A NEW METHOD FOR LOCATIONAL MARGINAL PRICING

A DISSERTATION

Submitted in partial fulfilment of the requirements for the award of the degree of

MASTER OF TECHNOLOGY

in

ELECTRICAL ENGINEERING

(With Specialization in Power System Engineering)

By

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CANDIDATE'S DECLARATION

I hereby declare that the work presented in this dissertation entitled **"A New Method For Locational Marginal Pricing"** submitted in partial fulfillment of the requirements for the award of the degree of Master of Technology with specialization in Power System Engineering in the Department of Electrical Engineering, Indian Institute of Technology Roorkee, Roorkee is an authentic record of my own work carried out from July 2004 to June 2005 under the guidance of **Dr. N.P.Padhy**, Assistant Professor, Department of Electrical Engineering, Indian Institute of Technology Roorkee, Roorkee and **Dr. R.N.Patel,** lecturer, Department of Electrical Engineering, Indian Institute of Technology Roorkee, Roorkee.

I have not submitted the matter embodied in this report for the award of any other degree or diploma.

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CERTIFICATE

This is to certify that the above statement made by the candidate is true to the best of my knowledge and belief.

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ABSTRACT

The electricity market around the world has undergone major structural change for the past few years thus creating competition. This resulted in unbundling of the vertically integrated utilities such as generation, distribution and retailing. Due the large economies of scale, transmission is a natural monopoly in most countries. As the trend of the electrical industry is heading towards more Open Transmission Access, transmission is on its way to integrate onto the unbundling process to ensure fair and non-discriminatory transmission access. Efficient pricing in transmission service plays an important role that it is necessary to send correct economic signals to transmission users relating to operation of existing capacity, investment in new capacity and forecasted demand.

This thesis introduces Available Transfer Capability and proposes Locational Marginal Pricing method including voltage stability constraints in competitive electricity markets and pricing system security.

A multi-objective Optimal Power Flow (OPF) approach to account for system security through the use of voltage stability constraints is proposed and solved by means of an Interior Point Method Nonlinear Programming technique, so that the social benefit and the distance to a maximum loading condition are maximized at the same time.

Locational marginal prices and nodal congestion prices resulting from the proposed method as well as comparisons with results obtained by means of standard techniques currently in use for solving electricity market problems are presented and discussed.

The proposed method is tested on simple test system and on an IEEE 30-bus system considering supply side bidding. Results were obtained using MATLAB 6.0.

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CHAPTER-1

INTRODUCTION AND LITERATURE REVIEW

1.1 MOTIVATION

In recent years, the electricity industry has undergone drastic changes due to a world wide deregulation/privatization process that has significantly affected power system management and energy markets. In a deregulated system, operators' goals are balancing consumer power demand using the available generation and ensuring that economical and technical constraints are respected. The prime economical aspect is the social benefit, i.e. power suppliers should obtain maximum prices for their produced energy, while consumers should pay the lowest prices for the purchased electric power. Prices have to be defined in a free market economy and restricted only by power exchange rules.

Among the several competitive market models which have been proposed, the following four basic models have been widely accepted and utilized in practice [1]:

Model 1 Wholesale generators provide power supply bids to a single pool; then Load-serving companies buy wholesale power from the pool at a regulated price and resell it to retail loads.

Model 2 Wholesale generators and load-serving companies provide power supply and demand bids to a single pool; then load-serving companies resell Wholesale power to retail loads.

Model 3 Combinations of models 1 and 2 with bilateral wholesale contracts between generators and load-serving companies.

Model 4 Combinations of all previous plus contracts between all participants and retail loads.

Regardless to the adopted market model, the prime physical constraint is that power supply and demand has to be balanced in real time by scheduling the most economic generation on a fixed time horizon basis (e.g. a day ahead). In a deregulated environment, the balance is obtained by means of a primary electricity market which supplies the scheduled demand.

Furthermore, independent market operators and market participants require a minimum level of quality and system security, i.e. the available power and control systems have to be able to balance the actual load demand in case of first class contingencies, minimize the negative effects of outages and maintain voltages and frequency within their security limits. Thus there is the need of stability studies in order to maintain the desired security level. The latter is generally improved avoiding or limiting as much as possible system Congestions caused by transmission system constraints. Observe that congestions affect both security and market transactions. As a matter of fact, several studies propose criteria for pricing congestions and fairly sharing costs among the right market entities [2].

Congestion constraints such as thermal limits on transmission lines, or voltage levels, although should be avoided, do not lead to immediate emergency conditions, and thus optimization methods applied in reality and/or proposed in the literature, generally take advantage from this practical consideration and focus more on computational efficiency than security constraints, in order to be tailored for on-line applications [2, 3]. However, congestions associated with voltage collapse phenomena may have severe and immediate consequences on system stability, but voltage collapse issues are seldom associated with competitive market studies [4, 5].

Voltage collapse has the following characteristics:

1. It is a catastrophic and sudden phenomenon and has typically severe effects on some network areas and, sometimes, even on the entire grid. Thus precise information about the proximity to voltage collapse is needed.
2. It is generally induced by heavy loading conditions and/or outages which limit the power transfer capability.
3. A detailed nonlinear analytical model of power system is required to properly study voltage collapse phenomena. This is in contrast with the need of computational efficiency of methods accounting for security and economic dispatch.

With past and current difficulties in building new transmission lines and the significant increase in power transactions associated with competitive electricity markets, maintaining system security, with special regard to voltage instability/ collapse issues, is more than ever one of the main concerns for market and system operators.

Hence, there is the need for pricing this security in a simple, unambiguous and transparent way, so that the "right" market signals can be conveyed to all market participants. However, pricing security is not an easy task, since it involves a variety of assumptions as well as complex models and simulations. In the four main market models that have been described above, how to properly include and price system security is still an open question.

1.2 OBJECTIVE OF THE WORK

The following areas of current interest will be addressed in OPF-based electricity market and pricing electricity studies with inclusion of detailed voltage stability constraints:

1. Develop an algorithm to determine the feasibility of transaction using repeated power flow method.
2. Development of a Voltage Stability Constrained (VSC) OPF-based electricity market. To be a flexible tool for operators, the VSC-OPF should be able to provide market solutions with a desired level of security.

Thus, this thesis investigates the effects of voltage stability constraints on competitive market model, and provides a technique able to evaluate the weight of security on electricity prices.

1.3 AUTHOR'S CONTRIBUTION:

The main contributions of this thesis can be summarized as follows:

1. Development of an algorithm to determine the feasibility of the bilateral transaction.
2. Development of a multi-objective stability constrained OPF for solving electricity market with the ability of tuning the desired security level.
3. Definition of Locational marginal prices and nodal congestion prices which take into account voltage stability constraints and properly price the congestion status of the current bid profile.

1.4 LITERATURE REVIEW

This thesis mainly focuses on competitive electricity markets and on the inclusion of proper security constraints through the use of an Optimal Power Flow (OPF)-based approach, whose ability to solve practical power system problems has been widely recognized [6, 7 and 8].

Ejebe [9] give the detailed formulation and implementation of a fast program for power system available transfer capability calculations in which the formulation is based on the linear incremental power flow is given. Toyoda [10], Liam Murphy [11] and Luonam Chens [12] give the concept of nodal prices. Luonam Chens [12] split the Locational marginal prices into a variety of parts corresponding to concerned factors, such as generations, transmission congestion, voltage limitations and other constraints.

Lu and Unum [13] proposed several strategies for an OPF with active power dispatch and voltage security, which was represented only by voltage limits. Most of the methods proposed in the literature used a logarithmic barrier Interior Point Methods (IPMs) for solving the OPF problem [14, 15 and 16]. IPMs proved to be robust, especially in large networks, as the number of iterations increase slightly with the number of constraints and network size. However, early implementations of IPM for solving market problems, accounting somewhat for system security, were limited to the use of linear programming.

Madrigal, Quintana [17] and Torres [18] present a comprehensive investigation of the use of IPM for nonlinear problems, and describe the application of Merhotra's predictor corrector to the OPF, which highly reduces the number of iterations to obtain the final solution. Non-linear optimization techniques have also been shown to be adequate for addressing a variety of voltage stability issues, such as the maximization of the loading parameter in voltage collapse studies, as discussed in [4], [5], [17], [19] and [20]. Torres [18] and El-Keib [21] applied non-linear IPM techniques to the solution of diverse OPF market problems.

Rosé hart, Canizares, and Quintana [5] proposed a technique to account for system security through the use of voltage stability based constraints in an OPF-IPM market representation, so that security is not simply modeled through the use of voltage and power transfer limits, typically determined off-line, but it is properly represented in on-line market computations. In the current thesis, a multi-objective approach similar to the one proposed in [17] is used in an OPF-IPM market model, so that the social benefit and the distance to a maximum loading condition are maximized at the same time. In this way, voltage stability concepts and techniques are used to improve power transactions and the representation of system security [5].

Besides the ability of including a variety of security constraints, OPF-based market models allows defining precise price indicators, based on spot pricing techniques [2]. Spot pricing was originally defined for active power transactions, considering only congestion alleviations [2], and then extended to account for different price components, such as reactive pricing and ancillary services [2, 22].

The utilization of spot pricing concepts with OPF-based market models is currently a well accepted theory and is based on the decomposition of Lagrangian multipliers associated with power flow equations into the sum of two terms, i.e. costs of generation and losses and costs of system congestions [23]. In this thesis an integrated optimal spot pricing model is mostly based on the technique described in [24] and used to evaluate costs associated with the voltage stability constraints introduced in the OPF problem.

1.5 OUTLINE OF THE THESIS

This thesis is organized as follows:

Chapter 2 introduces available transfer capability to determine the feasibility of the bilateral transaction and develops algorithm to calculate the available transfer capability. Chapter 3 defines Locational marginal pricing and explains the same with examples. Chapter 4 describes OPF-based market clearing mechanism problems and electricity pricing techniques which have been proposed in the literature and are used as background for the method developed in this thesis.

The proposed single-period, multi-objective voltage stability constrained OPF problem is fully described in Chapter 5 paying particular attention to the determination of electricity prices.

In Chapter 6 a variety of test system examples are solved to properly illustrate the proposed technique and demonstrate their reliability also for realistic size problems.

Finally, concluding observations along with possible future research directions are presented in Chapter 7, whereas network and market data for all test cases used in this thesis are reported in Appendix A.

CHAPTER-2

FEASIBILITY ASSESSMENT OF WHEELING TRANSACTIONS

2.1 INTRODUCTION

All the transactions need to be evaluated ahead of their scheduling time to check their feasibility with regard to the system conditions at the time of scheduling. ISO would have to honor and execute only those proposed transactions as far as the system design and operating conditions permit. So before we go for cost analysis, it is important to analyze the feasibility of all proposed firm transactions for a particular transmission network under prevailing system constraints. Only after passing the feasibility test the proposed firm transactions are scheduled for dispatch. This analysis will be required not only by ISO, but also by the end users of the systems to make proper decisions regarding the generations and loads to be connected at different buses of the power system.

A transaction is deemed to be feasible if it can be accommodated without violating any of the system operating constraints such as equipment ratings, transmission interface limits, voltage limits etc. The feasibility of a single bilateral transaction can easily be determined from the available transfer capability (ATC) of the network between the buses where a transaction enters and leaves the network. ATC is a measure of the transfer capability remaining in the physical transmission network for future commercial activity over and above already committed uses. Transfer capability evaluation is a very wide area of research. Extensive work has already been carried out in this direction and more research is in progress in this field in order to increase its accuracy considering various factors and margins. The transfer capability has been defined in the literature in many ways depending upon the requirements and accuracy required for a particular analysis. It may be defined as amount of power, incremental above normal base power transfers, that can be transferred over the transmission network, with all facility loading are within normal ratings and all voltages are within normal limits. Available transfer capability is required to be posted on Open Access Same-Time Information System (OASIS). The generation-load pair can make reservation for bilateral transaction whose size should be less than ATC between the points where transaction enters and leaves the system. After including one transaction in the system, ATC between all the buses changes and revaluated. Same procedure is repeated for second transaction. Similarly all the feasible bilateral transactions are added to the system one by one. But this procedure cannot be applied to simultaneous bilateral and multilateral transactions. Because the transfer capability of a transaction in a group of simultaneous transactions will depend upon the order in which the transactions are considered to be added to the transmission network.

