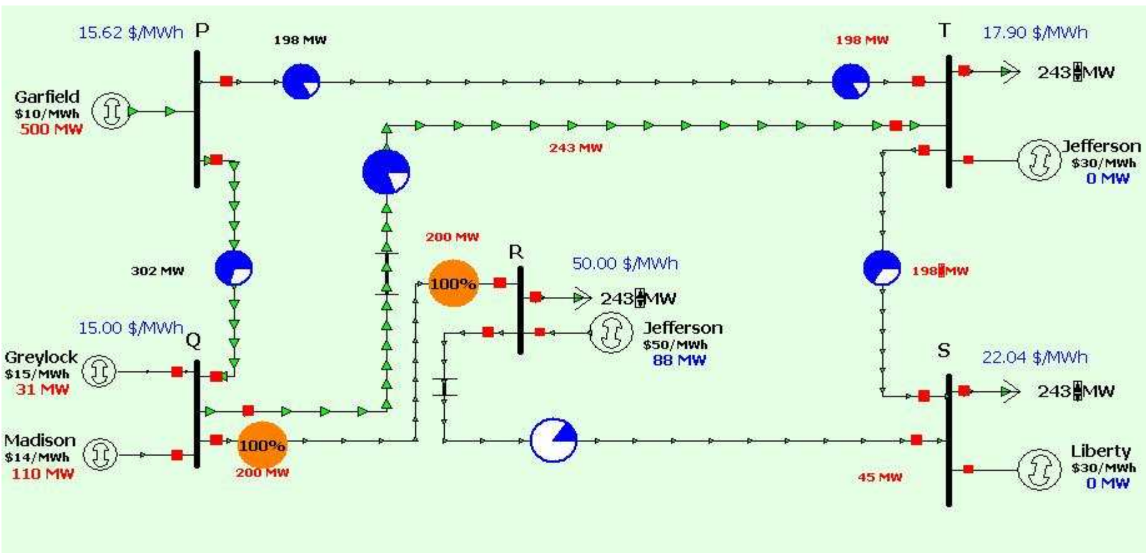


Figure 5.11: 5-bus system with controllable line increased twice its initial value

This change in production costs results from a reduction of 12 MW in the amount of energy injected at bus R at a price of 50 $/MWh and an increase in the flows into the control area on the open ties at a price of 15 $/MWh. The 1 MW required to balance load is delivered over the controllable line. It can be further seen that it is still the case there is not a binding contingency in most of the lines in the system, including the controllable line. In order for the dispatch and pricing system to take account of the full benefits of changes in scheduled flows over the controllable line, it is necessary in this circumstances for the ISO to not only receive information regarding schedules on the controllable line. As observed, the price of power delivered at bus R over the controllable line can be determined by the basic LMP pricing equation. In this equation, the price of power delivered to the bus over the controllable line would be determined by the sum of the reference bus price, losses at bus R relative to the reference bus and the sum of the shadow price of the binding constraint times the shift factor on the binding constraint of deliveries at R over the controllable line. If this bus were the reference bus and pre- and post-contingency deliveries over the line R-S were fixed at the pre-contingency level as in the first case, then the shift factor in the binding contingency would be zero, and the bus price of power delivered the line would be equal to the price at the reference bus. If deliveries over the controllable line rose in the contingency, then the shift factor of increased deliveries over R-S would have a negative post contingency shift factor over the line Q-R and the LMP of power delivered over the controllable line would exceed the bus price. Increased deliveries over the line R-S have a negative shift factor of 0.023 over the controllable line is the price at the reference bus plus 0.96 times the shadow price on the constraint line of 35 $/MWh.

The other class of pricing outcome is that in which the outage of the controllable line is one of the binding contingencies. In theses cases, the reference bus price of power delivered over the controllable line could be lower than the price at the delivery point of the controllable line. The pricing in these situations would also be governed by the generalized formulation equation shown in the previous chapter.

Finally, the last simulation was taken with a reactance value of 0.25. It can be seen that the characteristic of the lines connected to bus Q and R have changed for this case. It shows post-contingency flows of the outage and it is seen that the limit on flows over the line Q-R is binding in this contingency like the rest of the cases. It also portrays the post-contingency flows following the variance of the controllable line, and it can be seen that flows on the line with binding contingency is at their emergency limit. Thus, no additional flows could be scheduled on the controllable line without overloading this line in the contingency in which line R-S is out and no additional flows can be scheduled over the ties without overloading it. Although there are two other lines that can become binding constraints, they are redundant and only two marginal generators are present. The flows over the controllable line are not marginal, since it does not matter whether energy is scheduled to flow over the controllable or non controllable line. The values of energy scheduled to flow over the controllable line can again be showed by considering the impact of a 1MW increase over the controllable line. The pre-contingency flows over this transmission system increased to 38MW. It is important to note however that the injections at bus Q and R are unchanged. The reason that the total injections at these buses are unchanged is that this line is a binding contingency and the pre-contingencies schedules over this line connecting the two buses are irrelevant during the course of this case. The impact on the cost of meeting load at bus R of scheduling another MW to be delivered over the controllable line would be exactly the same as the impact of another MW scheduled to flow over the open ties. The reference bus price for deliveries scheduled over line R-S would therefore be the bus S price, as increased deliveries over the controllable line would displace 22 $/MWh delivered on the open ties. Thus, the shadow price on the line Q-R constraint would be 7 $/MWh, and generation at the reference bus would have a 0.7830 shift factor on that line in that contingency. After running all simulation cases an accumulation of all the results obtained from the different variations were made to the controllable line and its element of control, with the parameters that we were monitoring that were of interest for our analysis. There was a steady decline in all of the results proving our point of the importance of this method to help compensate when congestions occur and prices increase.

