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Optimal DG Placement: A Multimethod Analysis

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Abstract

With Power System being restructured in the vision of Smart Grid, it is important now more than ever to find suitable locations to place Distributed Generators (DG). Distributed generators, which may be renewable, are not limited to specific locations as in the case of conventional generators. Several papers have been published that make suggestions on where the optimal location of DG should be in a system. Objectives ranging from loss minimization to total cost minimization have been the factor for such studies. In this study, a new method is introduced that hopes to improve a current system in three ways by maximizing load, minimizing the locational marginal price and improving line contingency scenarios. The proposed methodology is simulated using MATPOWER's Optimal Power Flow on the IEEE 14 bus test system.

Key Words: Distributed Generation, Optimal Power Flow, MATPOWER, Locational Marginal Price, IEEE 14 bus

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Chapter 1

Introduction

1.1 Overview

1.1.1 Power System Topology: Then and Now

The hierarchy of the traditional power system has been consisting of generation, transmission, distribution and the consumers. Generation sites were on the top of the hierarchy and power only flowed from this top level all the way to the consumers. As cities began to grow and distributed over a large area, so did the generation of power. If a single plant was not enough, more powerful plants were created on the outskirts of the cities. Generation sites acted as the head of the electric power system.

Over time the idea of a centralized generation site is rapidly becoming obsolete. Power plants are expensive to build even if one manages to find a land big enough to build it. If we overlook the costs and availability of building a new generation plant, a system as non-linear as power system is susceptible to so many other drawbacks. Since a lot of stations are located a good distance away from load centers, costs of transmission can be quite high. Longer lines mean higher line resistances which cause more I^2R losses.

A method of preventing I^2R losses is to generate extremely high voltages but doing so results in higher corona discharge losses. Corona discharge losses not only waste power but are also strong enough to cause insulation damage and ultimately equipment damage. They are also responsible for creating gases such as ozone and nitrogen oxide quite harmful to humans.

To prevent losing more land and space to power plants and lengthy transmission lines, the world has embraced the idea of smart grid. A smart grid, consisting of distributed generation sites, smart meters and transparent information, aims to provide better reliability and security than the present power system design. The flow of electricity becomes multidirectional, a system able to route power where necessary. Distributed generation sites which may use renewable energy sources can be assigned close to the load centers. Having generation sites closer to the consumers help mitigate the above mentioned problems as well as provide better security to the grid. Power can be redirected at will preventing load shedding.

A big innovation in smart grid is the use of renewable sources instead of traditional generators. The detrimental effects of global warming have repurposed many to seek energy solutions with renewable sources. Another positive result from this endeavor is the inclusion of generation from consumers. Consumers with distributed generation sources whether it be solar or diesel based will be connected to the grid. They will be able to sell their extra generation to the grid. In addition, the federal and state provide incentives to promote more customers from creating local distributed generation sources. These extra incentive will encourage a lot of consumers to become prosumers, a term coined by the creators of Transactive energy. These prosumers not only produce energy for themselves but also provide generation back to the grid when it may be required.

1.1.2 Optimal Power Flow

Power flow analysis gives information about bus voltage magnitudes and angles, and real and reactive powers at every bus but does not consider generator costs. Economic dispatch considers generator costs and generator operating limits but does not take into account contingency constraints and transmission constraints such as line thermal limits. Economic dispatch also does not include voltage angle constraints and bus voltage magnitude constraints to ensure the system is stable. Thus researchers developed Optimal Power Flow to incorporate all the drawbacks from load flow and economic dispatch. Optimal Power Flow is an optimization method and has become a revolutionary tool in Power System Engineering.

Optimal Power Flow (OPF) was formulated first in 1962 by J. Carpentier. OPF problem is to find a steady state operating point that minimizes the cost of electric power generation subject to operating constraints. However, it has proven to be not as straightforward. The problem is very computationally stressful for its complex constraints and takes a long time to reach a solution. An engineer might need to run OPF every five minutes to ensure the system can provide for the load forecast to avoid system collapse.

Another result of OPF is locational marginal prices (LMP). LMP is the lowest possible bid at a particular bus for supplying one extra MW of electricity. LMP varies from bus to bus and depends on network topology, demand, availability of generators, and line congestions. To give a clear explanation of Locational Marginal Price, the following 3 bus system has been adapted from [29]. There are 3 generators at each bus. These are G1, G2, and G3 and each able to supply 400 MW. Bus 3 serves as the load bus. The generators have different marginal prices G1 at \$15/MWh, G2 at \$18/MWh and G3 at \$25/MWh. All three lines have equal impedances. If there is no line limit to the three bus system and the total load of the system falls under 400 MW, the entirety of the load will be fulfilled by G1. The cheapest generator has precedence over all others. Figure 1.1 below explains the case for a 360 MW load. Since power flow distributes inversely to the impedance of the line and as all lines are considered to have the same impedances, it is safe to assume that 2/3 of the generations from G1 (240 MW) will always flow to bus 3 through the shorter path, avoiding the higher impedance path. For the next MW, thererfore, incremental load drawn from any of the buses can be satisfied by G1, the LMP at each bus is $15/MWh.

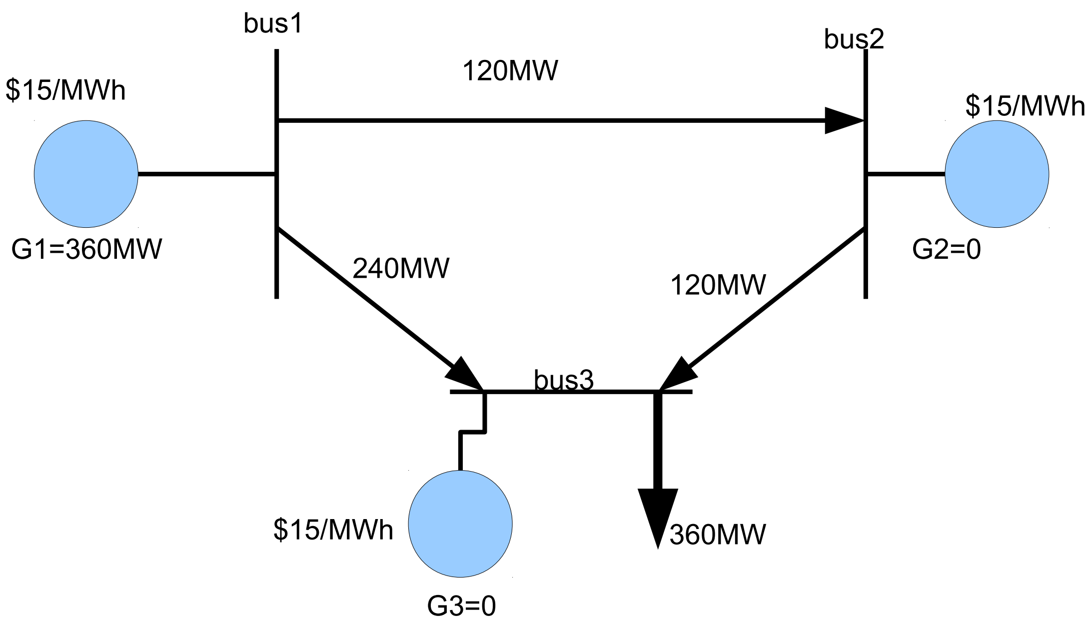


Figure 1.1: Three bus system under an unconstained condition

Now if we introduce the transmission constraint of 200MW for each of the three lines, we get the following scenario.

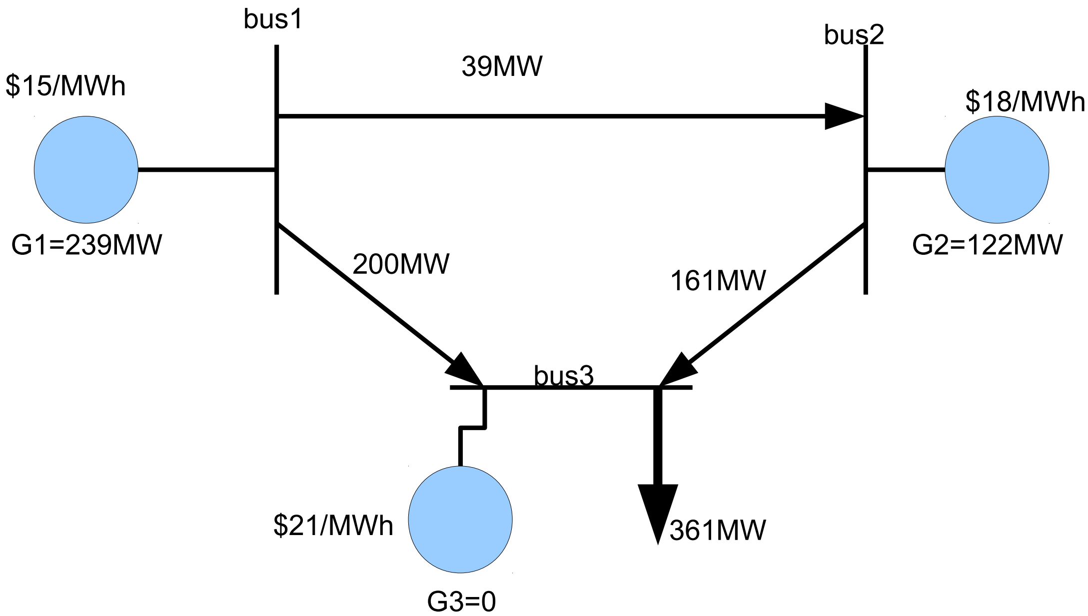


Figure 1.2: Three bus system under a constained condition

Due to the congested line between Bus1 and Bus3, G2 has to be dispatched as shown in Figure 1.2. LMP at bus 2 and bus 3 has changed to reflect the situation of the new network. At bus 2 the marginal cost \$18/MWh of G2 is considered as the incremental cost at that location. For bus 3, it is not as straight forward. Both G1 and G2 are redispatched to supply the next incremental MW for bus 3, thus giving us the equation below.

$$P_{G1} + P_{G2} = 1MW \tag{1.1}$$

Again we consider power flow being affected by the line impedance. The maximum power will flow through the shortest path since the line impedances here are the same. And as the line between bus 1 and bus 3 is fully loaded, the power flow in the line has to be zero, as shown in the equation below.

$$\frac{2}{3}P_{G1} + \frac{1}{3}P_{G2} = 0MW \tag{1.2}$$

Solving for Equation 1.1 and 1.2 yields PG1 to be -1 MW and PG2 to be 2 MW. This suggests that G1 should reduce generation by 1 MW and G2 should increase by 2 MW. The LMP for bus 3 can be calculated with these results and it is, LMP_3 = (-1) (15) +(2) (18) = $ 21/MWh.

The LMP is not equal to the marginal cost of G3, which is $25/MWh, since G3 has not been dispatched yet. Once the two lines connected to bus 3 become congested, there will be no choice but to dispatch the higher priced G3. LMP based on OPF captures the actual price of a particular location. The objective of OPF is to minimize the cost of fuel consumption. LMP is the added bonus required to find the minimum cost for 1 MW extra generation at a particular location. LMP can be a valuable tool while pursuing deregulation or for making future planning for a system.

1.2 Literature Review

1.2.1 Optimal DG placement

Social Welfare Maximization using OPF

Durga Gautam and Nadarajah Mithulananthan [20] presented two methodologies for selecting an optimal location for placement of DG. The analysis includes the use of optimal power flow to determine locational marginal price at each bus of the IEEE 14-bus system. The placement as well as sizing are determined by two criteria, one being the maximization of social welfare and the other being the maximization of profit. Seven (7) unique distributed generators were used for the study, to encompass how different priced DGs affect the LMP of a single system.