The main aim is to develop algorithm for assessment of the feasibility of the simultaneous bilateral and multilateral transactions and if they are not feasible then to find out the minimum amount of transacted power to be curtailed in order to make them feasible. This analysis will be a great help for the generation-load pairs to decide whether to withdraw the unfeasible transaction completely or to make it feasible by reducing its size optimally. An efficient, repeated Newton-Raphson power-flow based algorithm is developed to determine transfer capability and hence feasibility for single bilateral transaction.

2.2 MATHEMATICAL FORMULATION

Let there be nbt number of bilateral transactions and a transaction t is from bus i to bus j.

Let Pg_i^t be generation (in addition to base case) at bus I and Pd_j^t is load (in addition to base case) at bus j for a transaction t. Base case means already committed generations, loads and transactions on transmission network.

Let Ts^t be size of each proposed bilateral transaction t.

So Ts^t is equal to Pd_j^t, considering transmission losses for the transaction being provided by the utility or pool. The generation-load pairs of the transaction are charged for these losses.

Let there is nmt number of groups of multilateral transactions.

Let PMT^k be the size of kth group of multilateral transaction.

Let there be ngk number of generation points and ndk number of demand points for a group k.

It may be noted that 'ngk' may or may not equal to ndk.

Let Pgm_i^k be the generation at a generation point i of multilateral transaction k.

Let Pdm_i^k be the load at a load point i of multilateral transaction k.

The objective is to maximize total power transfer PT .

$$PT = \sum_{h=1}^{nbt} Ts^t + \sum_{k=1}^{nmt} PMT^k \tag{2.1}$$

Subject to the following constraints

(i) The bilateral transaction constraint

$$Pg_i^t = Pd_j^t \tag{2.2}$$

for all bilateral transactions.

(ii) Bilateral transaction size constraints

$$Ts^t \le Ts_m^t \tag{2.3}$$

For all bilateral transactions

Where Ts_m^t is maximum proposed size of transaction t.

(iii) Multilateral transaction constraints

$$\sum_{j=1}^{ndk} Pdm_j^k = \sum_{i=1}^{ngk} pgm_i^k = PMT^k \tag{2.4}$$

(iv) Multilateral transaction generation and load constraints

$$Pgm_i^k \le Pgmp_i^k \tag{2.5}$$

$$Pdm_j^k \le Pdmp_j^k \tag{2.6}$$

Where, $Pgmp_i^k$ is the proposed generation at generation point i of group k of multilateral transaction.

$Pdmp_j^k$ is the proposed load at load point j of group k of multilateral transaction.

(v) The power flow equation of the power network

$$g(V,\phi) = 0 \tag{2.7}$$

Where

$$g(V,\phi) = \begin{cases} P_i(V,\phi) - P_i^{net} & , for\ each\ PQ\ bus\ i \\ Q_i(V,\phi) - Q_i^{net} & , for\ each\ PQ\ bus\ i \\ P_m(V,\phi) - P_m^{net} & , for\ each\ PV\ bus\ m, not\ including\ the\ reference\ bus \end{cases}$$

Where

P_i and Q_i are respectively calculated real and reactive powers for PQ bus i.

P_i^{net} and Q_i^{net} are respectively specified real and reactive powers for PQ bus i.

P_m and P_m^{net} are respectively calculated and specified real power for PV bus m.

V and ϕ are voltage magnitude and phase angles of different buses.

(vi) The inequality constraint on reactive power generation Qg_i at PV buses

$$Qg_i^{min} \le Qg_i \le Qg_i^{max} \tag{2.8}$$

Where Qg_i^{min} and Qg_i^{max} are respectively minimum and maximum value of reactive power generation at PV bus i.

(vii) The inequality constraint on voltage magnitude V of each PQ bus

$$V_i^{min} \le V_i \le V_i^{max} \tag{2.9}$$

V_i^{min} and V_i^{max} are respectively minimum and maximum voltage at bus i.

(viii) The inequality constraint on phase angle ϕ_i of voltage at all the buses i

$$\phi_i^{min} \le \phi_i \le \phi_i^{max} \tag{2.10}$$

Where

ϕ_i^{min} and ϕ_i^{max} are respectively minimum and maximum allowed value of voltage phase angle at bus i.

(ix) Power limit on transmission line

$$MVAf_{ij} \le MVAf_{ij}^{max} \tag{2.11}$$

Where

$MVAf_{ij}^{max}$ is the maximum rating of transmission line connecting bus i and j.

2.3 ASSESSMENT OF AVALAIBLE TRANSFER CAPABILITY

The feasibility of a single bilateral transaction can easily be determined from the ATC of the transmission network between the buses, where the transaction enters and leaves the network.

2.4 REPEATED POWER FLOW (RPF) METHOD

Let IL is a scalar parameter representing the increase in the load as well as generation above base case. IL=0 corresponds to no transfer (base case) and $IL=IL_{max}$ corresponds to maximum transfer. IL is to be maximized by giving small increments

ΔP in steps, subject to all transmission network constraints mentioned in equations (3). ATC between any two buses of the network is the maximum value of IL satisfying all system constraints. The below figure 2.1 is the flow chart for detailed procedure of RPF method.

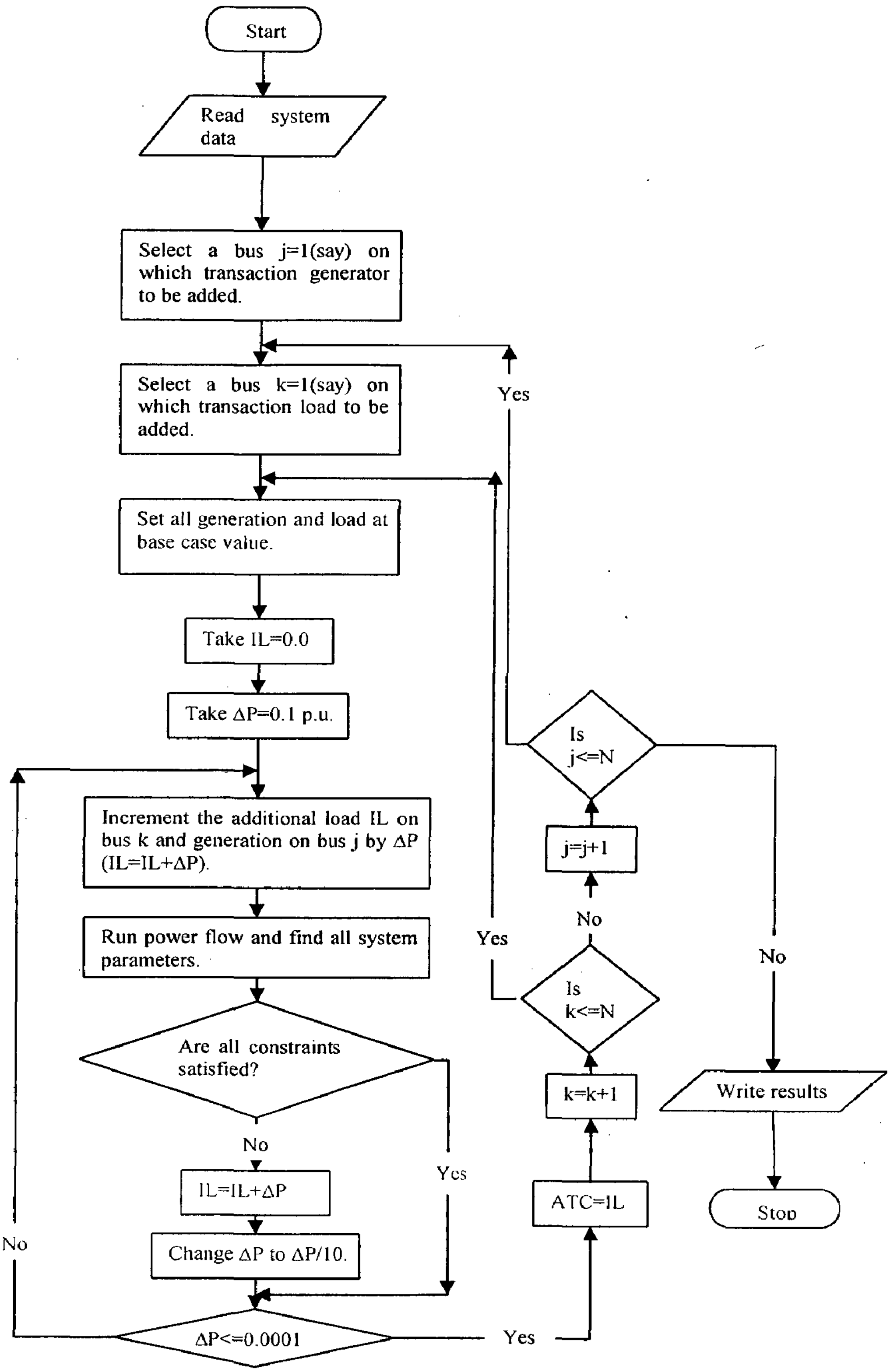

Figure 2.1: Flow chart for determination of ATC by RPF method

CHAPTER-3

LOCATIONAL MARGINAL PRICING

3.1 INTRODUCTION

Locational Marginal Pricing (LMP) is based on actual flow of energy and actual system operation which is a voluntary bid-based, economical dispatch market that determines electricity and transmission congestion prices at specific nodes based on marginal generation costs. LMP is a model that determines optimal generation dispatch and electricity & transmission congestion prices at different locations. LMP's purpose is to determine the delivered electricity price at a specific location by calculating and accounting for the relevant electricity and transmission congestion prices. Generally, LMP determines the electricity price for each node on the grid as well as calculating the transmission congestion price (if any) to serve that node. For the above reason, LMP is often referred to as "Nodal Pricing". The Locational Marginal Price at a specific location is the sum of the cost of generating the next MW to supply load at a specific location (based on marginal generation cost, the cost of transmission congestion, and the cost of losses). Therefore, the LMP is formed:

LMP = Generation Marginal Price + Transmission Congestion Price + Cost of Loss

There are various arguments against this method, It lacks pricing transparency, high transaction cost, regulated and unregulated services are needlessly bundled; a possibility of manipulating the system if transmission (a regulated service) is bundled with generation, susceptible to market power abuse; if a horizontal concentration in generation is capable of manipulating the exchange price and lastly it doesn't provide incentive to construct generation or transmission; LMP may in certain instances provide incentive to avoid the construction transmission in order to maximize congestion revenue.

There are several dispatch techniques for alleviating transmission system congestion. In such systems, optimization is performed to alleviate congestion. The objective of such optimization is to minimize the bid based price of meeting power demand while enforcing transmission system constraints. The use of Locational Marginal Pricing provides a useful solution of pricing the congestion rescheduling actions that are performed. The basic definition of LMP is `the minimum price of supplying an additional MW of load at each location (bus) of the system. The major factors affecting the marginal prices or costs are the generator bid prices, the system operator dispatch, the transmission system elements that are experiencing congestion, any transmission constraints, the losses on the system, and the electrical characteristics of the system. Such marginal costs would explicitly account for congestion and would therefore differ by location whenever the network is constrained. Generators are paid for the electricity they supply to the market, according to the LMP at their point of connection to the system. Electricity Consumers (load) buy the electricity they consume based on the LMP at their connection point. Bilateral transactions pay a congestion charge that is based on the difference in the LMPs between the delivery point of the transaction and the receipt point. Transactions into or out of the system will pay congestion charges based on their entry or withdrawal point.

3.2 Unconstrained LMP Example

In this example, an increase in load does not causes transmission congestion so the lowest bid generator can be used to meet the load, assuming that the generator is capable of doing so. Re-dispatch is not necessary to serve the load. All requests for transmission to serve the load from the lowest bid generator can be accommodated.