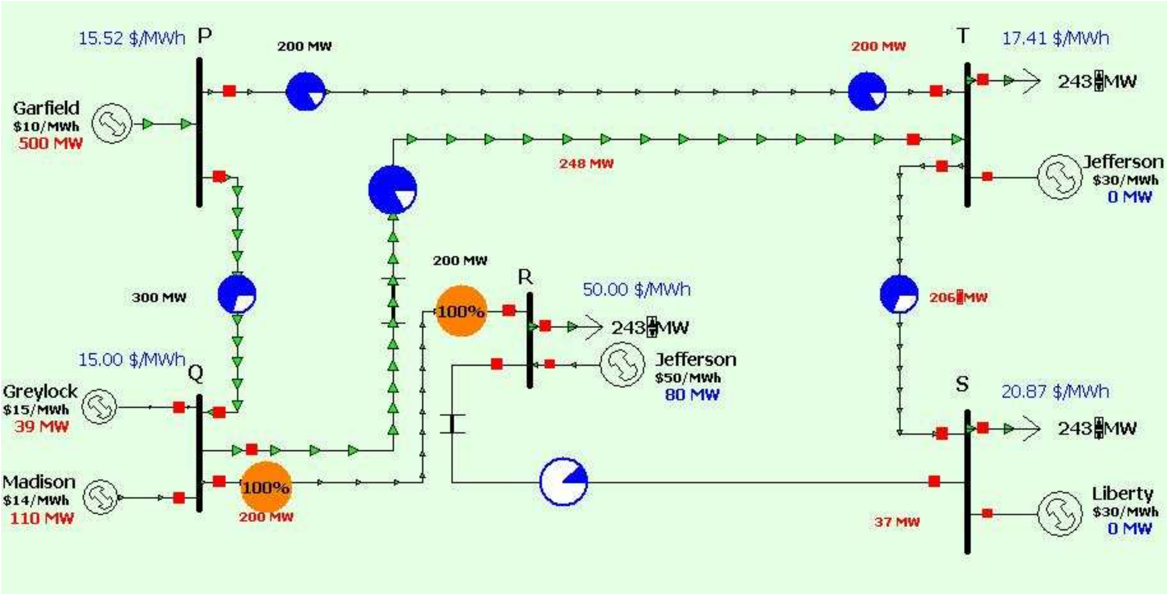


Figure 5.12: 5-bus system with controllable line increased to 0.25 its reactance

5.5 LMP Calculation

This section explains the methods used to calculate the LMP as well as the total hourly cost for the system simulation used for this project. It is important to make sure that these parameters are well calculated and that they make sense. Also, it is important to know where these values come from. The reason for this is because these are basically the results that are going to help us analyze our situation better and say if the method of controllable lines is successful or not. The purpose of this chapter is to understand where these values come from and show an example for each case. The purpose is to also compare the results that the software gave us with the results obtained from the different calculations, to see if they provide similar results.

Again, LMP is a cost of optimally supplying an increment of load at a particular location while satisfying all operational constraints. One can think of the LMP as a change of the total production cost to deliver additional increment of load to the location. LMP's are usually produced as a result of economic dispatch. LMP's can be calculated looking ahead. The equation below shows the LMP equation with each of the three components. This equation is used to calculate the LMP value at one location for one of the cases implemented in this study. The case used is the 5-bus system with controllable line set to twice its initial value.

$$\lambda_i = \lambda - LF_i \cdot \lambda + \sum_{k=1}^{K} S_{ik} \cdot \mu_k$$

Where:

λ_i= Locational price at bus i

LF_i=Marginal loss factor at bus i

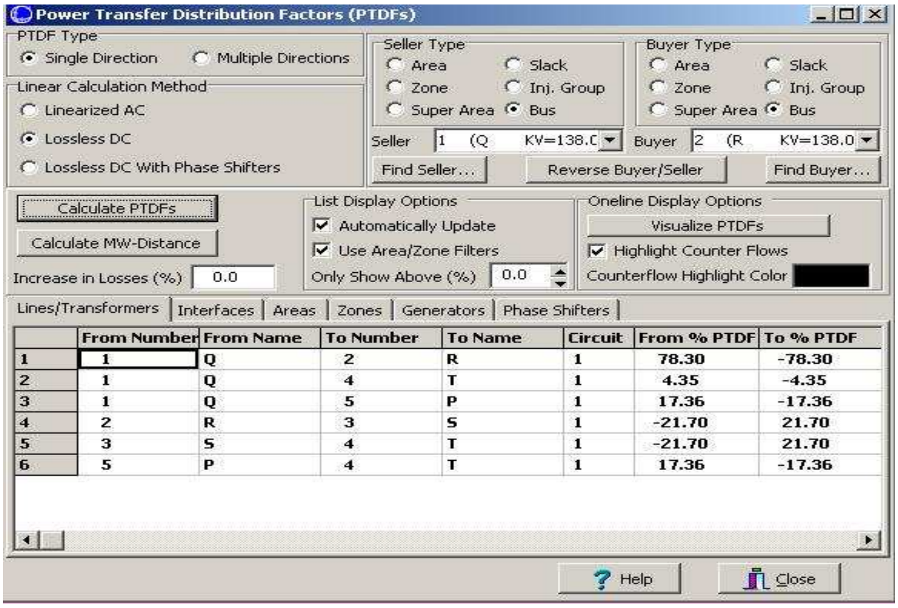
λ=Locational price at reference bus

S_{ik}= Shift factor of branch k to the generator i,

μ_k= Shadow price of constraint j in contingency k

There are several things to know and consider about the variables in this equation before making use of it in our example. The energy component is the same for all locations and equals to the system balance shadow price. Congestion components equal zero for all locations if there are no binding constraints. The loss component has been zero during the course of this project. Shift Factors are the PTDFs when one of the points is always a reference bus. In other words, shift factor is the sensitivity of the line flows to the change in injections at the buses. SF shows how the flow in the branch will change if the injection at the bus changes by one MW. Because the reference bus always makes up for the change in the injection, shift factor values are dependent on the location of the reference bus. This is true even for the DC model. By definition, the shift factor at the reference bus equals to zero. The shift factor will reflect the change of the line flow due to change in the injection. Each shadow price reflects the effect of relaxing corresponding constraint by one unit on the value of the objective function, which means the change of total cost. The shadow price λ of the system balance constraint is one for the whole system only one system balance equation. Each transmission constraint k has its own shadow price μk. Some constraints may be binding. Binding constraint is the constraint that turns into equality for the optimal solution. For example, a particular branch has to be operated at its limit. The shadow price of the binding constraint is non-zero; while the shadow price of the constraint that does not bind is zero. The system balance constraint always binds, so its shadow price is never zero. This means that there is always a price to support system balance. If there are no binding transmission constraints, there is no congestion in the system.

Table 5.3 shows the shift factors for all of the branches in the system. The branch of interest is the one connected through bus Q and R. The calculation method used is the linear lossless DC method or model.



	From Number	From Name	To Number	To Name	Circuit	From % PTDF	To % PTDF
1	1	Q	2	R	1	78.30	-78.30
2	1	Q	4	T	1	4.35	-4.35
3	1	Q	5	P	1	17.36	-17.36
4	2	R	3	S	1	-21.70	21.70
5	3	S	4	T	1	-21.70	21.70
6	5	P	4	T	1	17.36	-17.36

Table 5.3: Shift factors for controllable line case

The DC model is based on the linearization of the power flow equations around certain base point to avoid iterations. This allows solving large series of power flows within reasonable time frame. This model is also being used in the economic dispatch to make it possible to use linear programming technique. Sinusoidal function of the flow is replaced with the linear function. In the quite wide range of normal conditions, the error of linearization is reasonably small. When the loading grows close to the limit, the errors are getting high. This is usually far above the thermal limit of the line. The following assumptions are made for DC idealization: all branch resistances are equal to zero, all voltage magnitudes are constant, and the differences of phase angles between voltages at the ends of any branch are within normal loading range where the errors are not very high. Under these assumptions, there are no losses in the system because of no resistance in the system; active power solution can be obtained without solving simultaneously for reactive power. For DC model, only active power injections and withdrawals are given. The result of calculation is just voltage phase angles. This is a system of linear equations and can be solved very quickly without iterations. Very often this model is used for rough estimates of the system conditions and calculating multitude of different cases in a very short period of time. LP methodology uses DC network model to calculate LMP's. In the DC model, there are no losses in the transmission lines, but sum of all generation is greater than sum of all loads by the amount of losses. This brings up an issue of where to put losses to keep the balance if there are no losses in the network. In a traditional approach, slack bus always makes up for losses, which means that all system losses are withdrawn at one bus. This may significantly distort the power flow in the network and, as a result, change LMP's. The slack bus that has been selected as a reference for shift factors determines the location of the losses in the network.