The social welfare objective function is formulated as the quadratic benefit curve submitted by the buyer (DISCO) subtracted by the quadratic bid curve submitted by the seller (GENCO) minus the quadratic cost curve supplied by the DG owner, giving the following,

$$\max \sum_{i=1}^{N} B_i(P_{Di}) - C_i(P_{Gi}) - C_i(P_{DGi}) \tag{1.3}$$

Since all optimization problems require the minimization of the objective function, equation 1.3 can be rewritten as:

$$\min \sum_{i=1}^{N} C_i(P_{Di}) - B_i(P_{Gi}) + C_i(P_{DGi}) \tag{1.4}$$

The second method called profit maximization method uses profit as objective function,

$$Profit_i = \lambda_i \times P_{DGi} - C(P_{DGi}) \tag{1.5}$$

where lambda is LMP at a DG location i, and C is actual cost of producing energy at that location.

Using the objective functions identified, optimal power flow is used to minimize the overall cost to the system while taking into account many constraints presented in the test system. The result of OPF is locational marginal prices which vary due to marginal loss component and marginal congestion component.

The authors use two ranking systems to select the ideal place for the DG. One is LMP based ranking (from highest to lowest), where the bus with highest LMP is the location for DG placement. The idea is that the higher LMP implies higher generation constricted by demand at that bus. Adding a DG there will mitigate the demand from the existing generator and thus drive down the prices, thus increasing social welfare.

$$LMP = \begin{bmatrix} LMP_1 \\ LMP_2 \\ LMP_3 \\ \cdots \\ \cdots \\ LMP_n \end{bmatrix} \tag{1.6}$$

The other method, consumer payment (CP) based ranking, ranks the total amount that the consumer pays to use electricity at a single bus, from highest to lowest.

$$CP = LMP_i \times Load_i = \begin{bmatrix} CP_1 \\ CP_2 \\ CP_3 \\ \cdots \\ \cdots \\ CP_n \end{bmatrix} \tag{1.7}$$

The consumer payment ranking addresses two issues, one where the demand is high but the LMP is low and another where the LMP is high but the demand is low. Preference will be given to the bus location where the CP not the LMP is the highest, satisfying the dominant load of the system. This ultimately means the customer at that location would be paying less compared to the system with no DG.

The process of selecting the candidate buses is iterative and is repeated with all seven DGs to observe the effect of fuel costs of different generators. The cost functions of DGs are assumptions made to include the wide variety of DGs that are available in the market today.

The results are obtained for both social welfare maximization and profit maximization

DG ID	aDG	bDG	cDG
DG1	0.002	15	0
DG2	0.004	19	0
DG3	0.04303	20	0
DG4	0.25	20	0
DG5	0.1	30	0
DG6	0.01	40	0
DG7	0.003	43	0

Table 1.1: Distribution generation data

and the results summarized below.

DG	Best location	Optimal DG size (MW)	Social Welfare ($/h)	Remarks
DG1	Bus 4	202.62	8460.47	CP based ranking
DG2	Bus 4	195.05	7586.12	CP based ranking
DG3	Bus 9	141.28	6427.09	-
DG4	Bus 14	41.94	4993.77	LMP based ranking
DG5	Bus 14	50.38	4848.79	LMP based ranking
DG6	Bus 14	42.84	4577.18	LMP based ranking
DG7	Bus 14	25.33	4483.04	LMP based ranking

Table 1.2: Social Welfare result summary for the placement of DG with different cost characteristics

When the social welfare is used as the objective function, DG1, DG2 gave the highest social welfare when placed at Bus 4 which was determined by CP based ranking. DGs 4 to 7 maximized social welfare when placed at Bus 14 by following the LMP based ranking system. The optimal location for DG3 that maximizes the social welfare is Bus 9, which does not agree with either ranking methods. It was concluded that the lower incremental cost of the DG favors the CP based ranking as well as the increase of DG penetration. The results are summarized in Table 1.2.

With the results from profit maximization, Table 1.3, we find again that for lower priced DG1 and DG2 the placement is chosen using CP based ranking to generate the most profit, while the placement for higher priced DG6 and 7 is chosen using LMP based ranking. Place-

DG	Best location	Optimal DG size (MW)	Profit ($/h)	Remarks
DG1	Bus 4	119.43	2766.58	CP based ranking
DG2	Bus 4	119.43	2260.33	CP based ranking
DG3	Bus 9	105.38	1592.49	-
DG4	Bus 11	37.29	470.72	-
DG5	Bus 4	50.46	323.53	-
DG6	Bus 14	21.76	75.14	LMP based ranking
DG7	Bus 14	12.55	29.25	LMP based ranking

Table 1.3: Profit result summary for the placement of DG with different cost characteristics

ment of DGs 3 to 5 for miximized profit does not follow any of the ranking methods.

DGs with lower incremental costs compared to central generating stations have a higher penetration and their placement are found to follow the ranking made on the basis of consumer payment. On the other hand, DGs with higher incremental costs have lower penetration and their placement is found to follow the ranking made on the basis of LMP. It has also been observed that a high penetration of DG can also lead to negative profit for the DG owner. The situation is found to prevail when LMP decreases considerably due to high DG penetration. If LMP decreases to a value making the consumer payment lower than the operating cost of DG, profit for DG owner would be negative. Under such scenario, DG owner will find no incentive for placement. (DURGA)

Optimal DG placement methods

The problem of optimal placement of distributed generation has been studied extensively in the following papers [3–5, 9, 12, 23, 25, 31, 34, 35]. Distributed generation has been a hot topic for quite a while. Researchers have put forward several methods to properly utilize the small generation stations in terms of placement and availability if considering renewable energy systems. The various types of distributed generation present the problem of dispatchability as renewable energy generation is entirely controlled by the availability of renewable energy source such as solar and wind. The desired outcome from DG placement includes but is not limited to minimization of total power losses, stability of voltage and reduction of total production costs.

[3] uses a modified Genetic Algorithm (GA) that utilizes a fuzzy controller to ensure the optimum sizing and location of DG placement in the system. The method also aims to maximize the system loading margin and the profit of the DISCO. The 6 bus and the 30 bus systems are used to test their method and compared to existing GA approach to DG location optimization. Also demonstrated in this paper is the economic viability relative to upgrading substation and feeders to possible increase of future loads.

[4] provides a methodology to optimally allocate various renewable distribution generation units to reduce the overall annual energy loss in the system. The proposal consists of creating a probabilistic generation-load model which takes account of all the possible operating conditions of the renewable DG units with their probabilities. The entire system is looked at as a mixed integer nonlinear programming (MINLP) problem, with an objective function of minimizing the system's annual energy losses. The authors showed that there is significant reduction in the annual energy loss for all the scenarios proposed while keeping the system constraints from violating limits.

[5] takes a look at the DG placement problem using the genetic algorithm approach to ensure the solution that satisfies all inputs to the system, mainly the variation of load in

the system. Optimal location and quantum of DG are found in this paper to minimize the cumulative cost of power purchased by the optimally reconfigured system.

[31] presents a novel hybrid Genetic Algorithm (GA)/ Particle Swarm Optimization (PSO) approach for optimal location and sizing of DG. It was found that the locations and capacities of DG sources also have an effect on the system losses. The authors took minimization of system losses as one of the objectives. The other objective is to provide a better voltage profile.

Another optimal DG placement method to lessen the power loss of the system and improve voltage profile is presented by [23]. The method utilizes a combination of Radial Basis Neural Network and Partical Swarm Optimization. The added PSO ensures faster training for the Neural Network.

Maximum Loadability

While a system may be created to generate power essential to provide for the needs of an area. For a complete assessment of how much the system can handle under stress, a maximum loadability approach must be utilized. While increasing the load, the generators in the system must be capable of supplying to all loads without destabilizing the voltage profile or overloading the line limits.

Many approaches for maximum loadability have been utilized through time, with the most popular being continuation power flow [2]. The process of finding a continuum of power flow solutions starting at some base load and leading to the steady state voltage stability limit (critical point) of the system. The method entails use of a Predictor Step as the initial step of finding the next point of the solution then ultimately using Newton's Method (Corrector Step) to calculate the exact solution. The predictor and corrector steps are continued until the system reaches it critical point. The final result gives us the maximum loadability of the system.

Several other approaches for maximum loadability have surfaced through the years, where [10, 22, 33] are a few examples. [33] uses the Partical swarm optimization approach. The method is then compared to the already validated continuation power flow method. The particle swarm optimization is a simple method to assess maximum loadability of the system as no continuation parameter technique is needed to find the critical point. It directly finds the critical point of the system.

[22] takes a different direction, by first adding Distributed Generation into the system and then find the maximum loadability of the system. The Differential Evolution Algorithm method is implemented for the optimal sizing of Distributed Generation. The objective is to minimize DG cost and improve the maximization of the loadability value.

[10] takes the maximum loadability one step further. The authors increase the load of the system while running Optimal Power Flow. As we know, the OPF ensures all the system inequality constraints, such as voltage and line flow, to be within limits, while providing for the total load of the system. The advantage of this method is the OPF solution for the maximum loadability of the system. The resulting costs across all the buses (Locational Marginal Price) can be analyzed. at maximum load. This will help upgrade the system with DG placement or additional lines to the system.

1.2.2 Review of Distributed Generation

Using fossil and nuclear fuels, power systems have been able to supply variable loads from centralized generation sites. However, to maintain the same level of service to consumers, is quite clear that the world has to turn to Distributed Energy sources, mainly from Renewables. These dispersed generations are closer to the loads and fill the shortages otherwise not fulfilled by central generations. We are fortunate that research is being done in a wide range of renewable sources that could be integrated into the grid.

1.2.2.1 Hydroelectric

Hydroelectric power already has large scale integration into the grid. The use of dams to control the flow of large bodies of water is nothing new. The storage of water in such reservoirs allows generation to be timed to meet the load demands. Hydro heavily depends on rainfall which heavily depends on the season and the location. In countries such as Norway and Switzerland the hydro levels are so high they almost give away electricity for free. Another setback to hydro is building the dam itself. Not all topology favors these giant structures. Different scales of hydro power plants can be made, the largest being a dam and the smallest being installations called run of river schemes. These are small scale turbines that turn with the motion of the river. They are not as efficient and cannot be timed to produce the desired demand.

1.2.2.2 Wind

The flow of wind is caused by a lot factors, including the high and low pressure of the atmosphere, the spinning of the Earth (Coriolis force), and in certain location the differential heating of land and sea. Even the nature of the terrains such as valleys and mountains can bring about a change in the wind. Harnessing these wind speeds to create electricity can be a challenge. Because of the retarding forces impeding the wind near the Earth's surface, wind turbines have to be as tall as 100 meters to be most effective. Europeans have led the race in wind generation, with onshore wind resource estimated at 480 TWh/year. This trend is likely to continue as the European Union promises to generate around 965 TWh/year generation by the year 2030. To put it into perspective, this is equal to around 22.6% of the electricity requirements for the EU. Of all the renewable energy sources, wind power is the most developed. Sites with abundant wind can supply energy with costs similar to traditional generators. The many factors that give wind its strength are the same that gives its unpredicatability.

1.2.2.3 Solar

From solar, electricity can be derived in two ways. The first uses semiconductor devices to directly convert solar radiation into electrical energy. These semiconductors have an efficiency of 18%. The other method, solar thermal, utilizes the heat from the sun to convert water to steam. The steam is then used to turn turbogenerators to create electricity. The heat is concentrated either by parabolic troughs or thermal towers. The method of extracting energy from the two methodologies is quite different.

In the photovoltaic process, we have PV modules which absorbs solar radiation to produce DC current. Power electronics is applied to change the DC to AC current and then injected into the network. The power output of the PV module is determined from the I-V curve shown below, Figure 1.3. The maximum output is reached at the knee of the I-V characteristic curve, also known as the maximum power point. It is to be noted that both intensity (W/m^2) and temperature can alter the shape of the I-V characteristic curves and thus the Maximum Power Point (MPP), [18]. Electronics have to be devised to control and operate the voltage as close to the MPP as possible. These are commonly combined with the inverters used to create AC. But the slightest cloud can cause a rapid drop in the PV output.