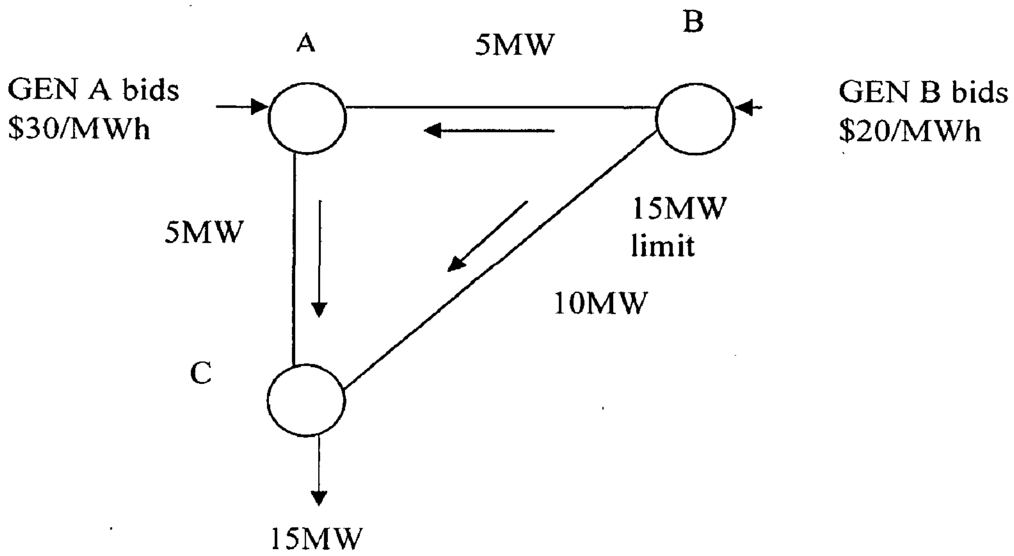

Figure3.1: Unconstrained LMP Example 1

Figure 3.1 show the load on this system is 15MW at Node C and Generator B at Node B is capable of generating at least 15MW. Generator B will be the exclusive supplier, the power flow on the line B-C is 10MW, hence did not violate the 15MW limit. The remaining 5MW will flow from B-A and A-C. Hence no resultant congestion and LMP at the load would be $20/MWh. What if the demand increases from 15MW to 21MW as shown in Figure 3.2?

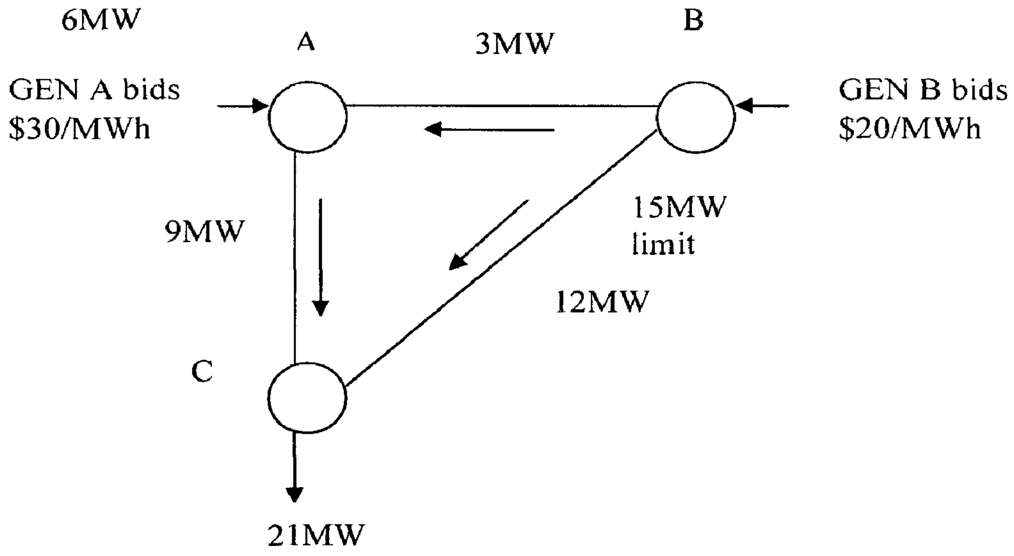

Figure3.2: Unconstrained LMP Example 2

Assuming Generator B's capacity limit is capable of producing only 15 MW. Therefore Generator A would need to dispatch 6 MW to meet the demand load. There is still no sign of congestion, since the total power flow along the line B-C does not violate the 15MW limit. The LMP at the load would be $30MW/h, the price of the last MW dispatched. This is price is thus known as "Market Clearing Price".

3.3 Constrained LMP Example

In this example, an increase in load causes transmission congestion so the lowest bid generator cannot be dispatched to its full capacity. A Re-dispatch is necessary to serve the load without violating the transmission line constraint. This example will illustrate using a 3-bus system model shown in Figure 3.3 and Figure 3.4 to demonstrate LMP methodology. The data for the 3- bus system (Generator's bids and capacity and load demand) is given in Table 3.1 and Table 3.2.

Table 3.1: List of Generators' Bids and Capacity

Bus	Market Participant	MWh Available	Offer Price
1	Generator 1	70MWh	$3/MWh
1	Generator 2	100MWh	$3/MWh
2	Generator 3	120MWh	$4/MWh

Table 3.2: List of Loads' Demand

Bus	Market Participant	MWh Demand
3	Load 1	110MWh
3	Load 2	120MWh
2	Load 3	20MWh

The lowest-bid generator would be first dispatched if it can be used to meet the load. Generator 1 and Generator 2 at the Bus 1 can supply a maximum total of 170MW at $3/MWh; Generator 3 at Bus 2 can supply a maximum total of 120MW $4/MWh. The total demand load is 250MW.

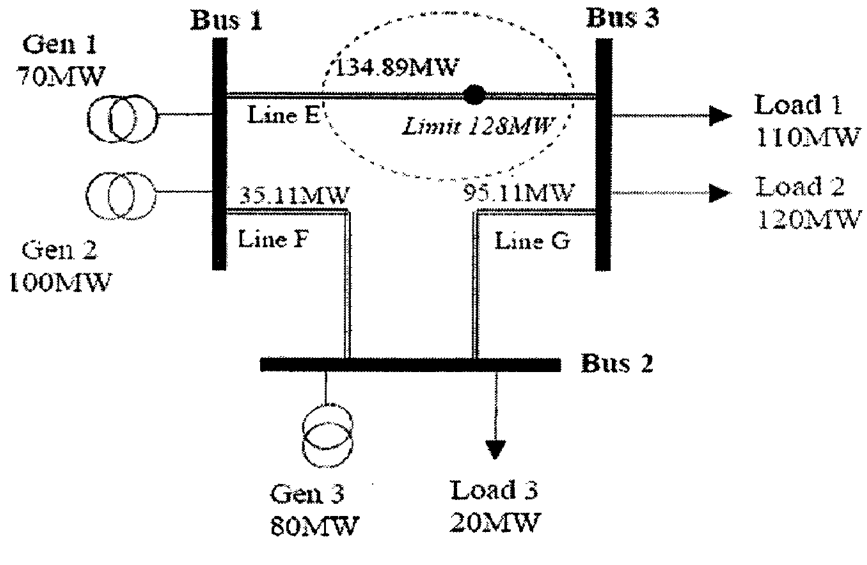

Figure 3.3: Constrained 3-Bus System Example 1

Considering lowest bid generator can be used to meet the load, Generator 1 and Generator 2 at Bus 1 are capable of supplying the entire 170MW and Generator 3 supply at 80MW to accommodate the demand of 250MW. However it could not do so without exceeding the limit on the transmission line. This dispatch is hence not feasible because it violates the 128MW thermal limit. In order not to exceed the constraint, a re-dispatch would need to be performed so Generator 2 is decrease to supply at 80MW instead of 100MW and Generator 3 increase to supply from 80MW to 100MW.

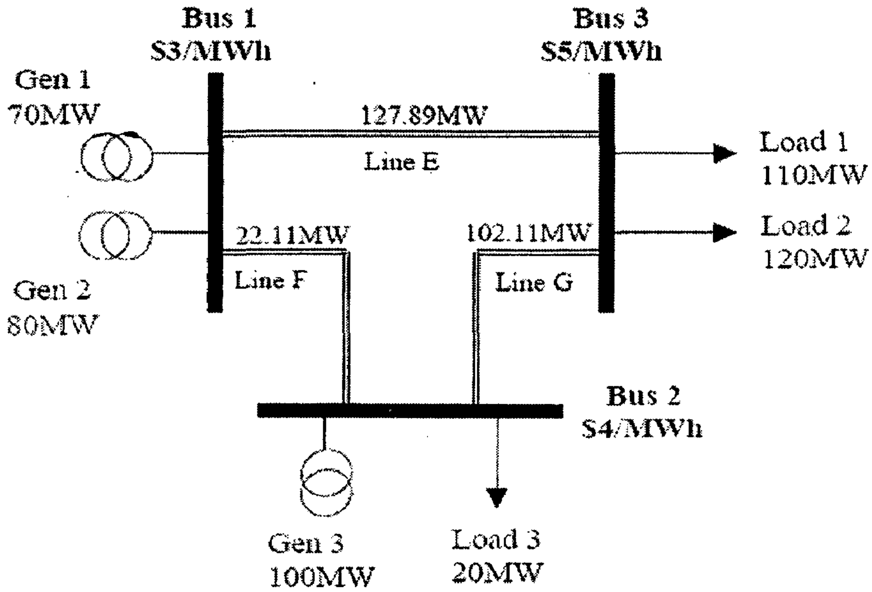

Figure 3.4: Constrained 3-Bus System Example 2

In this situation, we call it constrained condition; LMPs vary by node and can be higher than any generator bid. For every 1MW of increased load at Bus 3, in order not to exceed the limit, Generator 3 must be increased to 2MW and Generator 2 decreased by 1MW. For this reason the LMP is calculated to be $5/MWh (2MW x $4/MWh - 1MW x $3/MWh) at Node 3 which is higher than the generator bids. As for Load 3 at Bus 2, it remains as $4/MWh since the load can be met by dispatching Generator 3 (within the capability of the generator).

Table 3.3: Table of Generation Revenue

Market Participant	Generation	Generation LMP	Generation Revenue
Generator 1	70MW	$3/MWh	$210/MWh
Generator 2	80MW	$3/MWh	$240/MWh
Generator 3	100MW	$4/MWh	$400/MWh

Table 3.4: Table of Demand Payment

Market Participant	Demand Load	Demand LMP	Demand Payment
Load 1	110MW	$5/MWh	$550/MWh
Load 2	120MW	$5/MWh	$600/MWh
Load 3	20MW	$4/MWh	$80/MWh

Table 3.5: Net bill Collected by the Utility

	Gen 1	Gen 2	Gen 3	Load 1	Load 2	Load 3	Net Bill
Revenue	- $210	- $240	- $400	+ $550	+ $600	+ $80	$380

Table 3.3 shows the LMPs at the generators and their revenue. The net bill collected from the Utility is $380. It can observe from Table 3.4 and Table 3.5 that the Load 1 and Load 2 made up most of the revenue collected by the Utility because of their high LMP $5/MWh. It can therefore be assumed that Load 1 and Load 2 bear the most the most or perhaps the full transmission cost in the context of constraint circumstances. In actual practice, all applicable customers on the grid pay an average energy rate, with no direct assignment of the costs of transmission congestion.

CHAPTER-4

OPTIMAL POWER FLOW OUTLINES

4.1 INTRODUCTION

With regard to the solution of the electricity auction problem, two main approaches are currently under study in the literature: merit order or single-price auctions and OPF-based power markets. The basic principles of single-price auctions have been implemented by many Independent Market Operators (IMO) all around the world. Market clearing procedures currently in use in competitive pool-based electricity markets differ significantly from one another. However, some common characteristics can be recognized, as follows:

1. Merit order market clearing mechanisms are simple, transparent and well accepted by market participants;
2. There is the need of separate procedures to take into account losses, congestions and, in general, nonlinear constraints;
3. Linear Programming (LP) and/or Mixed Integer Programming (MIP) techniques used to solve merit order market problems have a high computational efficiency, which is needed for on-line applications).

Since in this thesis the main interest is including voltage stability constraints in the market problem, the second point is the main drawback of simple auction techniques. Thus, we will focus only on Optimal Power Flow (OPF) based hybrid markets. Generally speaking, OPF methods are not strictly related to market problems. As a matter of fact, OPF methods have been used in regulated power systems to schedule power generations in order to minimize cost productions and losses in transmission lines. OPF main characteristics are as follows:

_ OPF may include a variety of (nonlinear) constraints, thus allowing for precise power system models;

_ OPF is not very popular among market operators because of its complexity and "obscure" solution process;

_ OPF does not need separate procedures to take into account losses and transmission congestions;

_ Low efficiency of solvers for Nonlinear Programming (NLP) is a critical issue for on-line applications. This chapter introduces firstly the nomenclature utilized throughout this thesis for the formulations of the OPF problems; The OPF-based approach to maximize the distance to voltage collapse is also discussed since it provides the basic approach to include voltage stability constraints in the OPF-based market mechanisms proposed in this thesis.