The source bus is the Q bus and the sink bus is the R bus. Both of them are connected to the binding constraint line. The energy component is determined by the reference or slack bus and has a value of 15.62 $/MWh in this case. The shadow price is determined by the difference in price obtained when comparing the original case and the case with relaxing the constraint by 1MW. To accomplish this task sensitivity analysis has to be implemented. The reason for this is because sensitivity is another way of linearization. It shows how a power flow variable changes with the change of another value. Sensitivities are very widely being used in different industries for real-time control. PTDF determines a change in the power flow at each line when one MW is transferred from one bus of the network to another. When one MW is transferred from one bus to another, it affects every single flow in the network. In addition, depending on location of the two buses, the transfer causes different losses which are impossible to predict, so reference bus makes up for losses injecting additional MWs.

Table 5.4 shows the values obtained for each of the variables in the equation and percentage of error obtained when comparing this calculation value with the value obtained in the simulation. The percentage of error is considered reasonable and acceptable since it is only around two percent.

Energy component λ($/MWH)	Congestion component		Calculation Value ($/MWh)	Simulation Value ($/MWh)	Error (%)
	S_{ik}(%)	μ_k($/MWh)			
15.62	78.30	2.40	17.50	17.90	2.23

Table 5.4: LMP calculation

Figure 5.12 shows a simulation summary for the case discussed and in that summary shows the value of the hourly cost just mentioned. Table 5.5 shows the procedure used to calculate the hourly cost ($/hr) of the system. The simulation value is of 12,436 $/hr for the controllable line case in its initial value and the calculated value is of 12,420 $/hr. The error is of 0.1286 percent which is almost zero proving the reliability of the calculation of both parameters. The errors come from the linear programming (LP) calculation method used by the software which always provides some type of errors in the results since they work with linear equation approximations.

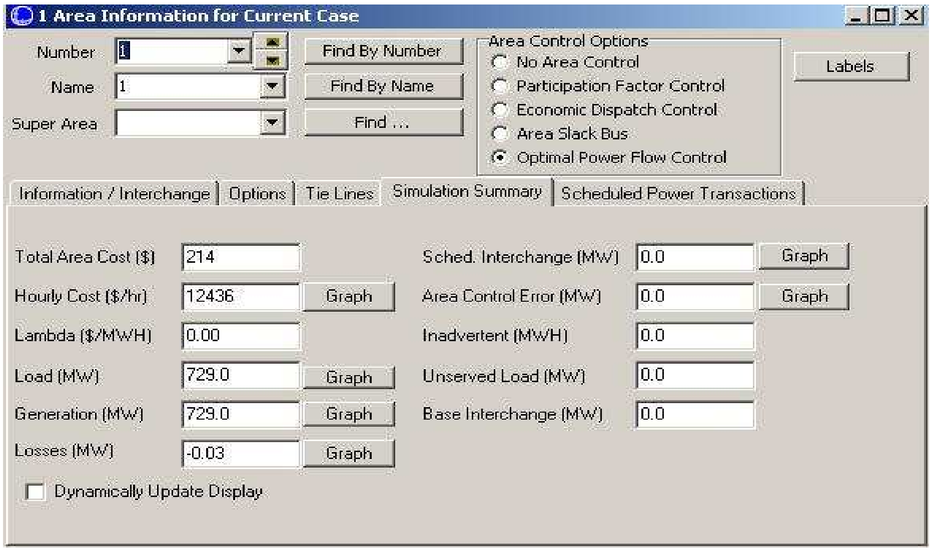


Figure 5.12: Simulation summary

Calculated Value ($/hr)	Simulation Value ($/hr)	Error (%)
12,420	12,436	0.1286

Table 5.5: Hourly cost calculation

Finally each LMP can be split into three components. The energy component is the same for all locations and equals to the system balance shadow price. Congestion components equal zero for all locations if there are no binding constraints. The loss component is the marginal cost of additional losses caused by supplying an increment of load at the location. At the reference bus, loss factor and all shift factors equal to zero. This means that both loss and congestion components are always zero at the reference bus. As the result, the price at the reference bus always equals to the energy component. Table 5.6 demonstrates the LMP components for each of the five buses in the system when it is subject to a controllable being activated in the system.