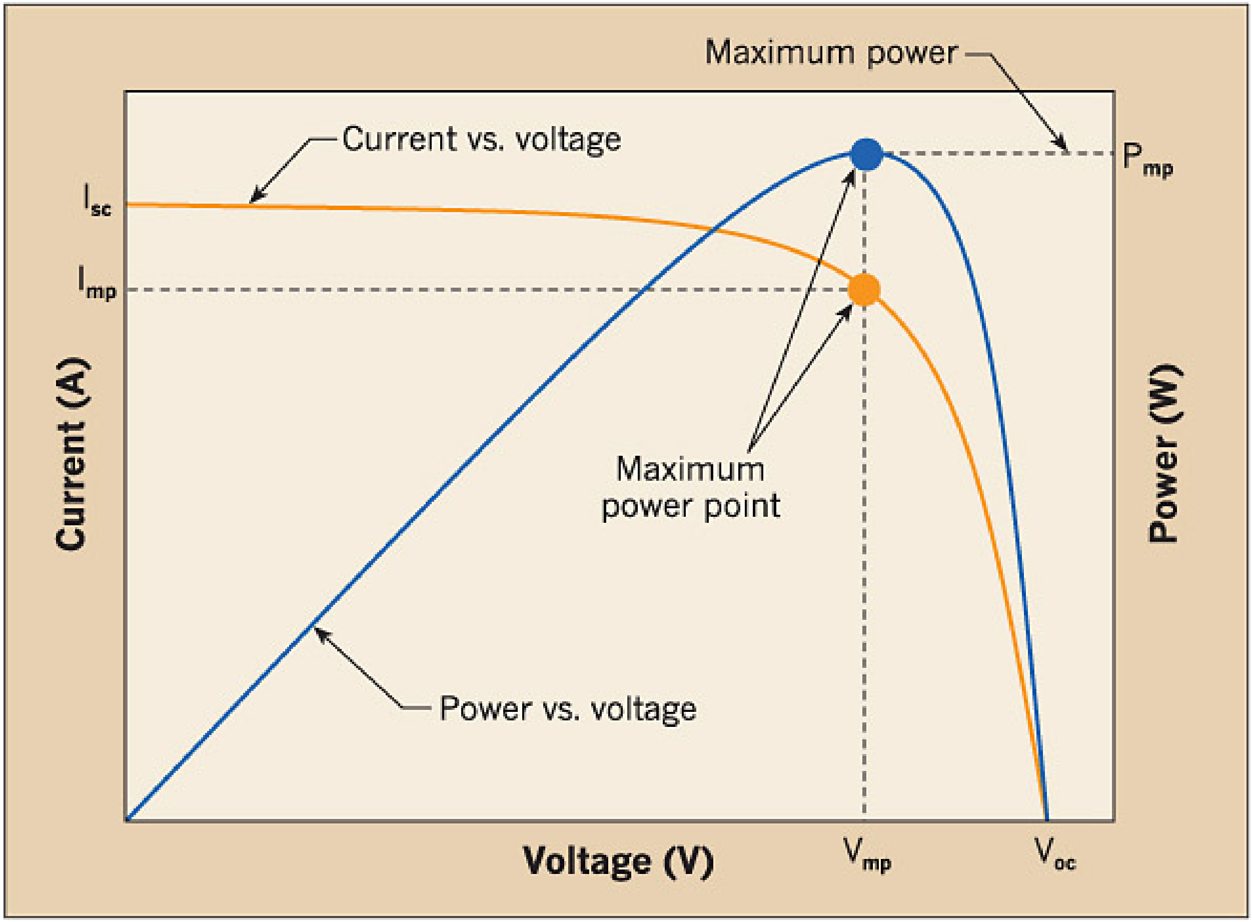


Figure 1.3: A typical IV curve showing the relationship of a module's current output plotted against the voltage output [1]

Two technologies exist to extract electricity from solar thermal technologies. The first is the solar farm. Here, the large collection of trough reflectors focuses the beams transferring the heat to a liquid intermediate. This liquid intermediate while hot is passed through the boiler to produce the necessary steam for the turbines. The other option is solar power towers surrounded by heliostats that send the concentrated heat to heat the intermediary liquid. Temperatures in solar tower plants can reach as high as 1000° C, much higher than solar farms, which typically reaches a maximum of 400° C. Also these towers are much more economical than solar farms, persuading installation of generation sites as large as 100MW in the future. Having an intermediary thermal stage in both the systems can be advantageous.

They can be combined with fossil fuel combustion to create a thermal storage system. The idea is to make the system dispatchable, thus enabling the system to provide electricity when the sun does not shine. Also unlike PV systems, the thermal to electricity has higher efficiency of around 20 − 40 %.

A summary of current renewable technologies, from [18], is listed below in table 1.2.2.3.

Energy Source	Typical unit size	Variable	Predictable	Dispatchable
Hydro with reservoir	Upto 500MW	NO	Yes	Yes
Pumped storage hydro	Upto 500MW	Yes	Yes	Yes
CHP	Upto 100MW	Usually	Usually	No, as it is heat led
Wind	Upto 5MW	Yes	Not accurately	No
Landfill gas	1MW	No	Yes	Yes
Photovoltaic cell	upto 100 KW (commercial)	Yes	Not accurately	No
Wave	No commercial example yet	Yes	Not accurately	No
Tidal	Not recent	Yes	Yes	No

Table 1.4: Generator characteristic by energy source

In this thesis, the distribution generation source will be independent of any type of renewable sources. A total of eight DG's have been selected [20], with varying costs to accommodate different DG sources currently available. DGs are considered as a conventional generator to avoid the problems of undispatchability, which is the predominant problem in so many of the renewable energy schemes.

1.3 Scope and Simulation tools

This thesis will take advantage of the solutions made available from Optimal Power flow to extract usable information that may assist power system planners to integrate to the design of their systems. Optimal power flow is an essential tool if the majority pushes towards deregulation. As stated earlier for a given system topology, the optimal power flow provides a solution so that the system can handle the hourly loads while not overwhelming line and generation constraints. And it does so while minimizing the total generation cost of the system. An optimal power flow will give the closest approximate solution to a system in steady state. The OPF is the best tool to carry out tests for system stability, maximum loadability, or optimal generation distribution. To ensure that any modification or addition to a particular system does not give any undesired outcomes, we turn to optimal power flow. An optimal power flow solution represents a fairly accurate mathematical model of the actual system.

In this thesis, we are going to utilize the modelling prowess of optimal power flow and make modifications to the system. Modifications which in the future will benefit the customer and/or the producer of a power system. The scope of this research is to obtain the best location to place a distributed generation source. A lot of research has been done on the proper placement of DG. A few have even utilized the functions of optimal power flow as well. This thesis looks at the economic changes caused by changes in load. It will provide answers to how the LMPs across the buses are affected to changes in load. Distributed generators will be used as a means to reduce this changes as much as possible. The placement of DGs depends on how well they achieve this task. The second objective of this thesis is to improve maximum load of the system. Any power system is bound to undergo stress. With population increasing on a day to day basis, it is wise to think ahead and evaluate systems on their loadability. Addition of a DG will increase the current loadability limit, thus ensuring generating electricity at the most economical and reliable manner possible. The simulations of OPF studies have been carried out in MATLAB.

MATLAB is a numerical computing environment designed to handle matrix manipulations. This feature along with its coding capabilities results in valuable toolboxes such as MATPOWER [36]. MATPOWER is an open source software developed by R. D. Zimmerman and C. E. Murillo-Sanchez from the Power Systems Engineering Research Center (PSERC) at Cornell University. MATPOWER was designed to give the best power flow and optimal power flow solution while being easy to understand and modify by researchers and educators alike. Optimal power flow is a nonlinear optimization problem with inequality constraints making it quite impossible to solve by conventional optimization procedures. This nonlinear optimal power flow is solved using the Interior Point Method (IPM) algorithm in MATPOWER. IPM is preferred due to its speed of convergence and ease handling of inequality constraints. The OPF objective and constraints are formulated in rectangular coordinates other than usual quadratic functions, thus giving some advantages. The objective of the OPF is to minimize the cost of production while making sure the demand matches the supply.

MATPOWER's solving capabilities and the author's own mathematical analysis will be used to find the optimal location for the distribution generators. Chapter 2 will include mathematical review of Optimal Power Flow, more specifically the methodology of Interior Point Method. The details of the author's mathematical analysis will be showcased in Chapter 3 of this thesis. The systems under study will be represented and compared in Chapter 4. The results of the various systems will be detailed in Chapter 5. Finally, a concluding chapter is added to discuss the usefulness of this study and if any future developments can be attained from it. The MATLAB programming has been added in the appendix for future reference.

Chapter 2

Mathematical Review

This chapter gives details about the formulation of Optimal Power Flow, how it is derived and by what methodology it is used to produce a solution. This chapter also includes the formulation of the Social Welfare Maximization that was covered in the previous chapter.

2.1 KKT condition

The KKT conditions are a set of criteria that need to be fulfilled to solve a nonlinear optimization problem. The method includes integrating the inequality constraints to the already existing Lagrange multiplier method, which works only for optimization problems with equality constraints. For optimal power flow to converge, this condition must be achieved in the intermediate steps.

Suppose we are given,

$$\min_{x \in R^n} f(x) \tag{2.1}$$

subject to

$$h_i(x) \leq 0, \quad i = 1, ...m$$

$$l_j(x) = 0, \quad j = 1, ...r$$

The Lagrangian is defined as :

$$L(x, u, v) = f(x) + \sum_{i=1}^{m} u_i h_i(x) + \sum_{j=1}^{r} v_j l_j(x) \tag{2.2}$$

Therefore the lagrange dual function is:

$$g(u, v) = \min_{x \in R^n} L(x, u, v) \tag{2.3}$$

And the subsequent dual problem becomes:

$$\max_{u \in R^m, v \in R^r} g(u, v) \tag{2.4}$$

subject to:

$$u \geq 0$$

2.1.0.1 Duality Gap

Given primal feasible x and dual feasible u, v, the quantity

$$f(x) - g(u, v) \tag{2.5}$$

is called the duality gap between x and u, v. Note that

$$f(x) - f^* \leq f(x) - g(u, v) \tag{2.6}$$

states that if the duality gap is zero, then x is primal optimal as well as making u,v dual optimal.

For iterative processes to solving the optimization problem,

$$f(x) - g(u, v) \leq \epsilon \tag{2.7}$$

serves as the criterion for the process to stop, as it makes sure that the following condition is met.

$$f(x) - f \leq \epsilon \tag{2.8}$$

Ultimately it boils down to these four conditions:

Stationarity:

$$0 \in \delta f(x) + \sum_{i=1}^{m} u_i \delta h_i(x) + \sum_{j=1}^{r} v_j \delta l_j(x) \tag{2.9}$$

Complementary slackness:

$$u_i . h_i(x) = 0, \quad for\ \ all\ \ i \tag{2.10}$$

Primal feasibility

$$h_i(x) \leq 0, l_j(x) = 0, for\ \ all\ \ i, j \tag{2.11}$$

Dual feasibility

$$u_i \geq 0, for\ \ all\ \ i \tag{2.12}$$

These conditions are absolutely necessary for the Interior point Method based solution of the Optimal Power Flow. Details of the Interior Point Method are given next.

2.2 Interior Point Method Formulation for Optimal Power Flow

MATPOWER [36] utilizes the widely used optimization technique, Interior Point Method, to solve the complex Optimal Power Flow problem. The objective function and the equality and inequality constraints are set up in a normal OPF problem.

For the compact version of the optimal powerflow we have,

$$\min \sum_{i=1}^{N_g} C_i(P_i) \tag{2.13}$$

$$G(x, u, y) = 0 \tag{2.14}$$

$$H(x, u, y) \geq 0 \tag{2.15}$$

where $C_i(P_i)$, $G(x, u, y)$, and $H(x, u, y)$ are assumed to be twice continuously differentiable. The IPM utilizes four steps to reach optimal conditions. First, all inequality constraints $H(x, u, y)$ are transformed into equality constraints shown below by the addition of slacks, given that slacks remain nonnegative.

$$H(x) - s = 0, \qquad s \geq 0 \tag{2.16}$$

Here, the vectors x and $s = [s1, s2, \ldots\ldots, sq]^T$ are called primal variables.