4.2 NOMENCLATURE FOR THE OPF-BASED MARKET PROBLEM

Constants:

$P_{S\max i}$	Upper limit of the energy bid offered by unit i[MW];
$P_{S\min i}$	Lower limit of the energy bid offered by unit i[MW];
$Q_{G\max i}$	Upper limit of the reactive power support available at unit i [MVar];
$Q_{G\min i}$	Lower limit of the reactive power support available at unit i [MVar];
T	scheduling time horizon (e.g.24 hrs);
$P_{D\max j}$	Upper limit of the energy bid demanded by consumer j [MW];
$P_{D\min j}$	Lower limit of the energy bid demanded by consumer j [MW];

Variables:

$P_{Si}(t)$	Power output of generation unit i in period t [MW];
$\overline{P}_{Si}(t)$	Maximum power output of generation unit i in period t [MW];
Q_{Gi}	Reactive power output of unit i [MVar];
$P_{Di}(t)$	Power output of consumer j in period t [MW];
$u_i(t)$	0/1 variable which is equal to 1 if unit i is online in period t;
$w_i(t)$	0/1 variable which is equal to 1 if unit i is started up at the beginning of period t;
$z_i(t)$	0/1 variable which is equal to 1 if unit i is shut-down at the beginning of period t;

Sets:

I	set of indexes of generating units;
J	set of indexes of consumers;
T	set of indexes of periods of the market horizon;
B	set of indexes of network buses;
N	set of indexes of transmission lines;

4.3 OPF-BASED ELECTRICITY MARKET

Single-period OPF-based approach is basically a nonlinear constrained optimization problem, and consists of a scalar objective function and a set of equality and inequality constraints. The objective function is typically maximizing the social benefit, i.e. ensuring that generators get the maximum income for their power production and consumers or wholesale retailers pay the cheapest prices for their power purchase as follows:

$$Max.\ \ G = \sum_{j \in J} c_{Dj}(P_{Dj}) - \sum_{i \in I} c_{Si}(P_{Si}) \tag{4.1}$$

Where c_S and c_D are generic but monotonic generator and consumer cost functions of power bids P_S and P_D. In this thesis c_S and c_D will be considered linear functions of powers, without losing generality:

Power flow equations:

$$\mathrm{P_h} = \mathrm{V_h}^2(\mathrm{g_h} + \mathrm{g_{h0}}) - \mathrm{V_h}\sum_{l \neq h}^{n_l} V_l(g_{hl}\cos(\theta_h - \theta_t) + b_{hl}\sin(\theta_h - \theta_t)) \tag{4.2}$$

$$\forall h \in B$$

$$\mathrm{Q_h} = -\mathrm{V_h}^2(\mathrm{b_h} + \mathrm{b_{h0}}) + \mathrm{V_h}\sum_{l \neq h}^{n_l} V_l(g_{hl}\sin(\theta_h - \theta_t) - b_{hl}\cos(\theta_h - \theta_t)) \tag{4.3}$$

$$\forall h \in B$$

$$P_h = \sum_{i \in I_h}(P_{Gi0} + P_{Si}) - \sum_{j \in J_h}(P_{Loj} + P_{D0j}) \tag{4.4}$$

$$\forall h \in B$$

$$Q_h = \sum_{i \in I_h} Q_{Gi} - \sum_{j \in J_h} (P_{L0j} + P_{D0j}) \tan(\phi_{Di}) \qquad (4.5)$$

$$\forall h \in B$$

Where V and θ represent the bus phasor voltages. Load models in power flow equations f are assumed to be $P_G = P_{G0}+P_S$ and $P_L= P_{LO}+P_D$, thus accounting for a fixed amount of powers, i.e. P_{G0} and P_{L0} , for must-run generations, non-interruptible loads, etc. The aim of (4.2) to (4.5) is twofold. Firstly, the active and reactive power balance is ensured; then transmission losses are accurately modeled and taken into account.

Supply bid blocks:

$$P_{S\min i} \le P_{Si} \le P_{S\max i} \qquad \forall i \in I \qquad (4.6)$$

Demand bid blocks:

$$P_{D\min j} \le P_{Dj} \le P_{D\max j} \qquad \forall j \in J \qquad (4.7)$$

Generator reactive power support:

$$Q_{G\min i} \le Q_{Gi} \le Q_{G\max i} \qquad \forall i \in I \qquad (4.8)$$

Voltage "security" limits:

$$V_{\min h} \le V_h \le V_{\max h} \qquad \forall h \in B \qquad (4.9)$$

Thermal limits:

$$I_{hk}(\theta, V) \le I_{hk\max} \qquad \forall (h,k) \in N \qquad (4.10)$$

$$I_{kh}(\theta, V) \le I_{kh\max} \qquad (4.11)$$

Where I_{hk} and I_{kh} are the line currents and are used to model system security by limiting transmission line flows.

4.3.1 SECURITY CONSTRAINED OPF BASED ELECTRICITY MARKET

In common practice, the inclusion of system congestions in the OPF problem is obtained by imposing transmission capacity constraints on the real power flows, as follows:

Transmission congestion limits:

$$|P_{hk}(\theta, V)| \le P_{hk\max} \qquad \forall (h,k) \in N \qquad (4.12)$$

$$|P_{kh}(\theta, V)| \le P_{kh\max} \qquad (4.13)$$

Where P_{hk} and P_{kh} limits are obtained by means of off-line and/or voltage stability studies. In practice, these limits are usually determined based only on power flow based voltage stability studies. Hence, these limits do not actually represent the actual stability conditions of the resulting OPF problem solution, which may lead in some cases to insecure solutions and/or inadequate price signals. Summarizing and dropping the index notation, the standard security constrained OPF-based market model can be formulated as follows:

Social benefit

$$Max \quad C_D{}^T P_D - C_S{}^T P_S \tag{4.14}$$

s.t.

PF equations

$$f(\theta, V, Q_G, P_S, P_D) = 0 \tag{4.15}$$

Supply bid blocks

$$P_{S\min} \le P_S \le P_{S\max} \tag{4.16}$$

Demand bid blocks

$$P_{D\min} \le P_D \le P_{D\max} \tag{4.17}$$

Thermal limits

$$I_{hk}(\theta, V) \le I_{hk\max} \tag{4.18}$$

$$I_{kh}(\theta, V) \le I_{kh\max} \tag{4.19}$$

Congestion limits

$$|P_{hk}(\theta, V)| \le P_{hk\max} \tag{4.20}$$

$$|P_{kh}(\theta, V)| \le P_{kh\max} \tag{4.21}$$

Generation Q limits

$$Q_{G\min} \le Q_G \le Q_{G\max} \tag{4.22}$$

Voltage"security" limits

$$V_{\min} \le V \le V_{\max} \tag{4.23}$$

4.4 MAXIMIZATION OF THE DISTANCE TO VOLTAGE COLLAPSE

Rosé hart, Canizares, and Quintana [10] have been demonstrated that the following optimization problem:

$$Max \quad \lambda \tag{4.24}$$
$$\text{s.t. } f(x,\lambda)=0$$

In fact, the Lagrangian function associated with (4.24) can be written as:

$$L(x,\lambda,\rho)=\lambda-\rho^T f(x,\lambda) \tag{4.25}$$

ρ Being the Lagrangian multipliers, and the KKT optimality condition gives:

$$\frac{\partial L}{\partial x}=-\rho^T D_x f(x,\lambda)=0 \tag{4.26}$$

$$\frac{\partial L}{\partial \rho}=-f(x,\lambda)=0 \tag{4.27}$$

$$\frac{\partial L}{\partial \rho}=1-\rho^T\frac{\partial f}{\partial \lambda}=0 \tag{4.28}$$

Where Lagrangian multipliers ρ correspond to the elements of the left eigenvector $\hat{W}$. Model (4.24) can be extended in two main directions:

1. Adding inequality constraints to take into account voltage limits, generator reactive power limits, thermal limits, etc.
2. Modifying problem (4.24) to maximize the distance to voltage collapse instead of simply determining the collapse point.

Alsac, Bright, Prais and Stott [11] have been addressed the later issue for the first time and approached by using two sets of power flow equations, one for the current operating point and one for the "critical" solution associated with a voltage collapse condition or a security limit, as follows:

$$\begin{aligned}
Min. \quad & \lambda_p-\lambda_c \\
s.t. \quad & f(\theta_p,V_p,Q_{Gp},P_S,P_D,\lambda_p)=0 \\
& f(\theta_c,V_c,Q_{Gc},P_S,P_D,\lambda_c)=0 \\
& \underline{H}_p \le H(\theta_p,V_p,Q_{Gp}) \le \overline{H}_p \\
& \underline{H}_c \le H(\theta_c,V_c,Q_{Gc}) \le \overline{H}_c
\end{aligned} \tag{4.29}$$

Where H are constraint function of the dependent variables and $\underline{H}$ and $\overline{H}$ their lower and upper limits respectively and load models are assumed to be P_{G1} =

$(1+\lambda)(P_{G0}+P_S)$and $P_{L1}=(1+\lambda)(P_{LO}+P_D)$ Suffixes p and c indicate the current and the critical operating points, respectively, which solve the two sets of power flow equations. In (4.29) the distance to the maximum loading condition is certainly maximized because of the use of the two loading parameters λ_p *and* λ_c. The approach of doubling power flow equation and including the dependence on a loading parameter will be used in this thesis to formulate a voltage security constrained OPF.

4.5 OPTIMIZATION METHODS

There is a plethora of optimization methods used in power system analysis [14]. In this thesis, we are interested in method able to solve nonlinear programming since voltage stability constraints are best modeled with a set of (highly) nonlinear equations, while market and physical constraints are both continuous (power flow equations, transmission line flow limits, etc.). Approach and technique presented in the following subsection are chosen with the aim of both robustness and reliability for large problems.

4.5.1 NON-LINEAR PROGRAMMING PROBLEM

Nonlinear programming problems, which are typical in power-engineering and are suitable for solving optimal power flows such as (4.14) and (4.29), can be formulated, in general terms, as follows:

$$\begin{aligned} Min \quad & G(y) \\ s.t. \quad & f(y)=0 \\ & \underline{H} \le H(y) \le \overline{H} \\ & \underline{y} \le y \le \overline{y} \end{aligned} \tag{4.30}$$

Where

- $y \in R^n$ is a vector of decision variables, including the control and nonfunctional dependent variables.
- G : R^n → R is a scalar function that represents the power system's operation optimization goal.
- f : R^n → R^m is a vector function with conventional power flow equations and other equality constraints.
- H : R^n → R^p is a vector of functional variables, with lower bound $\underline{H}$ and upper bound $\overline{H}$, corresponding to operating limits on the system.

Functions G(y), f(y) and H(y) are assumed to be twice continuously differentiable.

A point $\hat{y}$ is said to feasible if it satisfies all constraints in (4.30). The set of all feasible points defines a feasible region and a feasible point y^* that attains the desired minimum is called a local optimum.

In this thesis, the problem (4.30) is approached by means of technique, namely the primal-dual Interior Point (IP) method, which proved to be a reliable technique for solving OPF problems [15, 16, 17, and 18].

4.5.2 SOLUTION OF NLP VIA INTERIOR POINT METHOD

This section gives a brief outline of the IP method for nonlinear programming. A complete treatise can be found in [20]. The following description is meant only to provide a nomenclature for variables introduced in nonlinear programming techniques and which will be used in this thesis when defining marginal costs. Firstly, all inequalities in problem (4.30) are transformed into equalities by defining a vector of non-negative slack variables s, and adding to the objective function a logarithmic barrier term, which ensures the non negativity condition

$s \geq 0$:

$$\begin{aligned} Min. \quad & G(y) - \mu^k \sum_{i=1}^{p} (\ln(s_{1_i}) + (\ln(s_{2_i})) \\ s.t \quad & f(y) = 0 \\ & -s_1 + \overline{H} - H(y) = 0, \quad s_1 \succ 0 \\ & -s_2 - \underline{H} + H(y) = 0, \quad s_2 \succ 0 \end{aligned} \tag{4.31}$$

Where for sake of simplicity $\underline{y} \leq y \leq \overline{y}$ are included in $\underline{H} \leq H(y) \leq \overline{H}$ and s = (s_1; s_2). The Lagrangian function L associated with (4.31) is as follows:

$$L_\mu(z) = G(y) - \mu^k \sum_{i=1}^{p} (\ln(s_{1_i}) + (\ln(s_{2_i})) - \rho^T f(y) - \mu_1^T(-s_1 + \overline{H} - H(y)) - \mu_2^T(-s_2 - \underline{H} + H(y)) \tag{4.32}$$

Where $\rho(\rho \in R^m)$, $\mu_1(\mu_1 \in R^p)$ and $\mu_2(\mu_2 \in R^p)$ are the Lagrangian multipliers (or dual variables), μ^k $(\mu^k \neq 0)$ is the barrier parameter, and z = (s, μ, y, ρ), being $\mu = (\mu_1, \mu_2)$. The local minimization of (4.32) is satisfied by the KKT optimality condition:

$$\nabla_z L_\mu(z) = 0 \tag{4.33}$$

Then, the IP method works as follows:

Step 0: define an initial point (k = 0), i.e. μ^0 *and* z^0;

Step 1: compute Newton direction, i.e. $[\nabla_z^2 L_\mu(z) \mid k]^{-1} \nabla_z L_\mu(z^k)$, of the current point;

Step 2: compute the step direction ∇_z^k length in the Newton direction and update $z^k \rightarrow z^{k+1}$;

Step 3: if convergence criteria are satisfied, stop; otherwise update $\mu^k --> \mu^{k+1}$ and return to Step 1.