Location	Energy Component($/MWh)	Congestion Component($/MWh)	LMP($/MWh)
P	10.00	0.00	10.00
Q	10.00	-3.14	6.86
R	10.00	40.00	50.00
S	10.00	32.39	42.39
T	10.00	11.48	21.48

Table 5.6: LMP Components

6 ANALYSIS

6.1 Analysis of Results

This section of the chapter analyzes the impact that controllable lines have on locational marginal price. Congestion occurs when the transmission network is not sufficient to transfer electric power according to the market desire. When there is no congestion and there are no power losses or they are ignored because they aren't of too much impact into the system, the LMP's are equal in all the buses. You can also see that in an area in a system that is considered a congestion-free location the LMP's are less. The reason for this is because when a system is subject to congestion or contingencies, more generating capacity in the congested area is dispatched in order to meet the load requirements making the LMP higher as a result. With controllable lines it is possible to reduce the price of energy in a specific location in the system when it is subject to congestions or to single contingency which is when it mainly increases the price on the system. Also, by being able to control a specific line in the system it is possible to control the flow in a location in the system during this time and be able to reduce the amount of energy needed from a high-price generator. It is very important to understand that the only way that this concept proposed is going to be able to work is when the controllable line is neither subject to a single contingency. For our simulation the controllable line was the transmission line on branch R-S. A series capacitor is going to act as our element of control which is going to be able to vary the lines reactance. Initially, the value is set to an initial value because to see how the system responds without the controllable element being activated. Later on, the parameter is adjusted to different values to see what effect it's having on the system. For this case the limit of power over line Q-R was reduce by half until it caused congestion in the systems simulation. The main reason for this was to cause a situation where the generator Jefferson I will start dispatching power into the system since it's the highest priced generator in our. As a result, this will cause an increase in the overall pricing in the system. As can be seen from this case all of the locational marginal prices in each location changed drastically which was another reason for choosing this case. However all of them but one was reduced when being compared to the case without congestions. Another observation is that for example, there are two marginal units for this case. Also, there are some generators dispatching at their capacity limit. These generators are the ones providing the majority of the power because they are the ones that cost less for this system. The rest are not dispatching any active power in the simulation. Also, each of the marginal units that are under the limits of power, are supplying are not supplying significant amount of the demand needed. The flow through the majority of the transmission lines is considerable without causing any overcharge. After seeing the results for its initial value the reactance of the series capacitor continued to vary by a 50 percent increase. The reason for increasing the value and not decreasing was that the amount of generation by the marginal unit connected at this bus was increasing instead of reducing which was the purpose all along. After increasing the values the results began to be favorable because of the increased efficiency. The values on the element of control continue to increase by this ratio until the results stabilized. Since it continued to go down the same pattern it was stopped after four tries. With this method the pricing improved considerably and it helped the overall response of the system. An accumulation of all the results obtained from the different variations were made to the controllable line and its element of control, with the parameters that were of interest for our analysis. There was a steady decline in all of the results proving our point of the importance of this method to help compensate when congestions occur and prices increase. Table 6.1 shows a summary of the results obtained from the controllable line case.

Controllable Line Reactance (pu)	Jefferson I @50 $/MWh Power (MW)	Line R-S Power (MW)	Hourly Cost ($/hr)
0.0000	117	74	14,539
0.0500	113	70	13,470
0.1000	110	67	12,434
0.1500	99	56	11,784
0.2000	88	45	11,396
0.2500	80	37	11,136

Table 6.1: Controllable Line Case Summary

Choosing slack bus is important in every power system model because it is the one responsible for balancing powers in the system and also absorbing all the uncertainties or loses in the system. From analyzing the results, it is also the one that determines the value for the energy component in the LMP calculation. When slack bus location changes, all the flows change too. Losses also change with the change of the location of the slack bus. Therefore: AC Power Flow is dependent on the location of the slack bus. The higher the imbalance between calculated and “guessed” losses is, the higher the difference. Series Capacitors are a good choice over phase shifter because its model can affect more directly the reactance of the system which is something that could be done with phase shifters. In other words, its internal reactance wasn't present in the model and wasn't varying as the other parameters were modified, like for example the angle. The marginal units or generators are known by the n+1 rule that states that for n binding constraints, there is at least n+1 marginal unit`s. The losses in this case are also not showed because the bidding curves of the units are piece-wise instead of continuous and the output adjusting doesn't result in the start or stop of the units. The most marginal units that were present in a case were three because two binding constraints were formed. Because the reference bus always makes up for the change in the injection, shift factor values are dependent on the location of the reference bus. By definition, the shift factor at the reference bus equals to zero. The shadow price of the binding constraint is non-zero; while the shadow price of the constraint that does not bind is zero. The system balance constraint always binds, so its shadow price is never zero.