In the second phase, the new inequality constraints are then eliminated by introducing them as logarithmic barriers in the objective function. This results in an equality constraint optimization problem.

$$\min f(x) - \mu \sum_{i=1}^{q} ln\ s_i \tag{2.17}$$

subject to: $G(x) = 0$ and $H(x)$–$s = 0$

μ is a special scalar called the barrier parameter. This μ is gradually decreased to zero as the iteration progresses and according to the KKT conditions we reach the optimal solution of x^* as μ reaches zero.

The third step of the IPM is to transform the equality constrained optimization problem into an unconstrained one. This is done by defining the Lagrangian:

$$L_\mu(y) = f(x) - \mu \sum_{i=1}^{q} ln\ s_i - \lambda^T g(x) - \pi^T [h(x) - s] \tag{2.18}$$

where the vectors of the Lagrange multipliers λ and π are called dual variables and $y = [s, \pi, \lambda, \mu]^T$.

Finally the perturbed KKT first-order necessary optimality conditions of the resulting problem are obtained by setting to zero the derivatives of the Lagrangian with respect to all unknowns:

$$\begin{bmatrix} \nabla_s L_\mu(y) \\ \nabla_\pi L_\mu(y) \\ \nabla_\lambda L_\mu(y) \\ \nabla_x L_\mu(y) \end{bmatrix} = \begin{bmatrix} -\mu e + S\pi \\ -h(x) + s \\ -g(x) \\ \nabla f(x) - J_g(x)^T \lambda - J_h(x)^T \pi \end{bmatrix} = 0 \tag{2.19}$$

where S is a diagonal matrix of slack variables, $e = [1, , , , , , 1]^T$, $\nabla f(x)$ is the gradient of f, $J_g(x)$ is the Jacobian of $g(x)$ and $J_h(x)$ is the Jacobian of $h(x)$.

From [7] the steps to solve the previous KKT optimality condition are highlighted below.

1. Starting from k=0, the initial values for μ, y > 0 are chosen, keeping in mind that

   (s^0,π^0) > 0.

2. The linearized KKT conditions is then solved for the Newton Direction $\Delta\ y^k$. Here

H(y^k) equals $\frac{\delta^2 L_\mu(y^k)}{\delta y^2}$

$$H(y^k)\begin{bmatrix}\Delta s^k\\ \Delta\pi^k\\ \Delta\lambda^k\\ \Delta x^k\end{bmatrix} = \begin{bmatrix}\mu^k e - S^k\pi^k\\ h(x^k)+s^k\\ g(x^k)\\ -\nabla f(x^k)+J_g(x^k)^T\lambda^k+J_h(x^k)^T\pi^k\end{bmatrix} = 0 \qquad (2.20)$$

3. Determine the maximum step length α^k ϵ (0,1] along the Newton direction Δy^k such that (s^{k+1},π^{k+1}) > 0

4. A (locally) optimal solution is found and the optimization process terminates when: primal feasibility, scaled dual feasibility, scaled complementarity gap and objective function variation from an iteration to the next fall below some tolerances.

5. If convergence was not achieved, the barrier parameter, $\mu^{k+1} = \sigma\frac{p^k}{q}$ by making k = k+1 and go back to step 2. Here σ =0.2.

Note that, the dual variables at the optimal solution yield very precious information. They are equal to the sensitivity of the objective to a small constraint shift. In particular, the dual variable (Lagrange multiplier) associated with each active power flow equation represents the variation of the overall generation cost for an increment of the active load at that bus. They are called nodal prices and used as a method of pricing in some deregulated electricity market [6].

2.3 Social Welfare Maximization

Maximization of social welfare benefits both the consumers and producers in the electricity market scenario. As earlier stated, the social welfare objective function is the difference between the quadratic benefit bid curve and the quadratic cost curve, giving the following equation.

$$\max \sum_{i=1}^{N} B_i(P_{Di}) - C_i(P_{Gi}) - C_i(P_{DGi}) \tag{1.3}$$

The graphical representation of the above equation is shown in Figure 2.1. The social welfare is the summation of the consumer surplus and the producer surplus.

The first phase of finding the social welfare is to solve the Optimal Power Flow of the test system. The solution of the objective function will be the minimum price incurred by the producers to generate the electricity for that load.

The total benefit is then calculated using the benefit function represented for each bus. Similar to fuel cost functions, the benefit function is dependent on the load. Finding the benefit costs and then the total social welfare of the system uses simple arithmetic.

The process is to repeat the steps of finding the social welfare while placing a distributed generator at different bus locations. The ideal DG location would be where the social welfare is the highest, benefiting both consumer and producer the most.

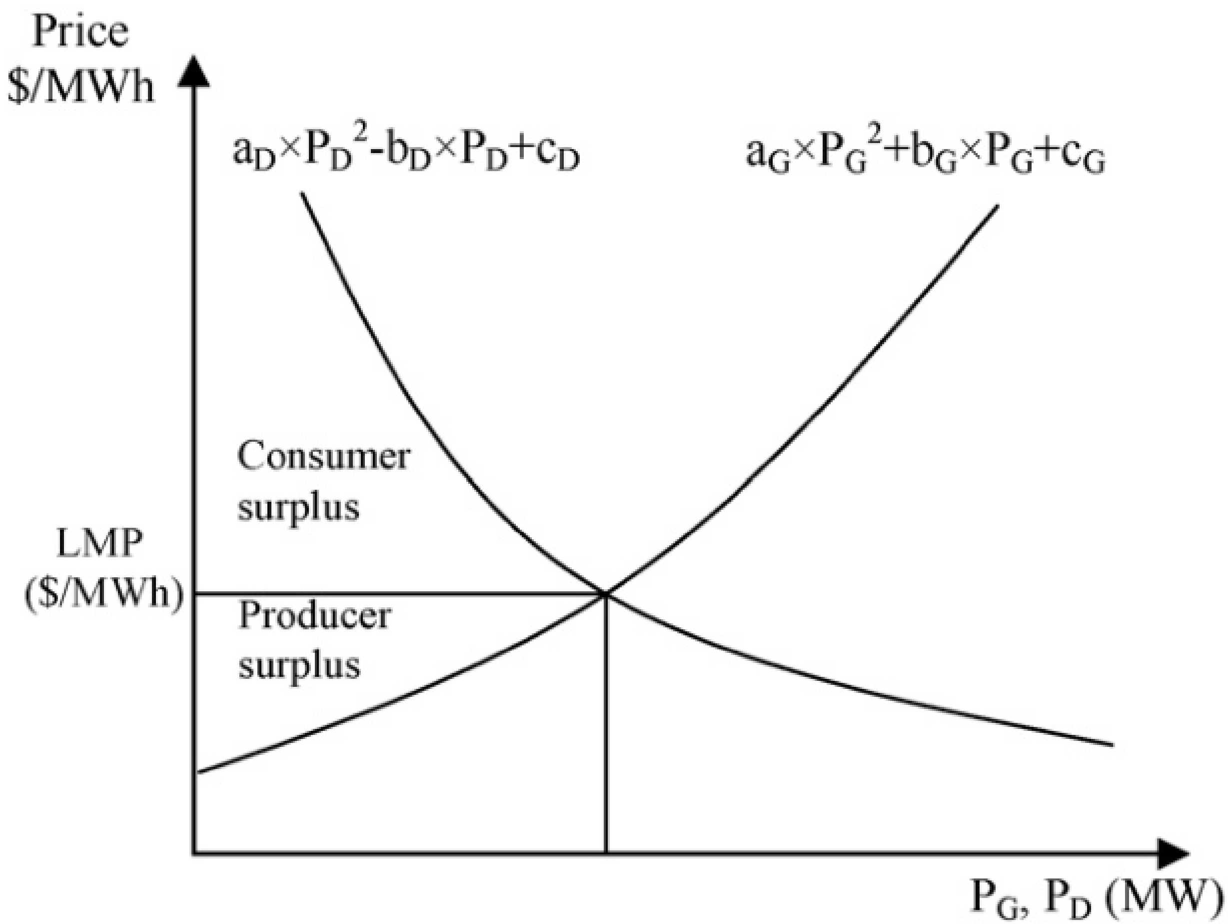


Figure 2.1: Social surplus with quadratic supply and demand curves [20]

Chapter 3

Thesis Contribution

3.1 Problem Statement: Ideal Location for Distributed Generation Placement

Placement of distributed generation in an existing power system can be quite a challenge. The ideal location is subject to much speculation and study from the scientific community. With various insights and opinions, advantages and disadvantages, quite a few papers have been published. Some looked to reduce power losses and improve voltage stability. Other objectives included reducing fuel costs or improving profit made by the Producer.

Many papers discuss using the capabilities of the distributed generation to maximize the loadability of the system, thus effectively reduce load shedding. The term, Social Welfare is the summation of Consumer surplus and Produce surplus. With power systems increasingly moving towards deregulation, it should not be a surprise that studies are conducted to benefit both customer and producer and maximizing the Social Welfare achieves that. Much of these research does not include the true representation of the real system, however. This thesis will address this drawback and come up with results that support the ideal location to place a Distributed Generator.

3.2 Methodology

The objective of this thesis is to correctly identify the best location to place a distributed generator. The selection will be made through a multitude of tests. All the tests are conducted using the optimal power flow technique. A system optimized by optimal power flow is nearly identical to a real system as an OPF includes all the security constraints neglected in regular power flow. The criterion that have been chosen to determine the ideal location are:

1. Criterion 1: Load Maximization
2. Criterion 2: Distributed Generation Utilization
3. Criterion 3: Locational marginal Price Tracking using root mean square
4. Criterion 4: Line contingency: N-1 and N-2.
5. Criterion 5: Social Welfare Maximization

A distributed generator is placed at one bus location and used to determine the results of the above said criterion. The DG will be moved from bus to bus, to determine the best outcome of the results. For criteria 1 to 4, the results are all interconnected for the test system. Criteria 5 uses a separate technique and will be presented later.

3.2.1 Load Maximization

The idea is to determine the maximum load the system can support while considering system limits. This can be done in the optimal power flow setting, where a system runs while considering all the security constraints. The process starts from 30 percent of the total load of the system and gradually increases the load until the system collapses. The base case of 30% load was chosen as a safe initial load to guarantee convergence.

As previously mentioned the simulations will be run while placing the distributed generator at one bus. Then the process repeats with the DG placed at a different bus. The objective is to find the ideal location that helps the system expand its maximum load limit. The system will be able to reduce load shedding if it is able to maximize its load support.

3.2.2 Distributed Generation Utilization

Apart from the proper location of DG placement, the sizing of the DG is just as important. With the advent of many distributed generation technologies, one cannot limit the study to just one type of DG, at least in terms of cost. Some DG technologies are not as cheap as traditional generators. The objective here is to satisfy all the intended criterion while keeping the usage of DG to a minimum. Therefore, it is very important the optimized amount of DG is being injected into the system. This will be optimized by the Optimal Power Flow tool in MATPOWER as well.

3.2.3 Locational Marginal Price Tracking using Root Mean Square

Locational Marginal Price is used as a method of pricing in many deregulated electricity markets. Another aim of this Thesis is to look at how LMP is affected with load variability. The process involves finding the difference between the current iteration LMP and the base case (30 percent) of the total load. The root mean square of this difference is recorded to measure the overall difference between the two LMPS. The RMS depicting the difference at each load increase is thus found.

Suppose for the i^{th} load increase above the base case load level (i $>$ 30) we get the following LMP values of buses 1 through n:

$$LMP^i = \begin{bmatrix} LMP_1^i \\ LMP_2^i \\ LMP_3^i \\ \cdots \\ \cdots \\ LMP_n^i \end{bmatrix} \tag{3.1}$$

And we already have the LMP set for the base case system,

$$LMP^{30} = \begin{bmatrix} LMP_1^{30} \\ LMP_2^{30} \\ LMP_3^{30} \\ \cdots \\ \cdots \\ LMP_n^{30} \end{bmatrix} \tag{3.2}$$

τ = LMP^i - LMP^{30} will give the difference between the two sets. Taking the RMS of this result will quantify the overall difference of the two sets by a single number. With each load increase we will understand how the LMP is affected by RMS(τ). Since RMS is always a positive value, it makes it difficult to distinguish whether the RMS value indicates a rise or fall in LMP values. To ensure correct representation of RMS(τ), vector τ is used once more. Individual values of τ are summed together. A negative sum suggests a fall in overall LMP and a positive sum indicates that the LMP values overall increase at that particular iteration. The sign is indicated by ρ, which can be +1 or -1, depending on the sign of the summation. Therefore the overall change in LMP is reflected by $\rho \times$ RMS(τ). Figure 3.1 outlines the procedure. The flowchart focuses on the IEEE 14 bus test case.