4.6 PRICING ELECTRICITY AND SECURITY

Besides generation and load power scheduling, market clearing mechanism have to provide prices associated with power production and consumption. Two main approaches have been proposed in competitive markets, namely the spot pricing model which gives LMPs and the single-price model based on Market Clearing Price (MCP). The latter is currently widely utilized, since it is "transparent" and "easy" to be computed. However, spot pricing through marginal costs can provide reliable pricing indicators for both generation and congestions [22] and will be utilized in this thesis. Following sections describe marginal cost approach.

4.6.1 Locational Marginal Prices

It is widely recognized that spot pricing through marginal costs can provide reliable pricing indicators [22]. OPF-based market models have the advantage of producing not only the optimal operating point solutions, but also a variety of sensitivity variables through the Lagrangian multipliers, which can be associated with LMPs at each node. LMPs are basically the Lagrangian multipliers of power flow equations associated with real power injections, i.e. $LMP_h = \rho_{ph}$. However, more detailed information can be deduced from the KKT optimality condition applied to the OPF problem. With regard to (4.14), the Lagrangian function is as follows:

$$
\begin{aligned}
Min \quad & L = G - \rho^T f(\delta, V, Q_G, P_S, P_D) \\
& -\mu^T{}_{P_{S\max}} (P_{S\max} - P_S - s_{P_{S\max}}) \\
& -\mu^T{}_{P_{D\max}} (P_{D\max} - P_D - s_{P_{D\max}}) \\
& -\mu^T{}_{P_{D\min}} (P_D - s_{P_{D\min}}) \\
& -\mu^T{}_{I_{hk\max}} (I_{\max} - I_{hk} - s_{I_{hk\max}}) \\
& -\mu^T{}_{I_{kh\max}} (I_{\max} - I_{kh} - s_{I_{kh\max}}) \\
& -\mu^T{}_{Q_{G\max}} (Q_{G\max} - Q_G - s_{Q_{G\max}}) \\
& -\mu^T{}_{Q_{G\min}} (Q_G - Q_{G\min} - s_{Q_{G\max}}) \\
& -\mu^T{}_{V_{\max}} (V_{\max} - V - s_{V_{\max}}) \\
& -\mu^T{}_{V_{\min}} (V - V_{\min} - s_{V_{\min}}) \\
& -\mu^k (\sum_h^{2p} \ln s_h)
\end{aligned}
\tag{4.34}
$$

Then, applying (4.33), one has:

$$
\begin{aligned}
\frac{\partial L}{\partial P_{Si}} &= 0 = C_{Si} - \rho_{PSi} + \mu_{PS\max i} - \mu_{PS\min i} \\
\frac{\partial L}{\partial P_{Di}} &= 0 = -C_{Di} + \rho_{PDi} + \rho_{QDi} \tan(\phi_{Di}) + \mu_{PD\max i} - \mu_{PD\min i}
\end{aligned}
\tag{4.35}
$$

Thus, the LMPs can be defined as

$$
\begin{aligned}
LMP_{Si} &= \rho_{PSi} = C_{Si} + \mu_{PS\max i} - \mu_{PS\min i} \\
LMP_{Di} &= \rho_{PDi} = C_{Di} - \rho_{QDi} \tan(\phi_{Di}) - \mu_{PD\max i} + \mu_{PD\min i}
\end{aligned}
\tag{4.36}
$$

Table 4.1: LMPs and NCPs for six-bus test case

Bus <i>	LMP Rs/MWh	NCP Rs/MWh
1	9.0204	-0.0487
2	8.9805	0.0000
3	9.1455	0.0765
4	9.5630	0.2074
5	9.6535	0.2904
6	9.4284	0.2394

Table 4.1 depicts the LMPs and NCPs of all market participants for the six-bus system example obtained using the standard security constrained OPF (4.14). As it can be noticed, each bus is characterized by a different price, i.e. market participants pay for their consumptions or get paid for their productions according to bids as well

as congestions they cause in the network. Furthermore, comparing LMPs in Table 4.1 allows concluding that system congestions do significantly affect market bids and associated costs, hence the need of a precise model for taking in account security constraints.

4.6.2 Nodal Congestion Prices (NCPs)

Using the decomposition formula for Locational Marginal Prices which has been proposed in [22], [21], one can define a vector of active and reactive Nodal Congestion Prices (NCPs) as follows:

$$NCP = \left(\frac{\partial f^T}{\partial x} \right)^{-1} \frac{\partial H^T}{\partial x} (\mu_{\max} - \mu_{\min}) \tag{4.36}$$

Where x = (θ, V) are voltage phases and magnitudes, H represents the inequality constraint functions (e.g. transmission line powers and currents), and $\mu_{\max}$ and $\mu_{\min}$ are the dual variables or shadow prices associated to inequality constraints. Equation (4.36) for the standard security constrained OPF (4.14) becomes:

$$NCP = [D_x f]^{-1} \left[\frac{\partial I_{hk}}{\partial x} (\mu_{Ihk\max} - \mu_{Ihk\min}) + \frac{\partial P_{hk}}{\partial x} (\mu_{Phk\max} - \mu_{Phk\min}) + \begin{bmatrix} 0 \\ \mu_{V\max} - \mu_{V\min} \end{bmatrix} \right] \tag{4.37}$$

Which for each real power injection h, can be conveniently rewritten as follows?

$$NCP_h = \sum_{k=1}^{I_k} (\mu_{Ihk\max} - \mu_{Ihk\min}) \frac{\partial I_{hk}}{\partial x} + \sum_{k=1}^{I_k} (\mu_{Phk\max} - \mu_{Phk\min}) \frac{\partial P_{hk}}{\partial x} \tag{4.38}$$

Where I_k is the number of lines departing from bus h. Observe that in (4.37) dual variables or shadow prices $\mu_{Phk\max}$ and $\mu_{Phk\min}$ directly affect NCPs, which is the main drawback of transmission congestion limits $P_{hk\max}$ computed off-line, as demonstrated in Chapter 6. For the sake of completeness, Table 4.1 depicts also NCPs for the six-bus system example obtained using the standard security constrained OPF (4.14). Observe that high NCP values correspond to high LMP values, as expected, since LMPs increase when local congestion increases.

CHAPTER-5

VOLTAGE STABILITY CONSTRAINED OPF

5.1 INTRODUCTION

This chapter describes a novel technique for representing system security in the operations of decentralized electricity markets, with special emphasis on voltage stability. The Interior Point is used to solve the Optimal Power Flow problem with a multi-objective function for maximizing both social benefit and the distance to maximum loading conditions. The six bus system with both supply and demand-side bidding is used to illustrate the proposed technique for elastic demand, whereas an IEEE 30-bus test system is used for testing the practical reliability of the proposed method. The results obtained show that the proposed technique is able to improve system security while yielding better market conditions through increased transaction levels and improved Locational marginal prices throughout the system.

5.2 MULTI-OBJECTIVE VSC-OPF

The following optimization problem is proposed to represent an OPF market model, based on what has been proposed in [8, 10, and 11], so that system security is modeled through the use of voltage stability conditions:

$$\text{Min}\, G = -\omega_1 (C_D{}^T P_D - C_S{}^T P_S) - \omega_2 \lambda_c \tag{5.1}$$

$$\text{s.t.} \qquad f(\delta, V, Q_G, P_S, P_D) = 0$$

$$f(\delta_c, V_c, Q_{Gc}, \lambda_c, P_S, P_D) = 0$$

$$\lambda_{c\min} \le \lambda_c \le \lambda_{c\max}$$

$$0 \le P_S \le P_{S\max}$$

$$0 \le P_D \le P_{D\max}$$

$$I_{hk}(\delta, V) \le I_{hk\max}$$

$$I_{kh}(\delta, V) \le I_{kh\max}$$

$$I_{hk}(\delta_c, V_c) \le I_{hk\max}$$

$$I_{kh}(\delta_c, V_c) \le I_{kh\max}$$

$$Q_{G\min} \le Q_G \le Q_{G\max}$$

$$Q_{G\min} \leq Q_{Gc} \leq Q_{G\max}$$

$$V_{\min} \leq V \leq V_{\max}$$

$$V_{\min} \leq V_c \leq V_{\max}$$

A second set of power flow equations and constraints with a subscript c is introduced to represent the system at the limit or "critical" conditions associated with the maximum loading margin λ_c in p.u., where λ is the parameter that drives the system to its maximum loading condition. The maximum or critical loading point could be either associated with a thermal or bus voltage limit or a voltage stability limit (collapse point).

In the multi-objective function G, two terms are present, with their influence on the final solution being determined by the value of the weighting factors ω_1 and ω_2 ($\omega_1 > 0$, $\omega_2 > 0$). The first term represents the social benefit, whereas the second term guarantees that the "distance" between the market solution and the critical point is maximized [24]. Observe that $\omega_1 > 0$, since for $\omega_1 = 0$ there would be no representation of the market in the proposed OPF formulation, rendering it useless. Furthermore, $\omega_2 > 0$, otherwise λ_c will not necessarily correspond to a maximum loading condition of the system. Notice that the two terms of the objective function are expressed in different units, since the social benefit would be typically in Rs/h, whereas the "security" term would be in p.u., which will basically affect the chosen values of ω_1 and ω_2 (typically, $\omega_1 >> \omega_2$). However, it is possible to assume that $\omega_1 = (1 - \omega)$ and $\omega_2 = \omega$ with proper scaled values of ω for each system under study ($0 < \omega < 1$), as this simplifies the optimization problem without losing generality.

Boundaries for the loading margin λ_c have been included in (5.1) based on practical considerations. Thus, the minimum limit $\lambda_{c\min}$ is introduced in order to ensure a minimum level of security in any operating condition and for any value of ω, where the maximum value $\lambda_{c\max}$ imposes a maximum required security level. These conditions ensure that the loading parameter remains within certain limits to avoid solutions of (5.1) characterized by either low security levels ($\lambda_c < \lambda_{c\min}$) or low supply and demand levels ($\lambda_c < \lambda_{c\max}$), which would be unacceptable.

Equations (5.1) and (5.2) are for elastic demand. In the case of a pure inelastic demand, PD is known, and this can be represented in these equations by setting C_{Di} = 0 and $P_{Di} = P_{Dimax}$; hence the problem basically becomes the same as the one analyzed in [10]. In this case, one must be aware that the associated OPF problem may have no solution, as the system may not be able to supply the required demand.

5.2.1 POWER DIRECTIONS

For the current and maximum loading conditions of (5.1), the generator and load powers are defined as follows:

$$P_G = P_{G0} + P_S \quad (5.2)$$

$$P_L = P_{L0} + P_D \quad (5.3)$$

$$P_{Gc} = (1+\lambda_c + k_{Gc})\, P_G \quad (5.4)$$

$$P_{Lc} = (1+\lambda_c)\, P_L \quad (5.5)$$

Where P_{G0} and P_{L0} stand for generator and load powers which are not part of the market bidding (e.g. must-run generators, inelastic loads), and kGc represents a scalar variable used to distribute the system losses associated only with the solution of the critical power flow equations in proportion to the power injections obtained in the solution process, i.e. a standard distributed slack bus model is used. It is assumed that the losses corresponding to the maximum loading level defined by λ_c in (5.1) are distributed among all generators; other possible mechanisms to handle increased losses could be implemented, but they are beyond the main interest of the present thesis.