In the circumstance in which a controllable line connects two control areas, each ISO could operationally model all generation in the other control area as if it were at a single location, if this provided the best operational model. It is possible, however, that the ISO could find that the dispatch required for the other control area to maintain schedules on the controllable line differs from that required to sustain imports over the AC interconnect and thus that the operational model would be improved by modeling the imports over the controllable line having a different generation source than the imports over the AC interconnects. In this case, the ISO could adopt a multiple reference bus operational model, with one reference bus for flows over the controllable line and another reference bus for flows over the AC interconnection. This second reference bus need not, be located at the end of the controllable line. Nor would the location of this second reference bus be the same as the pricing point for the controllable line would almost certainly be different. The cases on the chapter above have considered cases in which schedules over the controllable line were determined by the operator of the controllable line or its customers. In this situation, it is desirable for the pricing system to provide incentives for the line operator or market participants to schedule the efficient level of transactions on the controllable line. An alternative circumstance would be that in which the schedules on the controllable line were determined by the ISO in the course of its overall least cost dispatch. In this circumstance, there would be no differential pricing of power scheduled over the controllable line, as the schedules would be determined by the ISO not by the market participants.

In general, the scheduling of the controllable line by the ISO would, absent market power, maximize the revenues generated by the controllable line. This generalization might not be valid, however, if the operation of the controllable line needed to be coordinated with the operation of other facilities not under ISO control. This would include particular generators capable of delivering power to the facility. The transmission pricing system for controllable lines between the same two control areas. It could also be applied to operator controlled controllable lines on an interface on which some controllable lines were scheduled by the ISO.

Table 6.2 shows a summary of the results obtained for the different case of single contingency analysis performed. Contingency Analysis is a process of identifying the consequences of potential component outages in the system. Contingency could be a line, transformer, breaker or generator outage or their combination. Each contingency is described by the set of outaged components. The main goal of contingency analysis is to determine conditions violating operating limits. These limits include: branch overloads, abnormal voltages, interfaces, and voltage angle differences. Contingency analysis is done both in real time and in a study mode. The components that could be violated are called limiting or monitored elements. They determine the constraints on system operating conditions. Transfer limits could be thermal and stability. A thermal limit is determined by the thermal rating of the limiting element. The reason for it is that you want the maximum amount of power that can flow through the element without burning it. A stability limit is determined by the consequences of dynamic or transient processes in the system. Example is the stability of the synchronous generators that forces certain limitations on the power transfer due to the overload happening as a result of the short circuit at a substation. Stability limits are usually calculated in off-line studies that requires significant amount of time. There are new tools that may be used in the near future to calculate stability limits in real time. The following steps are performed by most of the contingency analysis tools: calculate base power flow (state estimator in real time), check all limiting elements for violations, and screen all the contingencies. This is a process of simulating each contingency from the given set one by one by a DC model-based quick power flow analysis, check each for potential violations, run all suspicious contingencies through the full AC power flow analysis, report violations in base case and under contingencies.

From the first column in the table below you can see that most of the LMP prices stayed the same at all the locations except one. This occurs because now the generator connected to bus P doesn’t have to supply as much power as it did before to the load located on bus T. As a result, two marginal units are present in the system. Also, most of branches are transmitting more than half of the power limit that they have and one reached the maximum limit that it can provide. In the next column the LMP’s are equal or identical to the ones obtained in the previous case with line P-T being removed. The reason for this situation was mainly due to the fact that the marginal units didn’t changed. In addition, there are several transmission lines in the system carrying a high number of energy through them to meet the demand. However, when compared to the previous case without contingency there aren’t as many. From the following column you can see that the values of the LMP’s have been affected considerably when compared to the other cases. The reason for this change in price was primarily because the marginal units have changed for the case studied now. Because of the increase in number of marginal units there are also more changes LMP in all of the buses available. Also, each of the generators that are under the limits of power is supplying less than 100 MW at the moment which is below 35 percent of their maximum capacity and two binding constraints were formed. It can be seen from the fourth column that the LMP’s are not equal in most of the locations and has a significant change in comparison to the other cases studied in the previous pages of this section. The reason for this price change has been due to the fact that the marginal units have changed for this case. This is the worst case seen so far in this system simulation in terms of overall results obtained in the prices. It shows how important is this line to the system in general. Another thing that occurred in this case is that the power flow on line R-S changes the direction it took normally in most of the previous cases. As can be seen form this figure, there is also no congestion or constraint and there are no power losses because the values at the end of each transmission line remain equal. As result, the LMP's are equal in all the buses or different trading points in the system. It didn't affect the overall response of the system it didn't transmit too much energy to begin with. Another thing that can be seen or said is that most of the generation comes from the left side of the system which has the lower prices and the marginal unit changed in comparison to the simulation without congestion but the prices stayed the same since both generators sell power at the same price. Finally, the last column shows that in the majority of the locations the price has been reduced by half. The main reason for it is the changes in the OPF re-dispatch solution of generating power caused by removing this line.