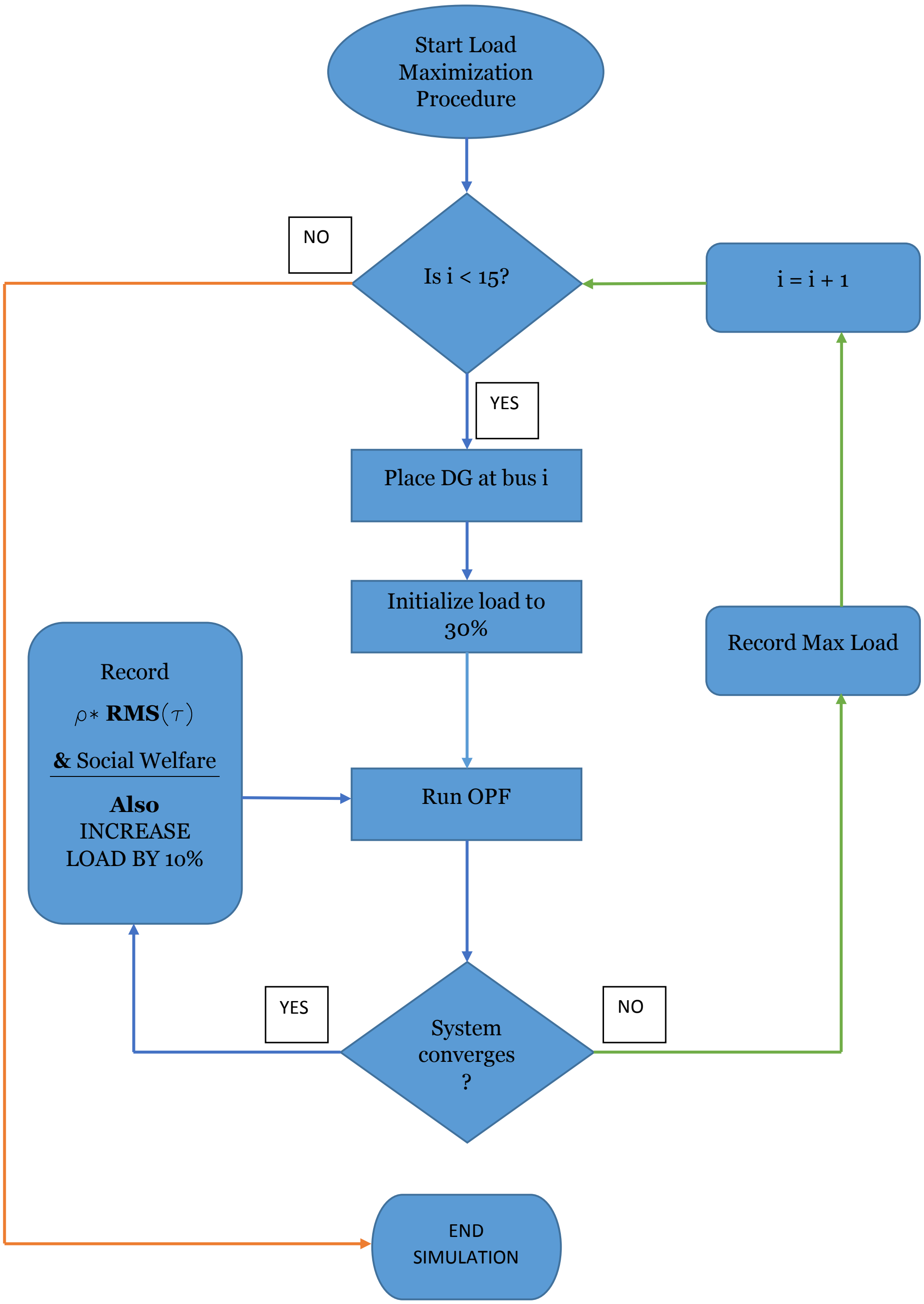


Figure 3.1: Flowchart for the process of (i) Max Load, (ii) LMP tracking and (iii) Social Welfare tracking

3.2.4 Line contingency: N-1 and N-2

A system must provide electricity at all times. It must ensure security and reliability at all times. This brings us to line contingencies. This thesis analyses how proper DG installation can uphold both N-1 and N-2 line contingencies. For N-1 contingencies, the system is subjected to one line outage at a time, while also placing DG at a particular bus. The aim is to continue running the system at the intended load level. The system continuing to run even though a line is dropped will be considered a pass. The best scenario is when the DG placement ensures the maximum number of passes after subjecting the system under all line contingencies.

The N-2 contingencies, implemented by dropping two lines at a time, can lead to a combination of C(n,2) = n! / (2! (n - 2)!), where n is the total number of lines. Again, the maximum number of passes will determine the winning location to place the distributed generator. Figures 3.2 and 3.3 highlight the steps followed in the N-1 and N-2 line contingency testing respectively. The figures reflect the system used in this study, the IEEE 14 bus system with 20 lines.

As Figure 3.2 shows, a DG is placed in one location and the OPF is performed while removing one line at a time. In every iteration 19 lines out of 20 are connected. The number of passes out of the 20 line contingencies are recorded. For each DG location there are 20 iterations, making a combined total of $20 \times 14 = 280$ iterations of OPF runs.

The number of N-2 contingency combinations for the 20 lines equals C(20,2) = 190 scenarios. The number of passes out of the 190 line contingency scenarios are recorded. In the flowchart of Figure 3.3, line j and line j+n are both removed. Here $1 \leq j,n \leq 19$. Along with the previous condition of $j \leq 20$, we also have $j+n \leq 20$. For example, if we remove line $j = 1$, the additional line to be removed will be $j+n = 2$. So lines 1 and 2 together will be removed in this scenario. If $j = 19$ then line 19 and line $j+n = 20$, will be removed. Each iteration stops when all of 190 line removal scenarios are simulated. So a total of 190×14

= 2660 OPF simulations are made for the N-2 contingency test.