Observe that the loading parameter multiplies both base case powers and bids, as in $P_{Gl} = (1+\lambda)\,(P_{G0}+P_S)$ and $P_{Ll} = (1+\lambda)(P_{LO}+P_D)$.

The reason for preferring above equations is twofold:

1. Using above equations would mean that load directions depend only on the participants to the auction. If the goal were to determine the impact of the auction on the security and to minimize that impact, this approach could be acceptable; however if the goal is to optimize the auction results to improve the system security, it is more appropriate to determine λ_c considering an increase of load and generation that takes into account also the initial loading and generation pattern.

2. The above Model can lead to numerical issues when power bids PS and PD have low values. To better understand this point, let us consider the case $\omega_2 >> \omega_1$, which

leads to mostly maximize the security (λ_c). In this case, the most secure solution is the closest to the base case condition, thus PS and PD is low; consequently λ_c gets high values. As $\omega_1 \rightarrow 0$, one has PS→ 0, PD→ 0 and, consequently, $\lambda_c \rightarrow \infty$, which is clearly a numerical unstable condition.

5.2.2 MAXIMUM LOADING CONDITION AND AVAILABLE LOADING CAPABILITY

In the proposed OPF-based approach, λ_c represents the maximum loadability of the network and, hence, this value can be viewed as a measure of the congestion of the network. Observe that the maximum loading condition (MLC) and the available loading capability (ALC) can be obtained as a byproduct of the solution of (5.1), as defined in Section 4.4:

$$MLC = (1+\lambda_c)\sum_{j\in J} P_{Lj} \qquad (5.6)$$

$$ALC = \lambda_c \sum_{j\in J} P_{Lj} = \lambda_c TTL \qquad (5.7)$$

For now, contingencies are not considered when computing λ_c, MLC and ALC.

5.2.3 LOCATIONAL MARGINAL PRICES

The Lagrangian multipliers associated with (5.1) correspond to the standard definition of LMPs only when ω=0, i.e. for a pure market model. Lagrangian multipliers for ω>0 would lead to unrealistic results, since they decrease almost linearly with respect to increase in ω. Hence, LMPs which are not dependent of ω are needed.

Consider the following vector objective function:

$$\overline{G} = \begin{bmatrix} -(C_D{}^T P_D - C_S{}^T P_S) \\ -\lambda_c \end{bmatrix} \qquad (5.8)$$

From a fundamental theorem of multi-objective optimization [80], an optimal solution of (5.1) is also a Pareto optimal point for the minimization problem constituted by the objective function (5.8) plus the constraints defined in (5.1). Thus, an optimal solution point of (5.1) has the property of independently minimizing both terms of the objective function (5.8). Based on this premise, for given value of the weighting factor, say ω^*, an IPM is first used to minimize the following Lagrangian function of (5.1):

$$
\begin{aligned}
Min \quad & L = G - \rho^T f(\delta, V, Q_G, P_S, P_D) \\
& -\rho_c^T f(\delta_c, V_c, Q_{Gc}, \lambda_c, P_S, P_D) \\
& -\mu_{\lambda c\max}(\lambda_{c\max} - \lambda_c - s_{\lambda_{c\max}}) \\
& -\mu_{\lambda c\min}(\lambda_c - s_{\lambda_{c\min}}) \\
& -\mu^T{}_{P_{S\max}}(P_{S\max} - P_S - s_{P_{S\max}}) \\
& -\mu^T{}_{P_{D\max}}(P_{D\max} - P_D - s_{P_{D\max}}) \\
& -\mu^T{}_{P_{D\min}}(P_D - s_{P_{D\min}}) \\
& -\mu^T{}_{I_{hk\max}}(I_{\max} - I_{hk} - s_{I_{hk\max}}) \\
& -\mu^T{}_{I_{kh\max}}(I_{\max} - I_{kh} - s_{I_{kh\max}}) \\
& -\mu^T{}_{I_{hkc\max}}(I_{\max} - I_{hkc} - s_{I_{hkc\max}}) \\
& -\mu^T{}_{I_{khc\max}}(I_{\max} - I_{khc} - s_{I_{khc\max}}) \\
& -\mu^T{}_{Q_{G\max}}(Q_{G\max} - Q_G - s_{Q_{G\max}}) \\
& -\mu^T{}_{Q_{G\min}}(Q_G - Q_{G\min} - s_{Q_{G\max}}) \\
& -\mu^T{}_{Q_{Gc\max}}(Q_{G\max} - Q_{Gc} - s_{Q_{Gc\max}}) \\
& -\mu^T{}_{Q_{Gc\min}}(Q_{Gc} - Q_{G\min} - s_{Q_{Gc\max}}) \\
& -\mu^T{}_{V_{\max}}(V_{\max} - V - s_{V_{\max}}) \\
& -\mu^T{}_{V_{\min}}(V - V_{\min} - s_{V_{\min}}) \\
& -\mu^T{}_{V_{c\max}}(V_{\max} - V_c - s_{V_{c\max}}) \\
& -\mu^T{}_{V_{c\min}}(V_c - V_{\min} - s_{V_{c\min}}) - \mu^k(\sum_h^{2p} \ln s_h)
\end{aligned}
\tag{5.9}
$$

Where $\mu^k \in R, \mu_s > 0$, is the barrier parameter, and $\rho\, and\, \rho_c \in R^n$, and all the other $\mu(\mu_h > 0, \forall h)$ correspond to the Lagrangian multipliers. The s variables form the slack vector whose non-negativity condition ($s_h > 0, \forall h$) is ensured by including the logarithmic barrier terms $\sum_h^{2p} \ln s_h$, as described in chapter 4. The solution of (5.9) provides the value of λ_c^* associated with ω^*, along with all other system variables and market bids.

For the following OPF:

$$
Min. \quad \hat{G} = -(C_D{}^T P_D - C_S{}^T P_S) \tag{5.10}
$$

With the same constraints as in (5.1), and loading parameter fixed at $\lambda_c = \lambda_c *$, the solution of (5.1) is also a solution of (5.10), i.e. the vector of voltage phases and magnitudes $(\theta, V, \theta_c andV_c)$, generator reactive powers $(Q_G andQ_{Gc})$, power bids $(P_S andP_D)$, the loss distribution factor (k_{Gc}) and the loading parameter (λ_c) are identical for both (5.1) and (5.10). Observe that the value of λ_c cannot be obtained by the mere solution of (5.10), as its value is basically defined by the value of ω, although it affects the solution and the dual variables of (5.10), it does not explicitly appear in the equations; thus, the Lagrangian multipliers of the power flow equations in (5.10) can be associated with the system LMPs, and can be derived from applying the corresponding KKT optimality conditions as follows:

$$\partial\hat{L}/\partial P_{si} = C_{si} - \rho_{P_{si}} + \mu_{P_{s\max i}} - \mu_{P_{s\min i}} - \rho_{cP_{si}}(1 + \lambda_c^* + k_{Gc}^*) = 0 \qquad (5.11)$$

$$\partial\hat{L}/\partial P_{Di} = -C_{Di} + \rho_{P_{Di}} + \rho_{P_{Qi}} \tan(\phi_{Li}) + \mu_{P_{D\max i}} - \mu_{P_{D\min i}} + \rho_{cP_{Di}}(1 + \lambda_c^*) + \rho_{cQ_{Di}}(1 + \lambda_c^*)\tan(\phi_{Li}) = 0 \qquad (5.12)$$

Where $\hat{L}$ is the Lagrangian of (5.10) and ϕ_{Di} represents a constant load is power factor angle. Thus, the LMPs can be defined as

$$LMPs = \rho_{P_{si}} = C_{si} + \mu_{P_{s\max i}} - \mu_{P_{s\min i}} - \rho_{cP_{si}}(1 + \lambda_c^* + k_{Gc}^*) \qquad (5.13)$$

$$LMP_{Di} = \rho_{P_{Di}} = C_{Di} - \rho_{P_{Qi}} \tan(\phi_{Li}) - \mu_{P_{D\max i}} + \mu_{P_{D\min i}} - \rho_{cP_{Di}}(1 + \lambda_c^*) - \rho_{cQ_{Di}}(1 + \lambda_c^*)\tan(\phi_{Li}) = 0 \qquad (5.14)$$

From this definition, the LMPs are directly related to the costs C_S and C_D, and do not directly depend on the weighting factor ω. These LMPs have additional terms associated with λ_c^* which represent the added value of the proposed OPF technique. If a maximum value $\lambda_{c\max}$ is imposed on the loading parameter, when the weighting factor ω reaches a value, say ω_0, at which $\lambda_c = \lambda_{c\max}$, there is no need to solve other OPFs for $\omega > \omega_0$, since the security level cannot increase any further.

Observe that the computation of these LMPs is quite inexpensive, since the optimal point is already known from the solution of (5.1), thus the determination of the Lagrangian multipliers ρ is basically reduced to solving a set of linear equations.

5.2.4 NODAL CONGESTION PRICES

Using the decomposition formula presented in Section 4.6.2, the real power congestion price at each bus can be rewritten as follows:

$$NCP = [D_x f]^{-1}\left[\frac{\partial I_{hk}}{\partial x}(\mu_{Ihk\,\max} - \mu_{Ihk\,\min}) + \begin{bmatrix} 0 \\ \mu_{V\,\max} - \mu_{V\,\min} \end{bmatrix}\right] \tag{5.15}$$

Observe that NCPs in (5.15) depends only on shadow prices of dual variables $\mu_{Ihk\,\max}$ and $\mu_{Ihk\,\min}$ associated with current thermal limits, since the proposed OPF model 5.1 does not include real power flow limits as in (4.14). However, dependence on voltage security constraints given by the inclusion of the "critical" system f_c and on the loading parameter λ_c are implicit in (5.15).

CHAPTER-6

RESULTS AND DISCUSSIONS

6.1 INTRODUCTION

In the following subsections, the ATC is calculated from 2nd bus to remaining buses using the flow chart given in figure 2.1. The OPF problem (5.1) and the proposed technique for computing LMPs are applied to an IEEE 30-bus system. The results of optimization technique (4.14) are also discussed to observe the effect of the proposed method in the LMPs and system security, which is represented here through the ALC. For both test systems, generator powers were used as the direction needed to obtain a maximum loading point and the associated power flows in the lines, so that proper comparisons can be made.

6.2 IEEE 30-BUS TEST CASE

ATC levels from 2nd bus to remaining buses are calculated using the flow chart (figure 2.1) for RPF method without considering any constraints which are showed in Table 6.1.

Table 6.1: ATC levels from 2nd bus to remaining buses

From 2nd bus to Bus no.	ATC level [MW]	From 2nd bus to Bus no.	ATC level [MW]
3	5.2	4	10.2
5	97.4	6	2.2
7	25.3	8	32.2
9	2.3	10	8.1
11	2.3	12	13.7
13	2.5	14	8.6
15	10.6	16	5.9
17	11.3	18	5.5
19	11.8	20	4.5
21	19.8	22	2.3
23	5.5	24	11.0
25	2.3	26	5.6
27	2.3	28	2.2
29	4.6	30	12.7

6.2.1 CASE 1

Table 6.2 shows the LMPs and NCPs of the IEEE 30-bus test case system without considering any transactions and voltage stability constraints.