Location	P-T	P-Q	Q-T	Q-R	R-S	T-S
P	10 $/MWh	10 $/MWh	15$/MWh	17.4 $/MWh	30$/MWh	15$/MWh
Q	30 $/MWh	30 $/MWh	15$/MWh	14 $/MWh	30$/MWh	15$/MWh
R	30 $/MWh	30 $/MWh	30$/MWh	50 $/MWh	30$/MWh	30$/MWh
S	30 $/MWh	30 $/MWh	30$/MWh	50 $/MWh	30$/MWh	30$/MWh
T	30 $/MWh	30 $/MWh	30$/MWh	30$/MWh	30$/MWh	15$/MWh

Table 6.2: Single Contingency Case Summary

7 CONCLUSION AND FUTURE WORK

7.1 Conclusion

Throughout this dissertation the impact that controllable line pricing has on power system network model markets has been presented. Specifically, on locational marginal price which is a cost of optimally supplying an increment of load at a particular location while satisfying all operational constraints. Moreover its importance resides on its extension to the power system in general. For example, a transmission line can be controlled by varying the impedance of a line or the phase angle at a certain location. It was described the motivations behind studying this new concept, its numerous applications as well as its potential on future electricity energy markets. The system modeling and mathematical procedures were described in some detail also. A small working system model was simulated by making use of the Power World program, a case study situation was conducted on worst-case scenario basis that demonstrated its functionality and performance.

The work presented describes and demonstrates a plausible solution to reducing energy cost on electrical power systems. The method proposed could be applied and implemented to numerous kinds of power system reducing cost while maintaining security levels. In Chapter 5, the model of the 5-bus base case simulation was implemented for purposes of proving the method used in this project. There was an opportunity from this project to learn of concepts from power system economic like LMP calculation, OPF and Market models.

Furthermore the concept of the angle reference bus as the reference for voltage vectors was discussed; in power flow calculations a reference, slack or swing bus is always selected. It is recalled that when calculating power flow, one has to specify all nodal loads and generation. It is impossible to guess the total value of losses in the system before the power flows are calculated. Power system engineers resolve this problem by selecting a location in the network that would balance any difference between generation and load (generators have to supply losses in addition to the load). This concept is very important in understanding sensitivities and LMP components later. The reference bus and the slack bus do not have to be located at the same point of the network, however, in most cases, they are at the same location. That is why these names are being used interchangeably.

When there is congestion, it affects electricity market, and the generating capacities in the congested area will be in relative scarcity. Networks of energy have some particular characteristics, in the congested area; all LMP's are higher than those without congestion. If generators bid in strategies to exercise the market power, they can gain high additional profits. Congestion will cause relative scarcity of generating capacities in the congested areas, so the generation companies in these areas have locational market power. If there is congestion, the preferred pre-dispatch plan of the generating units has to be changed .The more expensive units in the congested areas are dispatched to supply energy in order to meet the requirement of the customers. So the profits of the generation companies in the congested area increase while the ones for generation companies in the congestion free area decrease. The consumers in the congested area have to pay more to purchase their electricity energy, while the consumers in the congestion free area pay less for the energy. More expensive units provide some electricity energy originally offered by cheap units. So the transmission congestion invalidates the optimization of generating resources in the whole network. And it causes deadweight welfare loss and hinders the market efficiency in power systems. So the market operation department should pay attention to transmission congestion and eliminate congestion through deploying various physical or financial means, in order to optimize generating resources and increase the market efficiency in the whole network.

Finally, the use of controllable lines offers different approaches for modeling the network and treating the control parameters. In the case that problem reduces to the standard model with the line impedances set to the pre-contingency values. In the case of controllable lines that can maintain flow during a contingency, there is a natural interpretation of the equivalent effect of the controllable line as to create fixed net loads at each end of the line and remove the representation of the line in the network model. In general, the price of energy delivered over a controllable line would be greater than or equal to the price of power generated at the point of delivery and could be higher than the price of energy injected at the source of the controllable line but flowing over the open ties if the outage of the controllable line were not a binding contingency. If the outage of the controllable line were the only binding contingency, then price of energy delivered over the controllable line would be less than the price of power delivered from a generator at the delivery point and less than or equal to the price of energy injected at the source of the controllable line were one of two or more binding contingencies, the price of power delivered over the controllable line could be less than or greater than the price of power delivered from a generator at the delivery point. The other key factor influencing the pricing of energy scheduled to flow over controllable lines is whether the outage of the controllable line is a binding contingency in the ISOs security analysis. In the circumstance in which the outage of the controllable line is the only binding transmission constraint and contingency, then the total level of transfers does not depend on the schedules over the controllable line. Instead, the total level of transfers is determined by the pattern of transmission flows in the contingency in which flows over the controllable line are zero. In this circumstance as incremental variations in the pre-contingency schedules over the controllable line do not affect the cost of meeting load and there is no need for a price signal to incent pre-contingency schedules over the controllable line. It still could be the case that the operation of the controllable line increases total transfer capability and thus contributes to congestion rents. If the outage of the controllable line were not the binding contingency or were not the only binding constraint or contingency, then the total level of transfers and production costs would depend on the amount of energy scheduled to flow on the controllable line and optimal scheduling of flows on the controllable line would require a distinct price signal for those schedules. In these circumstances the value of energy delivered over the controllable line could, in principle, range from being equal to the value of power delivered over the AC interconnect to having a value greater than that of energy injected by a generator at the delivery point of the controllable line.