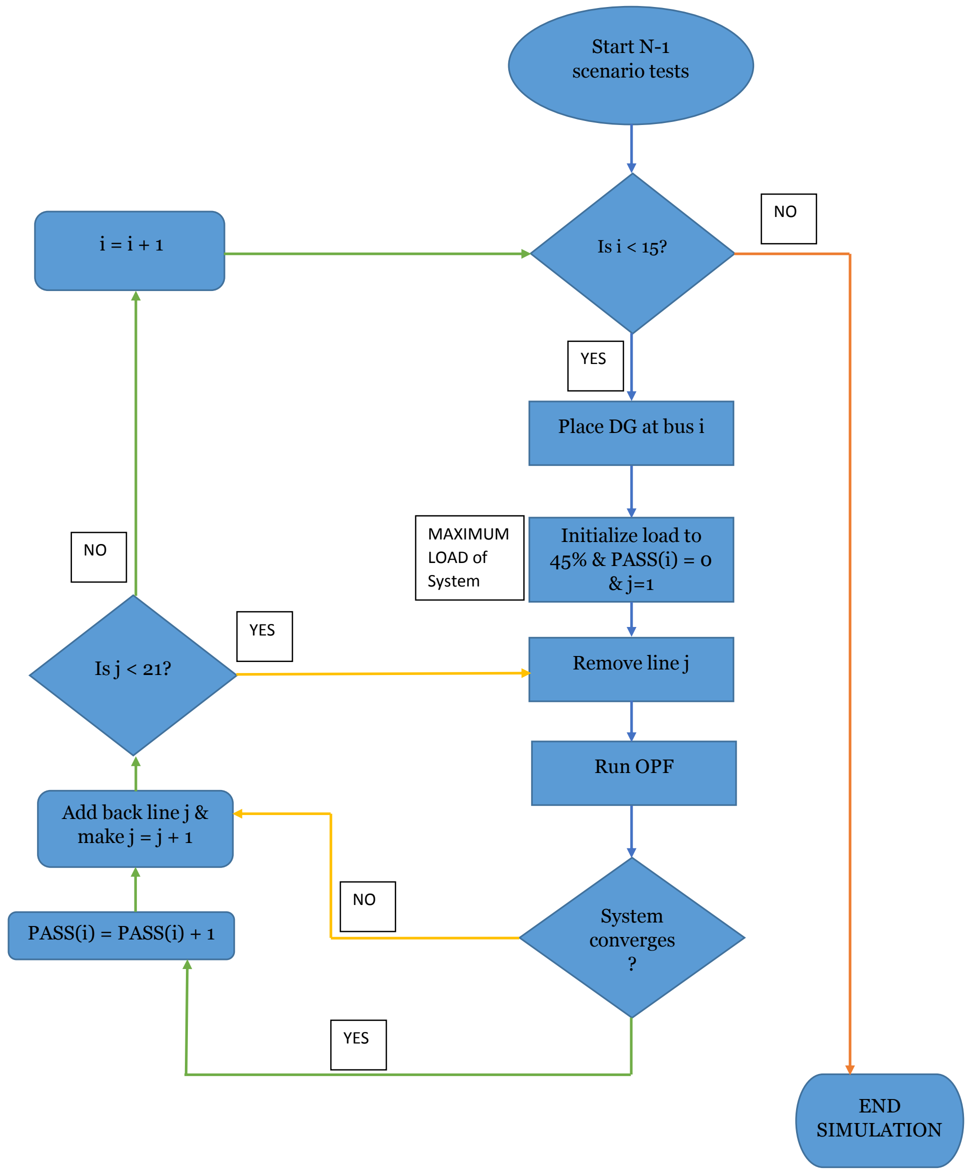


Figure 3.2: Flowchart for the N-1 contingency testing

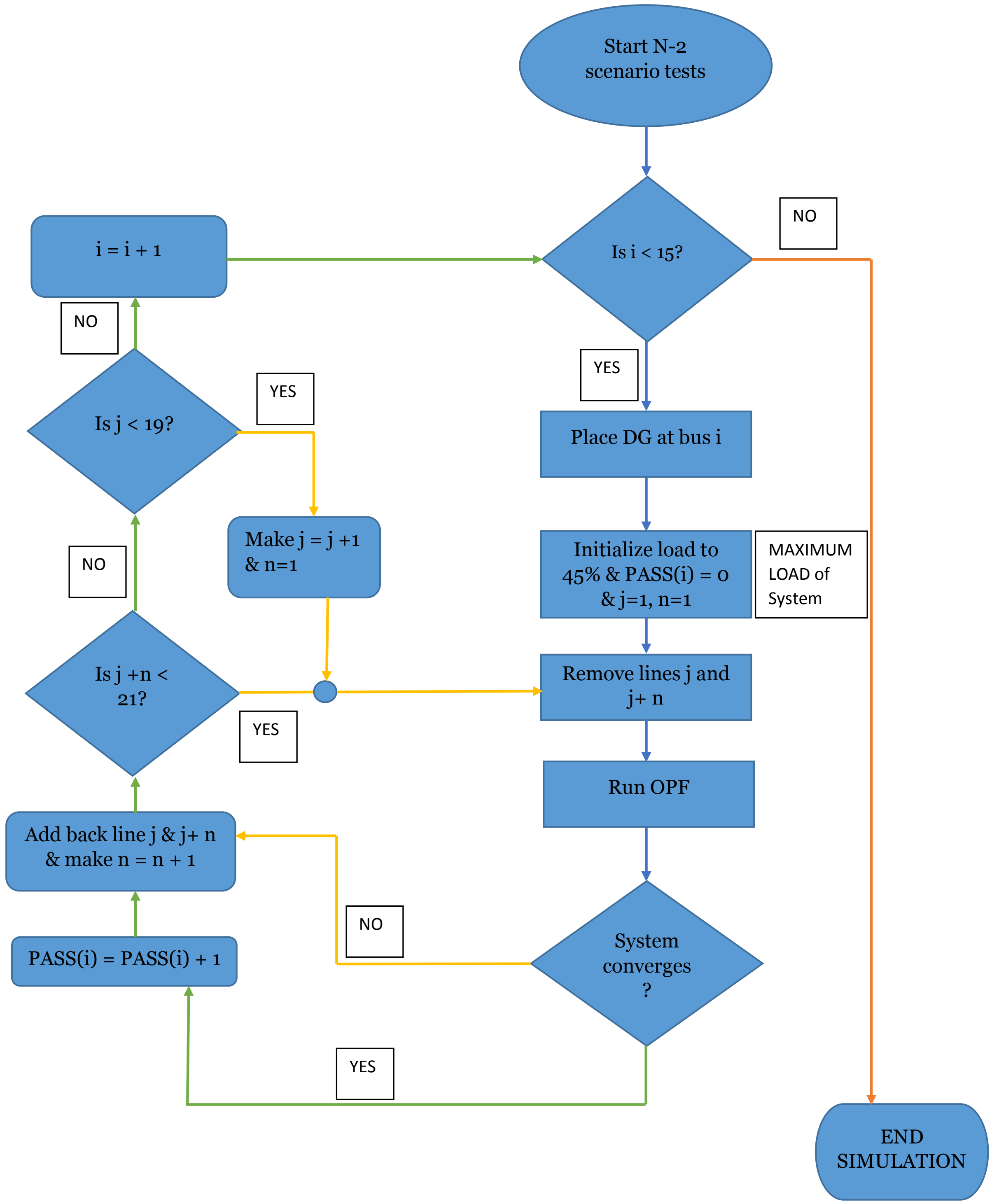


Figure 3.3: Flowchart for the N-2 contingency testing

3.2.5 Social Welfare Maximization

From [19], it was learned that the best location to place a distributed generator was where the most Social Welfare is obtained. In this Thesis, the same procedure is followed. However, the Social Welfare is found while increasing the load (alongside criteria 1 and 3, refer to fig 3.1). This helps determine if the same bus will present the highest Social Welfare with the variation in load. The optimization of the objective function below is repeated until the system collapses.

$$\max \sum_{i=1}^{N} B_i(P_{Di}) - C_i(P_{Gi}) - C_i(P_{DGi}) \tag{1.3}$$

3.3 Justification of using distributed generation

All of the criteria will be first tested in the system without any DG present. The system needs to be tested for its maximum loadability, the loss incurred during generation as well as the change in LMP prices. Then at the system's maximum capacity it will be tested for the N-1 and N-2 contingencies. The systems maximum load is nearer to system collapse, giving a probable scenario for N-1 and N-2. The results will be compared to the ones generated from the presence of DGs, then the objectives of this thesis will be fulfilled.

Chapter 4

Test Systems

This chapter covers the test systems that were used to test out the methodologies described in the previous chapter.

4.1 Description of test system

Most of the simulations were done on two variants of the IEEE 14 bus system. The difference between the two systems is the distribution of loads in the 14 buses. As there are no line limits in the original 14 bus system, a suitable set of values was imported from [28]. The 14 bus is unique as not only does it have 3 generators; it also has 2 synchronous condensers for VAR support. The 14 buses are interconnected by 20 transmission lines. The system is presented below in Figure 4.1. The specifications for generators and transmission lines are given below. Two sets of load distribution are taken into consideration for the simulations. They will also be presented later in this chapter.

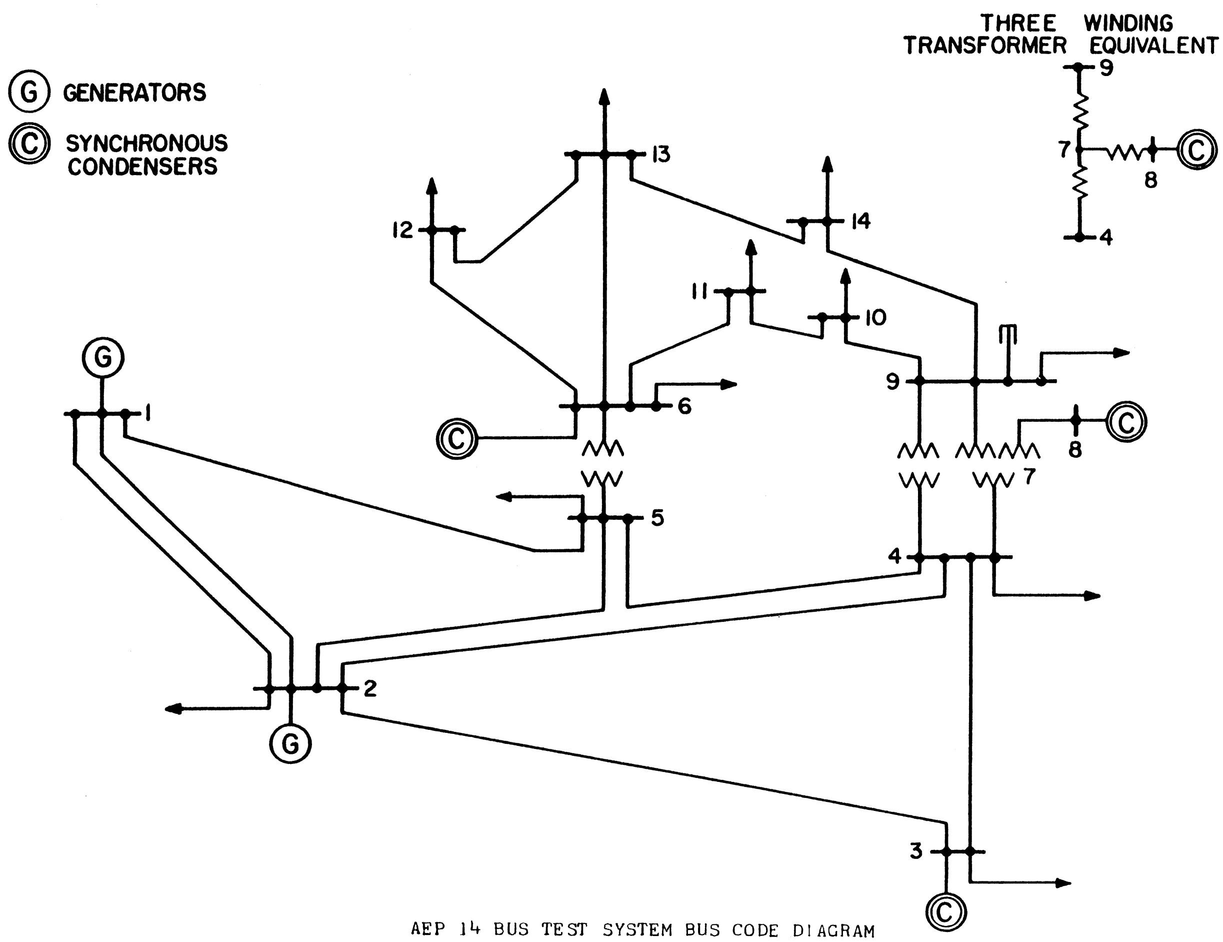


Figure 4.1: 14 bus test system

4.2 Generator Cost Data

The three generators of the 14 bus test system are priced quite differently. The difference in price affects the generation from each source as the main objective of OPF is to minimize the fuel costs. This would limit high priced generators from producing more unless absolutely necessary.

As mentioned above, the 14 bus system has two synchronous condensers and those are located at buses 6 and 8. The prices of the 5 machines are presented below in Table 4.1. In MATPOWER all types of generators are treated the same, having the generic components a, b and c.

Generator no	Bus Location	a	b	c
1	1	0.0430292599	20	0
2	2	0.25	20	0
3	3	0.01	40	0
4	6	0.01	40	0
5	8	0.01	40	0

Table 4.1: 14 bus generator cost data

4.3 Generation Production Data

Aside from the cost data, generation limits have to be considered to optimize the system to function at minimum cost. Details of the generation are given in Table 4.2.

bus	Vg	mBase	status	Pmax	Pmin	Qmax	Qmin
1	1.06	100	1	332.4	0	10	0
2	1.045	100	1	140	0	50	-40
3	1.01	100	1	0	0	40	0
6	1.07	100	1	0	0	24	-6
8	1.09	100	1	0	0	24	-6

Table 4.2: 14 bus generator production data

4.4 Transmission line data

The locational marginal price is dependent on three factors, the price of fuel, the price due to loss and lastly the price of congestion. The congestion costs are driven by the thermal limits of the transmission system. The original 14 bus system did not have any line flow limits included and the limits included in this work are from [28]. The line limits are absolutely necessary to make the power flows in the transmission line as close to the real system as possible. The details of line parameters and line limits are in Table 4.3.

Line No	Bus from	Bus to	r	x	b	MVA rating
1	1	2	0.01938	0.05917	0.05280	120
2	1	5	0.05403	0.22304	0.04920	65
3	2	3	0.04699	0.19797	0.04380	36
4	2	4	0.05811	0.17632	0.03400	65
5	2	5	0.05695	0.17388	0.03460	50
6	3	4	0.06701	0.17103	0.01280	65
7	4	5	0.01335	0.04211	0.00000	45
8	4	7	0.00000	0.20912	0.00000	55
9	4	9	0.00000	0.55618	0.00000	32
10	5	6	0.00000	0.25202	0.00000	45
11	6	11	0.09498	0.19890	0.00000	18
12	6	12	0.12291	0.25581	0.00000	32
13	6	13	0.06615	0.13027	0.00000	32
14	7	8	0.00000	0.17615	0.00000	32
15	7	9	0.00000	0.11001	0.00000	32
16	9	10	0.03181	0.08450	0.00000	32
17	9	14	0.12711	0.27038	0.00000	32
18	10	11	0.08205	0.19207	0.00000	12
19	12	13	0.22092	0.19988	0.00000	12
20	13	14	0.17093	0.34802	0.00000	12

Table 4.3: 14 bus transmission line data

4.5 Load data

In this thesis, instead of using a different test system, the 14 bus system's load distribution was modified to represent an alternate load scenario and was used to test how it will affect the position of DG placement.

4.5.1 Load Distribution A (System A)

This load distribution belongs to the IEEE 14 bus system case. Details are presented next in Table 4.4. The total load of the system is 259 MW.

Bus	type	Pd	Qd	Vm	Va	Vmax	Vmin
1	3	0	0	1.06	0	1.06	0.94
2	2	9.765	12.7	1.045	-4.98	1.06	0.94
3	2	42.39	19	1.01	-12.72	1.06	0.94
4	1	21.51	-3.9	1.019	-10.33	1.06	0.94
5	1	3.42	1.6	1.02	-8.78	1.06	0.94
6	2	5.04	7.5	1.07	-14.22	1.06	0.94
7	1	0	0	1.062	-13.37	1.06	0.94
8	2	0	0	1.09	-13.36	1.06	0.94
9	1	13.275	16.6	1.056	-14.94	1.06	0.94
10	1	4.05	5.8	1.051	-15.1	1.06	0.94
11	1	1.575	1.8	1.057	-14.79	1.06	0.94
12	1	2.745	1.6	1.055	-15.07	1.06	0.94
13	1	6.075	5.8	1.05	-15.16	1.06	0.94
14	1	6.705	5	1.036	-16.04	1.06	0.94

Table 4.4: Load distribution data A

4.5.2 Load Distribution B (System B)

Another variant of the load distribution was found in [19] which totals a demand of 323.5 MW. Table 4.5 shows the details of load at each bus.