Table 6.2: standard OPF solution for IEEE 30-bus test case without any transactions

Bus <i>	V [p.u]	Theta [rad]	P [MW]	Q [MVar]	LMP Rs/MWh	NCP Rs/MWh	Pay [Rs/h]
1	1.1000	0.0000	360.2000	-56.8726	3.3222	0.0000	-1196.657
2	1.0993	-0.1164	96.6010	98.6358	3.5850	0.1189	-346.3126
3	1.0514	-0.1919	-4.7990	-2.3995	3.7559	0.2115	18.0246
4	1.0429	-0.2368	-15.1990	-3.1998	3.8835	0.2665	59.0261
5	1.0624	-0.3216	-113.401	40.2191	4.0150	0.3468	455.3085
6	1.0450	-0.2794	0.0000	0.0000	3.9773	0.3166	-0.0000
7	1.0357	-0.3136	-45.5990	-21.7995	4.0488	0.3548	184.6194
8	1.0659	-0.2985	-28.4788	73.6003	4.0063	0.3319	114.0946
9	1.0376	-0.3923	0.0000	0.0000	3.9900	0.4397	-0.0000
10	1.0061	-0.4542	-11.5990	-3.9997	3.9985	0.5125	46.3782
11	1.1000	-0.3923	0.0001	33.0158	3.9900	0.4397	-0.0004
12	1.0327	-0.4390	-22.3990	-14.9993	3.9123	0.4751	87.6315
13	1.1000	-0.4390	0.0002	52.8533	3.9123	0.4751	-0.0009
14	1.0006	-0.4706	-12.3990	-3.1997	4.0570	0.5357	50.3024
15	0.9907	-0.4722	-16.3990	-4.9997	4.1001	0.5500	67.2374
16	1.0060	-0.4551	-6.9990	-3.5995	4.0063	0.5148	28.0398
17	0.9954	-0.4627	-17.9990	-11.5994	4.0329	0.5294	72.5887
18	0.9701	-0.4927	-6.3990	-1.7997	4.1990	0.5933	26.8696
19	0.9646	-0.4975	-18.9990	-6.7996	4.2206	0.6041	80.1868
20	0.9732	-0.4887	-4.3990	-1.3997	4.1696	0.5844	18.3422
21	0.9792	-0.4710	-34.9990	-22.3994	4.0974	0.5548	143.4050
22	0.9802	-0.4704	0.0000	0.0000	4.0944	0.5535	-0.0000
23	0.9670	-0.4830	-6.3990	-3.1995	4.1871	0.5852	26.7934
24	0.9531	-0.4841	-17.3990	-13.3992	4.2242	0.6003	73.4970
25	0.9560	-0.4684	0.0000	0.0000	4.1615	0.5701	-0.0000
26	0.9174	-0.4854	-6.9990	-4.5993	4.3581	0.6380	30.5025
27	0.9768	-0.4484	0.0000	0.0000	4.0475	0.5206	-0.0000
28	1.0378	-0.2980	0.0000	0.0000	4.0249	0.3428	-0.0000
29	0.9322	-0.4968	-4.7990	-1.7996	4.3359	0.6346	20.8080
30	0.9066	-0.5331	-21.1990	-3.7998	4.5500	0.7192	96.4562

Total Losses = 73.06[MW]

TTL = 578.303 [MW]

IMO Pay = 987.290 [Rs/h]

6.2.2 CASE 2

Table 6.3 gives the LMPs and NCPs for IEEE 30-bus test case system considering the transactions 2-4, 2-8, 2-21 whose magnitudes are decided from ATC algorithm and without considering voltage stability constraints.

Table 6.3: standard OPF solution for IEEE 30-bus test case with transactions

Bus <i>	V [p.u]	Theta [rad]	P [MW]	Q [MVar]	LMP Rs/MWh	NCP Rs/MWh	Pay [Rs/h]
1	1.1000	0.0000	360.2000	-56.3518	3.3283	0.0000	-1198.867
2	1.0992	-0.1161	96.6010	98.4094	3.5908	0.1692	-346.8727
3	1.0508	-0.1928	-4.7990	-2.3995	3.7653	0.3034	18.0695
4	1.0422	-0.2380	-20.3990	-3.1998	3.8940	0.3823	79.4327
5	1.0629	-0.3187	-110.781	39.7543	4.0155	0.4899	444.8446
6	1.0448	-0.2789	-0.0000	0.0000	3.9843	0.4510	0.0000
7	1.0358	-0.3121	-45.5990	-21.7995	4.0534	0.5037	184.8327
8	1.0666	-0.2960	-22.1147	74.2406	4.0085	0.4695	88.6459
9	1.0367	-0.3949	0.0000	0.0000	4.0002	0.6320	-0.0000
10	1.0046	-0.4594	-11.5990	-3.9997	4.0108	0.7405	46.5208
11	1.1000	-0.3934	0.7751	33.5000	4.0002	0.6300	-3.1004
12	1.0322	-0.4425	-22.3990	-14.9993	3.9205	0.6830	87.8147
13	1.1000	-0.4425	0.0000	53.2852	3.9205	0.6830	-0.0001
14	0.9999	-0.4744	-12.3990	-3.1997	4.0660	0.7703	50.4144
15	0.9898	-0.4761	-16.3990	-4.9997	4.1105	0.7915	67.4085
16	1.0049	-0.4593	-6.9990	-3.5995	4.0170	0.7417	28.1149
17	0.9941	-0.4676	-17.9990	-11.5994	4.0448	0.7641	72.8019
18	0.9690	-0.4971	-6.3990	-1.7997	4.2110	0.8547	26.9462
19	0.9634	-0.5022	-18.9990	-6.7996	4.2333	0.8708	80.4286
20	0.9720	-0.4935	-4.3990	-1.3997	4.1823	0.8429	18.3981
21	0.9767	-0.4783	-39.5990	-22.3994	4.1199	0.8069	163.1421
22	0.9778	-0.4773	0.0000	0.0000	4.1150	0.8038	-0.0000
23	0.9657	-0.4875	-6.3990	-3.1995	4.1998	0.8434	26.8742
24	0.9515	-0.4893	-17.3990	-13.3992	4.2395	0.8672	73.7622
25	0.9552	-0.4713	0.0000	0.0000	4.1691	0.8189	-0.0000
26	0.9166	-0.4883	-6.9990	-4.5993	4.3666	0.9164	30.5618
27	0.9765	-0.4500	0.0000	0.0000	4.0507	0.7450	-0.0000
28	1.0376	-0.2972	-0.0000	0.0000	4.0311	0.4880	0.0000
29	0.9319	-0.4985	-4.7990	-1.7996	4.3398	0.9082	20.8265
30	0.9062	-0.5347	-21.1990	-3.7998	4.5544	1.0293	96.5485

Total Losses = 39.898[MW]

TTL = 580.979 [MW]

IMO Pay = 157.547 [Rs/h]

6.2.3 CASE 3

Table 6.4 gives the LMPS and NCPs for IEEE 30-bus test case including voltage stability constraint and considering no transactions.

Table 6.4: VSC-OPF solution for IEEE 30-bus test case without any transactions

Bus <i>	V [p.u]	Theta [rad]	P [MW]	Q [MVar]	LMP Rs/MWh	NCP Rs/MWh	Pay [Rs/h]
1	1.1000	0.0000	238.9855	-26.4653	2.1835	0.0000	-521.8167
2	1.0874	-0.0779	37.7165	25.5913	2.2968	0.0461	-86.6290
3	1.0721	-0.1179	-2.3990	-1.1995	2.3444	0.0715	5.6243
4	1.0654	-0.1451	-7.5990	-1.5998	2.3909	0.0890	18.1683
5	1.0557	-0.2192	-94.199	13.7624	2.4816	0.1327	233.7680
6	1.0617	-0.1726	0.0000	0.0000	2.4273	0.1066	-0.0000
7	1.0520	-0.2001	-22.799	-10.8995	2.4634	0.1238	56.1631
8	1.0624	-0.1847	-29.999	9.6246	2.4427	0.1137	73.2774
9	1.0728	-0.2249	0.0000	0.0000	2.4271	0.1369	-0.0000
10	1.0655	-0.2525	-5.7990	-1.9997	2.4269	0.1533	14.0734
11	1.1000	-0.2249	-0.0000	14.3798	2.4271	0.1369	0.0000
12	1.0711	-0.2407	-11.199	-7.4993	2.3963	0.1417	26.8363
13	1.1000	-0.2407	0.0000	22.7150	2.3963	0.1417	-0.0000
14	1.0572	-0.2556	-6.1990	-1.5997	2.4351	0.1543	15.0955
15	1.0535	-0.2571	-8.1990	-2.4997	2.4468	0.1574	20.0612
16	1.0613	-0.2503	-3.4990	-1.7995	2.4251	0.1517	8.4853
17	1.0592	-0.2554	-8.9990	-5.7994	2.4343	0.1560	21.9065
18	1.0458	-0.2672	-3.1990	-0.8997	2.4728	0.1664	7.9103
19	1.0443	-0.2700	-9.4990	-3.3996	2.4789	0.1690	23.5475
20	1.0488	-0.2666	-2.1990	-0.6997	2.4673	0.1658	5.4257
21	1.0531	-0.2599	-17.499	-11.1994	2.4512	0.1612	42.8931
22	1.0535	-0.2597	0.0000	-0.0000	2.4503	0.1610	-0.0000
23	1.0446	-0.2633	-3.1990	-1.5995	2.4691	0.1647	7.8987
24	1.0411	-0.2657	-8.6990	-6.6992	2.4794	0.1687	21.5683
25	1.0370	-0.2576	0.0000	0.0000	2.4650	0.1618	-0.0000
26	1.0197	-0.2647	-3.4990	-2.2993	2.5086	0.1725	8.7777
27	1.0428	-0.2483	0.0000	0.0000	2.4385	0.1524	-0.0000
28	1.0588	-0.1826	-0.0000	-0.0000	2.4413	0.1135	0.0000
29	1.0234	-0.2689	-2.3990	-0.8996	2.5037	0.1712	6.0063
30	1.0122	-0.2837	-10.599	-1.8998	2.5487	0.1843	27.0139

lambda_c = 0.1 [p.u.]

Kg = 0.016125 [p.u.]

Total Losses = 58.96[MW]

Total Transaction Level = 563.477 [MW]

Maximum Loading Condition = 619.825 [MW]

Available Loading Capability = 56.3478 [MW]

IMO Pay = 164.117 [Rs/h]

6.2.4 CASE 4

Table 6.5 gives the LMPS and NCPs for IEEE 30-bus test case considering transactions 2-4, 2-8, 2-21 whose magnitudes are decided from ATC algorithm and voltage stability constraint.

Table 6.5: VSC-OPF solution for IEEE 30-bus test case with transactions

Bus <i>	V [p.u]	Theta [rad]	P [MW]	Q [MVar]	LMP Rs/MWh	NCP Rs/MWh	Pay [Rs/h]
1	1.1000	0.0000	245.2375	-27.1689	2.1883	0.0000	-536.6460
2	1.0874	-0.0798	39.2872	27.3989	2.3047	0.0485	-90.5452
3	1.0712	-0.1217	-2.3990	-1.1995	2.3552	0.0759	5.6502
4	1.0643	-0.1498	-10.1990	-1.5998	2.4035	0.0945	24.5131
5	1.0556	-0.2228	-94.1990	14.0943	2.4924	0.1388	234.7794
6	1.0607	-0.1777	0.0000	0.0000	2.4408	0.1129	-0.0000
7	1.0513	-0.2047	-22.7990	-10.8995	2.4760	0.1303	56.4505
8	1.0614	-0.1906	-32.1990	10.2919	2.4573	0.1207	79.1228
9	1.0720	-0.2318	0.0000	0.0000	2.4413	0.1452	-0.0000
10	1.0644	-0.2603	-5.7990	-1.9997	2.4414	0.1627	14.1579
11	1.1000	-0.2318	-0.0000	14.8043	2.4413	0.1452	0.0000
12	1.0706	-0.2471	-11.1990	-7.4993	2.4084	0.1497	26.9718
13	1.1000	-0.2471	0.0000	23.0808	2.4084	0.1497	-0.0000
14	1.0567	-0.2622	-6.1990	-1.5997	2.4477	0.1628	15.1731
15	1.0529	-0.2639	-8.1990	-2.4997	2.4599	0.1662	20.1691
16	1.0605	-0.2573	-3.4990	-1.7995	2.4386	0.1604	8.5326
17	1.0583	-0.2629	-8.9990	-5.7994	2.4485	0.1652	22.0344
18	1.0450	-0.2744	-3.1990	-0.8997	2.4867	0.1758	7.9549
19	1.0434	-0.2773	-9.4990	-3.3996	2.4933	0.1786	23.6836
20	1.0479	-0.2740	-2.1990	-0.6997	2.4818	0.1754	5.4574
21	1.0515	-0.2686	-19.7990	-11.1994	2.4682	0.1716	48.8685
22	1.0521	-0.2682	0.0000	-0.0000	2.4669	0.1711	-0.0000
23	1.0438	-0.2705	-3.1990	-1.5995	2.4832	0.1741	7.9437
24	1.0399	-0.2735	-8.6990	-6.6992	2.4946	0.1785	21.7003
25	1.0360	-0.2645	0.0000	0.0000	2.4788	0.1709	-0.0000
26	1.0187	-0.2716	-3.4990	-2.2993	2.5228	0.1820	8.8273
27	1.0420	-0.2546	0.0000	0.0000	2.4514	0.1607	-0.0000
28	1.0578	-0.1880	-0.0000	-0.0000	2.4551	0.1203	0.0000
29	1.0225	-0.2753	-2.3990	-0.8996	2.5171	0.1803	6.0385
30	1.0113	-0.2901	-10.5990	-1.8998	2.5625	0.1938	27.1597

lambda_c = 0.8 [p.u.]

kg = 0.13168 [p.u.]