7.2 Future Work

The following is a partial list of interesting future developments for our work:

- Increase complexity in system simulation – This will allow for bigger systems with more elements added to them. It will also allow us to increase the number of cases and situations being studied. In addition more positive changes might come from this even thou it will require more time and as a result. For example, It will be beneficial to increase transformers to the simulation to make the system look more representative of how more practical systems might look and be able to work at other types of voltages and not just one and see if any effect come from this situation.
- Include Losses into system analysis model– This will help improve the reliability and credibility of the simulation as well as the overall performance of the system. This is something that most of the electric power markets don't take into consideration in there calculations and some are starting to include now. In addition, it will make it unique and will definitely interest national electricity markets in general. However, it will increase the difficulty of the study but will provide a good reward.
- Analysis with phase shifter as controllable element– This will add another side to the investigation and will benefit the project because it will allow the chance to compare the results obtained by each option and determine which one is better. It

helps us to see and differentiate the strength and weaknesses of both of controllable elements used. In the end, what it will help us is to see if they are a better option than connecting series capacitors to the transmission lines.

- Analysis with multiple controllable lines – Increase the complexity of the study controlling multiple lines in the system at the same time or different times with pre- and post-congestions or contingencies. Study the
- Explore additional software- This will help to compare the results from the ones obtained in Power World and see if they are reliable. In other words, how much error or percent of difference they have. It will also help us to eliminate the limitations provided by the current software. For example, improve the model of all of the elements provided by the software to simulate the system. Also, have additional data parameters that will help us analyze and see if the results are positive. Finally, a software that is more easy to use, with quicker response and better way of finding the results.
- LMP with distributed slack bus- The reference for shift and loss factors does not have to be located at a particular physical bus. If a distributed slack bus was selected, participating factors for each bus can be assigned to cover for imbalance in the system. Let us use distributed bus with the load-weighted participating factors. Let us distribute losses among all load buses as well.

REFERENCES

1. Daniel S. Kirschen, and Goran Strbac, "Fundamentals of Power System Economics," *John Wiley*, pp. 141-204, 2004.

2. H. He, Z. Xu, "Transmission Congestion and its Social Effects," *IEE PES.*, vol. 1, pp. 350-354, June 2005.

3. H. He, Z. Xu. and G.H. Cheng, "Impacts of Transmission Congestion on Market Power in Electricity Market," *IEE PES*, vol. 1, pp. 190-195, October 2004.

4. Antonio J. Conejo, Enrique Castillo, Roberto Mínguez, and Federico Milano, "Locational Marginal Price Sensitivities," *IEEE PES*, vol. 20, pp. 2026-2033, November 2005.

5. G. Hamoud and I. Bradley, "Assessment of Transmission Congestion Cost and Locational Marginal Pricing in a Competitive Electricity Market", *IEEE PES,* vol. 19, pp. 769-775, May 2004.

6. Eugene Litvinov, "Power System & LMP Fundamentals," ISO New England Inc. 2008.

7. Eugene Litvinov, "Power System and LMP Fundamentals", *2008,* ISO New England Inc., May 14, 2008 <http://www.iso-ne.com/support/training/courses/lmp301/index.html>.

8. Tong Wu, Ziad Alaywan, and Alex D. Papalexopoulos, "Locational Marginal Price Calculations Using the Distributed-Slack Power-Flow Formulation," *IEE PES*, vol. 20, pp.1188-1190, May 2005.

9. Zhaoqiang Ge, Minhui Ge, Libing Yang and Dexing Wang, "Locational Marginal Price of East China Electric Power Market," *IEEE PES,* pp. 214-217, April 2008.

10. Alberto Ramirez Orquin and Vanessa Ramirez, “Addressing Grid Issues in Transitional Deregulated Systems,” *IEE PES*, pp. 198-205, October 2005.

11. Santosh Raikar and Marija Ilic, “Assessment of Transmission Congestion for Major Electricity Markets in the US,” *IEEE PES* vol. 2, pp. 1152-1156. July 2001.

12. Lisa Cameron and Peter Cramton, “The Role of the ISO in U.S. Electricity Markets: A Review of Restructuring in California and PJM”, *Electricity Journal,* pp. 71-81, April 1999.

13. William W. Hogan, “Notes on Controllable Line Pricing”, *Day-Ahead Market Study,* pp. 1-6, May 2001.

14. William W. Hogan, “Appendix: Controllable Lines”, *Day-Ahead Market Study,* pp. 1-31, May 2001.