Bus	type	Pd	Qd	Vm	Va	Vmax	Vmin
1	3	0	0	1.06	0	1.06	0.94
2	2	3.6765	12.7	1.045	-4.98	1.06	0.94
3	2	19.3005	19	1.01	-12.72	1.06	0.94
4	1	25.2225	-3.9	1.019	-10.33	1.06	0.94
5	1	11.934	1.6	1.02	-8.78	1.06	0.94
6	2	16.02	7.5	1.07	-14.22	1.06	0.94
7	1	8.9505	0	1.062	-13.37	1.06	0.94
8	2	0	0	1.09	-13.36	1.06	0.94
9	1	11.817	16.6	1.056	-14.94	1.06	0.94
10	1	5.6925	5.8	1.051	-15.1	1.06	0.94
11	1	17.856	1.8	1.057	-14.79	1.06	0.94
12	1	5.031	1.6	1.055	-15.07	1.06	0.94
13	1	4.815	5.8	1.05	-15.16	1.06	0.94
14	1	15.2595	5	1.036	-16.04	1.06	0.94

Table 4.5: Load distribution data B

4.6 Distributed Generation Data

Two types of DG, DG1 and DG2, will be considered in this thesis. The cost of DG1 is lower than the traditional generators in the 14 bus system, whereas DG2 will be the more expensive option. Since Optimal Power flow optimizes the fuel cost, it will be interesting how the two polarizing DGs will affect the results of the criteria mentioned in Chapter 3. The difference in price of the two DG's in this thesis envelopes the varying prices of the multitude of distributed generation technologies available at the present time. Given below is the information for the two DG systems.

DG	a	b	c	P_{min}	P_{max}
1	0.002	15	0	0	500
2	0.003	43	0	0	500

Table 4.6: DG cost and generation Data

P_{min} and P_{max} values are taken as such to ensure that the OPF program can optimize the usage of DG generation freely and has the option to close off DG input if the price becomes too high.

Chapter 5

Results and Discussion

5.1 14 bus system Initial Analysis

Comparing the results of the actual 14 bus system with the one having a distributed generator is essential for the justification of inclusion of DG. As mentioned in the previous chapter, two different load distribution is present for the 14 bus test system. This chapter will begin with the results of the two distinct system with no DGs present. Then it will move on to simulations that include DGs. All of the simulations are run using MATPOWER's Optimal Power Flow simulation.

5.1.1 Load Distribution A

The first phase is to figure out the max load the system can support. The load level rises from 30 % of the total system load (77.7 MW of 259 MW) and stops when system collapses. While the simulation runs the change in LMP is tracked using the $\rho \times$ RMS value at each load level.Figure 5.1 showcases the result of load variability and LMP variation on system A.

From the figure it is evident that the price of LMP from zero keeps risings steadily but

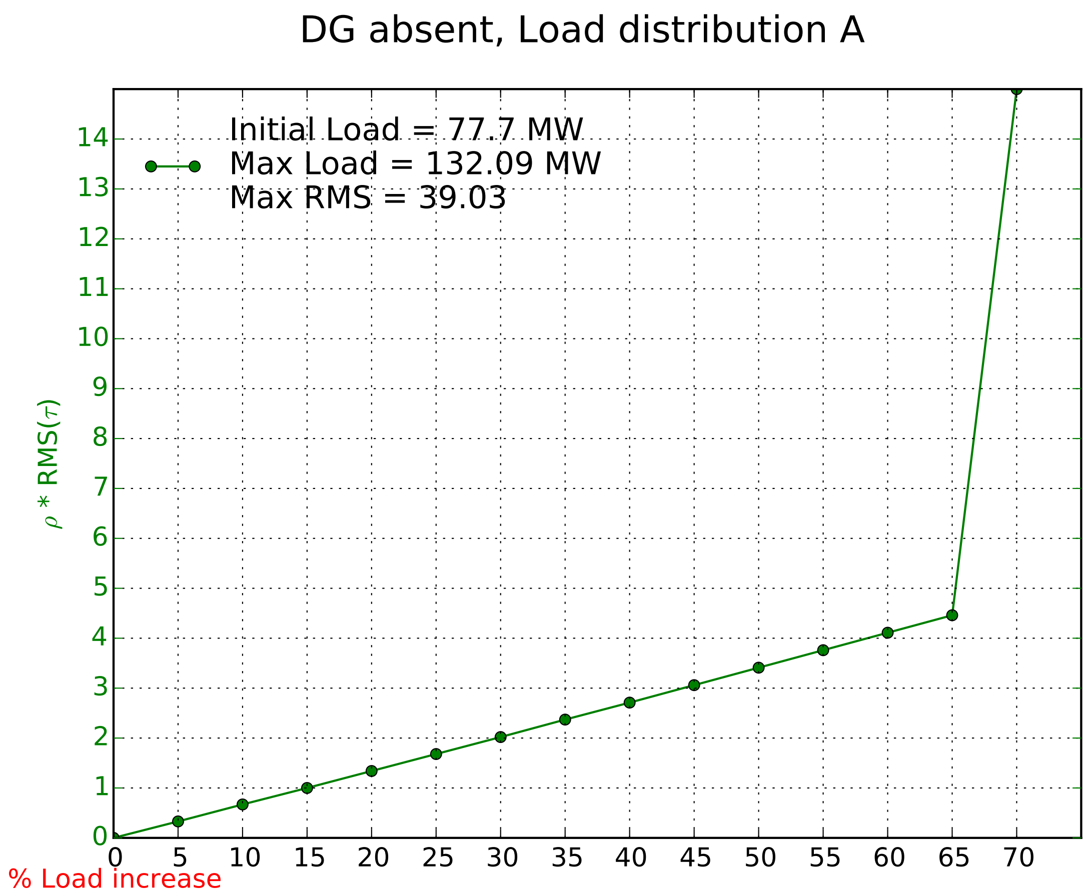


Figure 5.1: Variation in LMP with each load increase, System A

skyrockets at the end. It is also the point where the system loses its stability and we are no longer able to supply more load. The maximum load the system can support is 132.09 MW. The initial value zero occurs as LMP^i - $\text{LMP}^{30} = 0_{[14,1]}$.

At the maximum load point of 132.09 MW, the system is tested for N-1 and N-2 contingency. The IEEE 14 bus system has altogether 20 transmission lines. For the N-1 contingency, there are total 20 iterations of line removal to check the security strength of the system. The system could only pass 12 of the 20 line removals.

In N-2, given that 2 lines need to be shut of simultaneously, there are a total of C(20,2) = 20! / (2! (20 - 2)!) = 190 combinations of line contingencies. From the 190 combinations, the system could only pass 70.

5.1.2 Load Distribution B

System B has a total load of 323.5 MW. The simulation is started from 30 % of the total. The previous processes are then repeated.

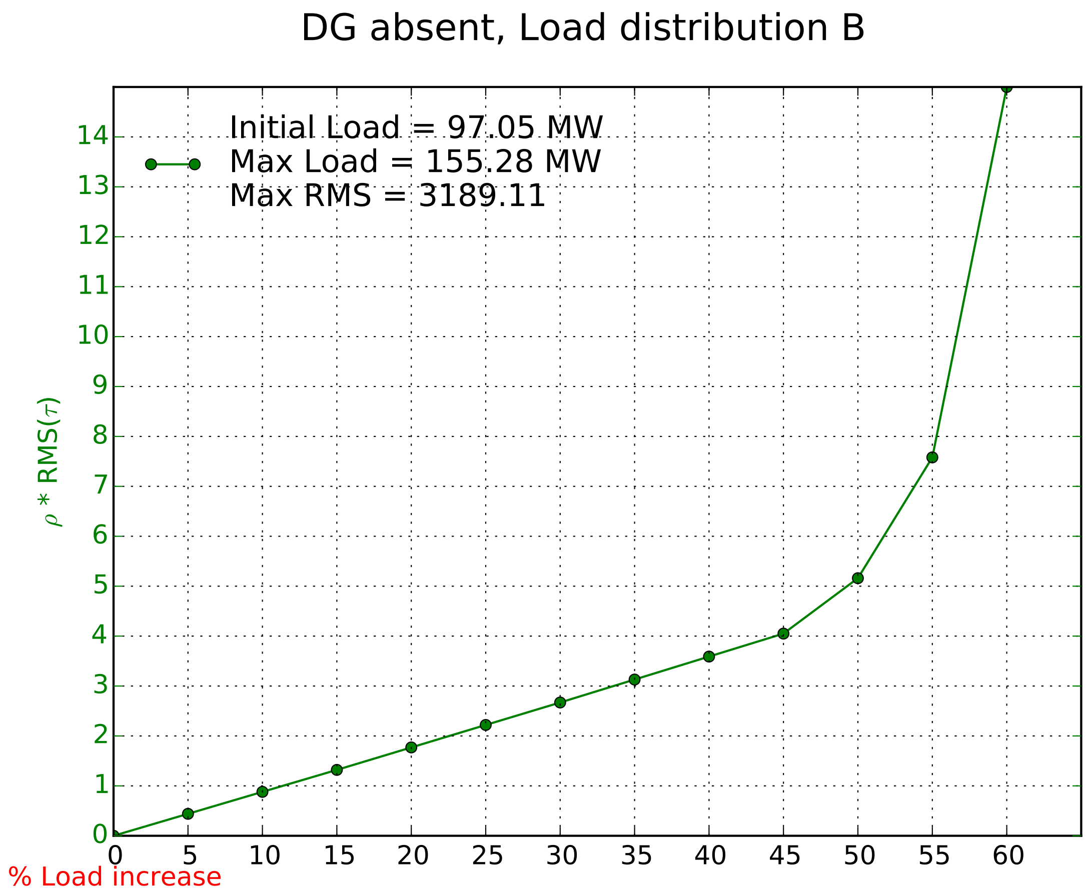


Figure 5.2: Variation in LMP with each load increase, in terms of the RMS, System B

The $\rho \times$ RMS reaches an astonishing value at the critical point of the system. The system collapses after the total load increases to 155.28 MW. The system at this critical load only passes 7 of the 20 N-1 line contingency scenarios. Even worse out of the 190 N-2 line contingency scenarios, it only passes 28 scenarios.

The two systems are in need of support to maximize loadability and ensure greater reliability. The rest of the thesis will discuss the improvements that will be achieved by installing a distributed generator at the ideal location. The next section will reintroduce the criterions discussed in chapter 3 with the added results.

5.2 Load Distribution A with DG1 installation

Criterion 1 through 5 will be tested out to find the ideal location to install a DG. The initial phase as before is testing the maximum load of the system.

5.2.1 Load Variability and LMP tracking

From 30 %, the load will be increased bit by bit until the system reaches its limit. The ideal placement of distributed generator is the bus where the final load of the system is the highest. Keep in mind we are testing the results using two separate DGs, one more expensive than the other.

The first set of results will be of the least expensive one, DG1. In the initial stages of load increase, the $\rho \times$ RMS is negative. This is to be expected as there is now a third cheaper generator (DG1) supplying part of the total load. This occurrence is noticed for DG1 placed at every bus. The system is optimized by the cheaper alternative, driving down prices across every bus. Though after an extent the normal rise in price comes into play. And the graphs follow the natural upward swing.

The graphs consists of two paths, a **green** curve that follows a natural increase in $\rho \times$ RMS. The corresponding values for the green curve is on the left of the y-axis in **green**. And another **red** curve that showcases the extreme rises in Locational Marginal Price. The extreme values are on the right of y-axis in **red**. These color coding will be followed throughout the rest of this thesis.