Total Losses = 15.745[MW]

Total Transaction Level = 290.479 [MW]

Maximum Loading Condition = 522.862 [MW]

Available Loading Capability = 232.383 [MW]

IMO Pay = 37.9976 [Rs/h]

Results for the OPF formulation (4.14) are reported in Table 6.2. Table 6.4, on the other hand, shows the solution obtained for the proposed multi-objective OPF (5.1) for $\omega = 10^{-3}$, which is referred to here as Voltage Stability Constrained-OPF (VSC-OPF), with mostly the social benefit being considered in the objective function. For both solutions, generator voltages are at their maximum limits. However, in comparison with the standard OPF approach, the solution of the proposed method provides better LMPs, a higher total transaction level ($\sum_i P_{Li}$) and higher ALC. The improved LMPs result also in a lower total price paid to the Independent Market Operator (Pay_{IMO}) which is computed as the difference between demand and supply payments, as follows:

$$Pay_{IMO} = \sum_{i \in I} C_{Si} P_{Gi} - \sum_{j \in J} C_{Dj} P_{Lj} \tag{6.1}$$

And the network congestion prices are lower, even though the system losses are higher.

LMPs and NCPs generally decrease in this example as the security levels increase, since the auction solutions move away from the security limits, i.e. the system is less congested. Furthermore, even though the LMPs and the overall total transaction level decrease, local bids may increase or decrease, accordingly to the power schedule. Observe that the proposed methodology is designed to give operators and market participants a series of solutions to allow them to analyze the effect of system security on power bids and vice versa, so that proper operating and bidding decisions can be made.

CHAPTER-7
CONCLUSIONS

This thesis presented the calculation of ATC level and study of OPF- based electricity markets with inclusion of voltage stability constraints and discussed how these constraints affect Locational marginal prices and nodal congestion prices.

The proposed multi-objective Voltage Stability Constrained optimal power flow based model provides a set of solutions which range from a quasi maximization of the social benefit to a quasi maximization of the system loading margin. Thus practitioners can choose the best compromise between total transaction level and stability margin. Nodal congestion prices shown by the proposed techniques are generally lower than the ones obtained by means of standard security constrained OPF computations, thus demonstrating that the inclusion of accurate security constraints help in getting better market solutions and fair prices.

As a consequence of including the proposed voltage stability constraints, the solution of OPF-based electricity markets provides the available loading capability (ALC), which is a simple and direct index of the stability margin of the system current solution. Using an "all in one" optimization techniques, also avoids off-line stability computations, which are generally needed to validate security of standard simple auction based market clearing mechanisms.

The presented test examples demonstrate that the proposed technique can be reasonably applied in practice, and can be used in on-line applications for single market auction and/or provide to system operators and market participants a tool to handle together electricity prices and stability issues.

Finally, the proposed VSC-OPF model appears to be much more complicated than the techniques commonly in use by practitioners and market participants to determine electricity costs. This could in turn be considered a drawback, since the computation of electricity prices has to be as transparent and as simple as possible. A solution could be splitting the market clearing mechanism and the stability computations into two different yet linked processes, repeated iteratively until a satisfactory solution is found.

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APPENDIX A

DATA FOR SAMPLE SIX- BUS SYSTEM (AT 100MVA BASE)

Table A.1 Generator power data

Bus No.	Real power generation		Reactive power limits		Specified Voltage(p.u.)
	Min(MW)	Max(MW)	Min(MVAR)	Max(MVAR)	
1	0	90	-150	150	1.10
2	0	140	-150	150	1.10
3	0	60	-150	150	1.10

Table A.2 Load bus data

Bus No.	Load	
	Real(MW)	Reactive(MVAR)
4	90	60
5	100	70
6	90	60

Table A.3 supplier cost curve characteristics

Gen No.	a	b	c
1	0	9.7	0
2	0	8.8	0
3	0	7.0	0

Table A.4 Line data

Line No.	From bus	To bus	Resistance(p.u)	Reactance(p.u)	1/2*B
1	1	2	0.1	0.2	0.02
2	1	4	0.05	0.2	0.02
3	1	5	0.08	0.3	0.03
4	2	3	0.05	0.25	0.03
5	2	4	0.05	0.1	0.01
6	2	5	0.1	0.3	0.02
7	2	6	0.07	0.2	0.025
8	3	5	0.12	0.26	0.025
9	3	6	0.02	0.1	0.01
10	4	5	0.2	0.4	0.04
11	5	6	0.1	0.3	0.03

DATA FOR IEEE-30 BUS SYSTEM (AT 100MVA BASE)

The IEEE-30 bus system in shown in fig A.1. The system data is taken from the [25]. The relevant data are provided in the following tables.

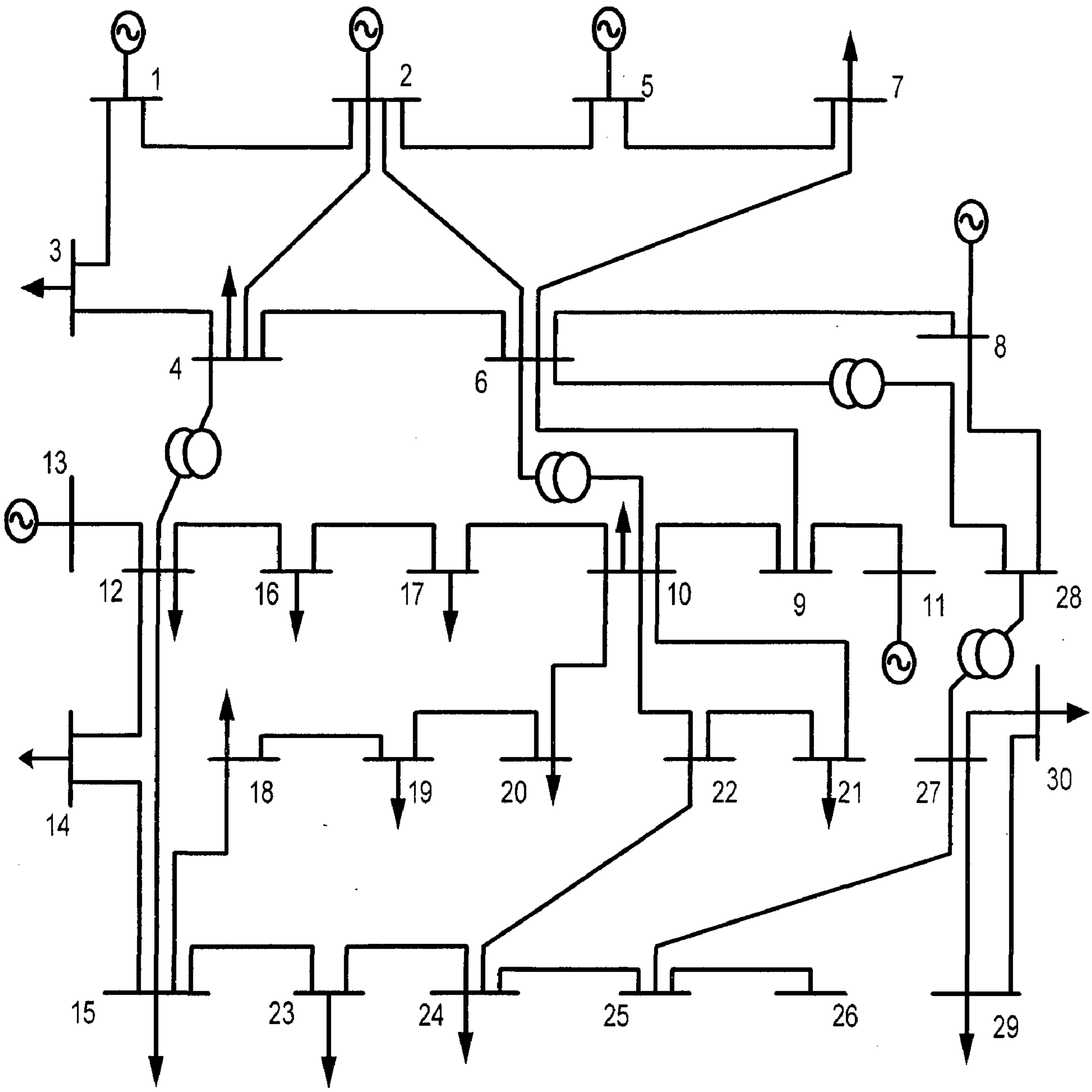

Fig. A.1. IEEE30 bus system.

Table A.5 Generator power data

Bus No.	Real power generation		Reactive power limits		Specified Voltage(p.u.)
	Min(MW)	Max(MW)	Min(MVAR)	Max(MVAR)	
1	50	200	-20	250	1.06
2	20	80	-20	100	1.043
5	15	50	-15	80	1.01
8	10	80	-15	60	1.01
11	10	50	-10	50	1.082
13	12	80	-15	60	1.071

Table A.6 Load bus data

Bus No.	Load	
	Real(MW)	Reactive(MVAR)
2	21.7	12.7
3	2.4	1.2
4	7.6	1.6
5	94.2	19
7	22.8	10.9
8	30	30
9	0	0
10	5.8	2
12	11.2	7.5
14	6.2	1.6
15	8.2	2.5
16	3.5	1.8
17	9	5.8
18	3.2	0.9
19	9.5	3.4
20	2.2	0.7
21	17.5	11.2
22	0	0
23	3.2	1.6
24	8.7	6.7
25	0	0
26	3.5	2.3
27	0	0
28	0	0
29	2.4	0.9
30	10.6	1.9

Table A.7 Transformer data

Line No	From Bus	To bus	Series Impedance (p.u)		Taps
			Resistance	Reactance	
11	6	9	0	0.208	0.978
12	6	10	0	0.556	0.969
15	4	12	0	0.256	0.932
36	28	27	0	0.396	0.968

Table A.8 supplier cost curve characteristics

Gen No.	a	b	c
1	0.012	12	150
2	0.0096	9.6	96
3	0.013	13	105
4	0.0094	9.4	94
5	0.001	10	100
6	0.002	9.8	95

Table A.9 Line data

Line No.	From bus	To bus	Resistance(p.u)	Reactance(p.u)	1/2*B	Line limit(MVA)
1	1	2	0.0192	0.0575	0.0264	50
2	1	3	0.0452	0.1852	0.0204	50
3	2	4	0.057	0.1737	0.0184	50
4	3	4	0.0132	0.0379	0.0042	50
5	2	5	0.0472	0.1983	0.0209	50
6	2	6	0.0581	0.1763	0.0187	50
7	6	4	0.0119	0.0414	0.0045	50
8	5	7	0.046	0.116	0.0102	50
9	6	7	0.0267	0.082	0.0085	50
10	6	8	0.012	0.042	0.0045	50
11	6	9	0	0.208	0	50
12	6	10	0	0.556	0	50
13	9	11	0	0.208	0	80
14	9	10	0	0.11	0	50
15	4	12	0	0.256	0	50
16	12	13	0	0.14	0	60
17	12	14	0.1231	0.2559	0	50
18	12	15	0.0662	0.1304	0	50
19	12	16	0.0945	0.1987	0	50
20	14	15	0.221	0.1997	0	50
21	16	17	0.0824	0.1923	0	50
22	15	18	0.1073	0.2185	0	50
23	18	19	0.0639	0.1292	0	50
24	19	20	0.034	0.068	0	50
25	10	20	0.0936	0.209	0	50
26	10	17	0.0324	0.0845	0	50
27	10	21	0.0348	0.0749	0	50
28	10	22	0.0727	0.1499	0	50
29	21	22	0.0116	0.0236	0	50
30	15	23	0.1	0.202	0	50
31	22	24	0.115	0.179	0	50
32	23	24	0.132	0.27	0	50
33	24	25	0.1885	0.3292	0	50
34	25	26	0.2544	0.38	0	50
35	25	27	0.1093	0.2087	0	50
36	28	27	0	0.396	0	50
37	27	29	0.2198	0.4153	0	50
38	27	30	0.3202	0.6027	0	50
39	29	30	0.2399	0.4533	0	50
40	8	28	0.0636	0.2	0.0214	50
41	6	28	0.0169	0.0599	0.065	50