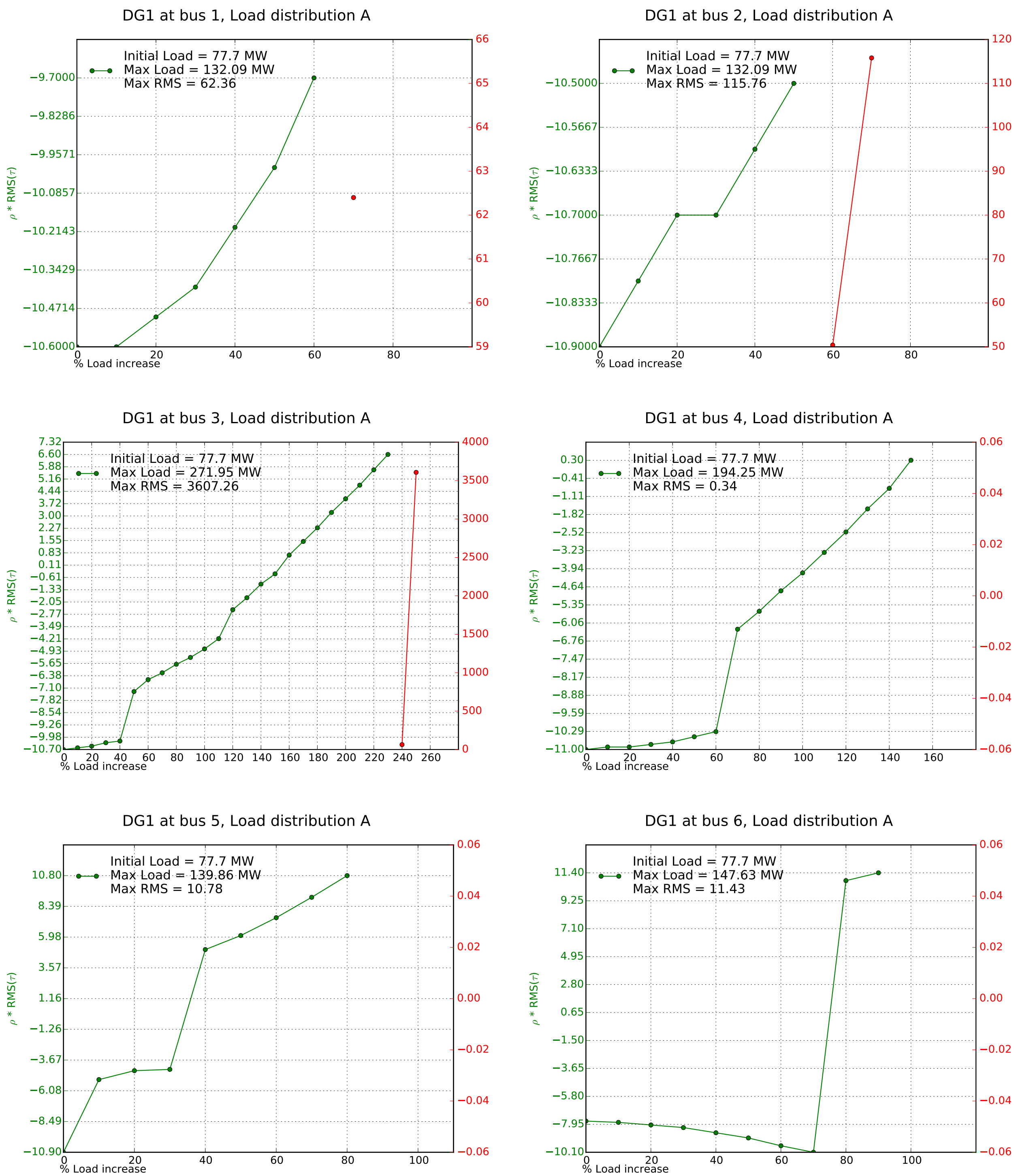


Figure 5.3: DG1 installation results buses 1 through 6, System A

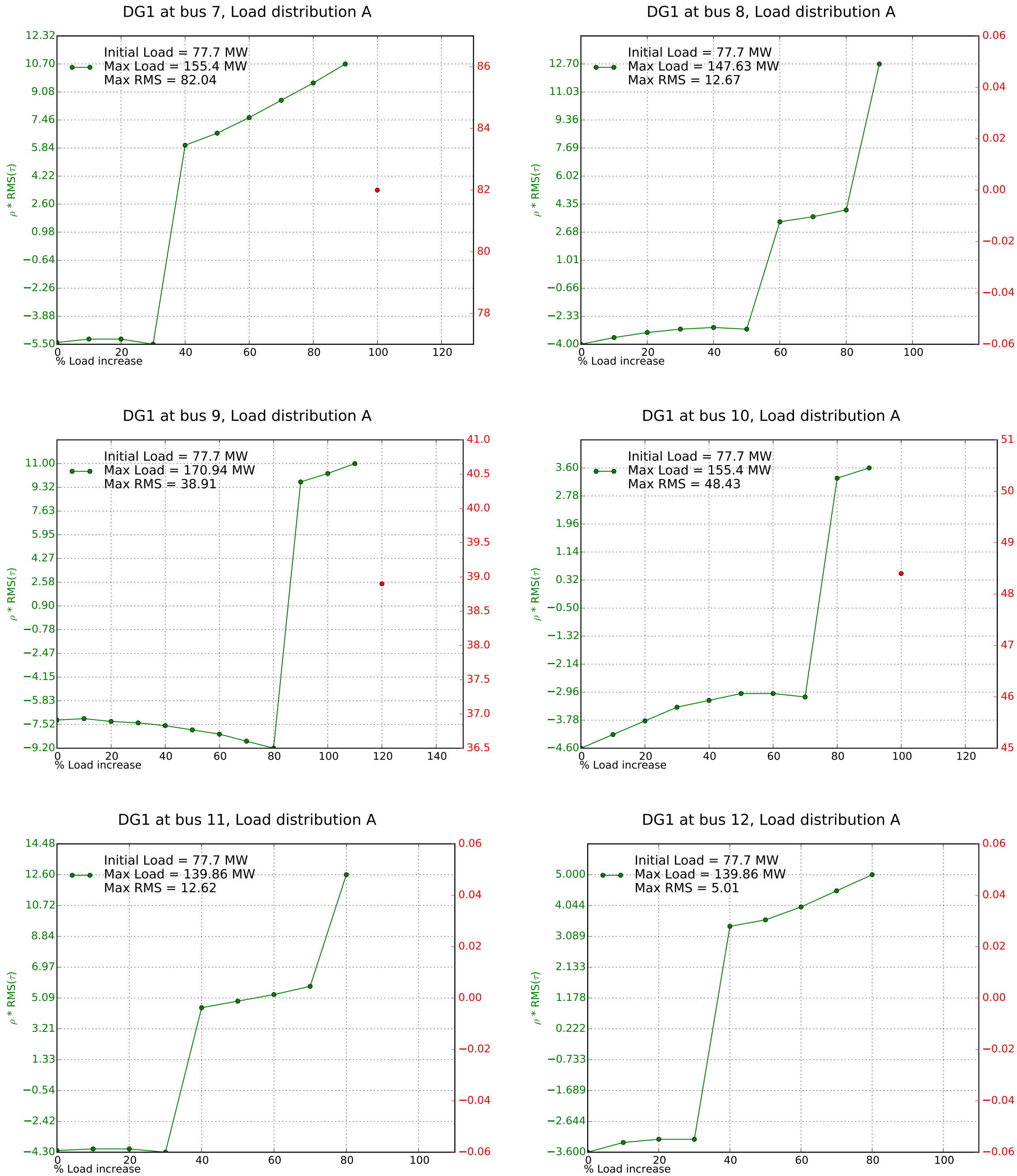


Figure 5.4: DG1 installation results buses 7 through 12, System A

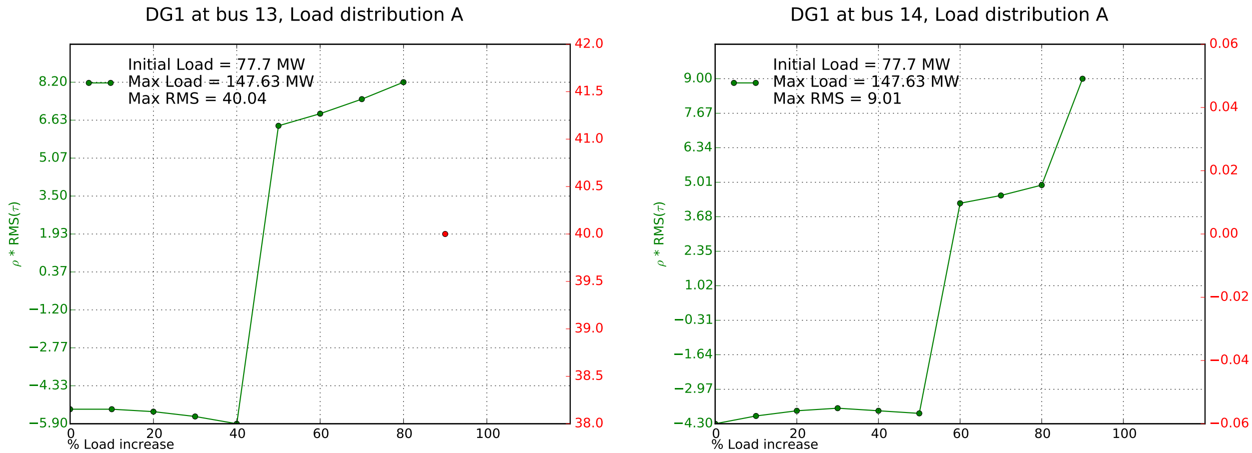


Figure 5.5: DG1 installation results buses 13 and 14, System A

With DG1 at bus 1, we find the $\rho \times$ RMS to be negative, meaning the system is utilizing the cheaper DG1 more than the traditional generators, driving the price down. The load limit is the same as System A without any DG, which is 132.09 MW. The only difference is the effect on LMP. Similar scenarios are found in a few other buses, making the choice for the ideal DG location difficult. It is evident that LMP prices either fall or impede the rise, both important aspects when pushing for deregulation.

At bus 3 the highest load support of 271.95 MW was possible with the help of DG1. Bus no 3 showed the maximum load increase among all the 14 locations. With the positive effects of DG1 at bus 3 and the locations ability to support more load, bus 3 can be an ideal candidate for DG placement in this scenario.

5.2.2 Distributed Generation Utilization

The results before are a direct consequence of the amount of DG1 being utilized in the system. MATPOWER's Optimal Power Flow optimizes the 14 bus system with the added DG1 to minimize the fuel costs, at each load increase. The results below are the DG1 outputs at each bus location to changes in load demand. The rise and fall noticed in these graphs reflects the minimization optimization of the OPF. Locations such as bus 3 welcome DG input with DG1 output reaching 131.68 MW. While bus 8, takes in around 32 MW DG input all throughout, despite load increases and continues to do so until system collapses.

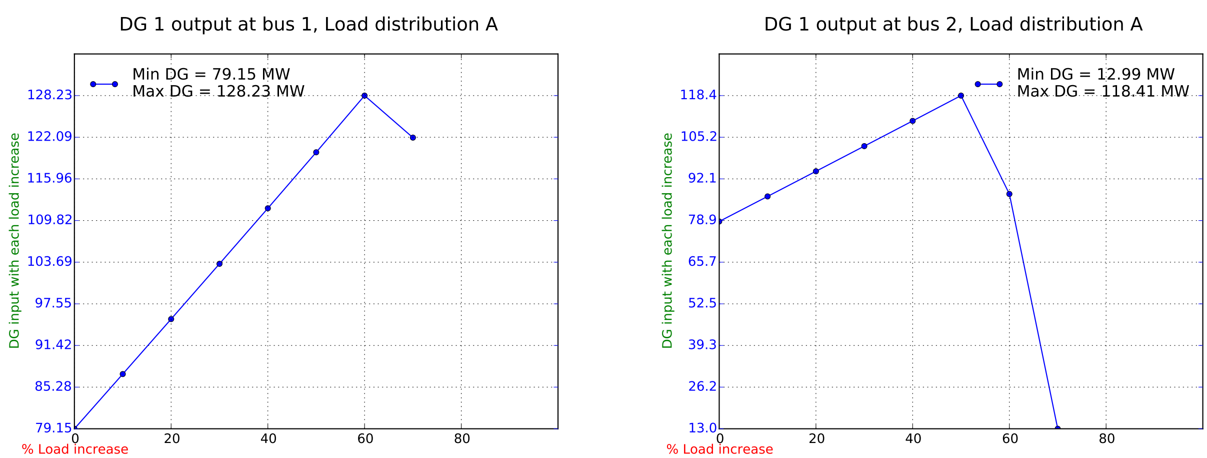


Figure 5.6: DG1 outputs buses 1 and 2, System A

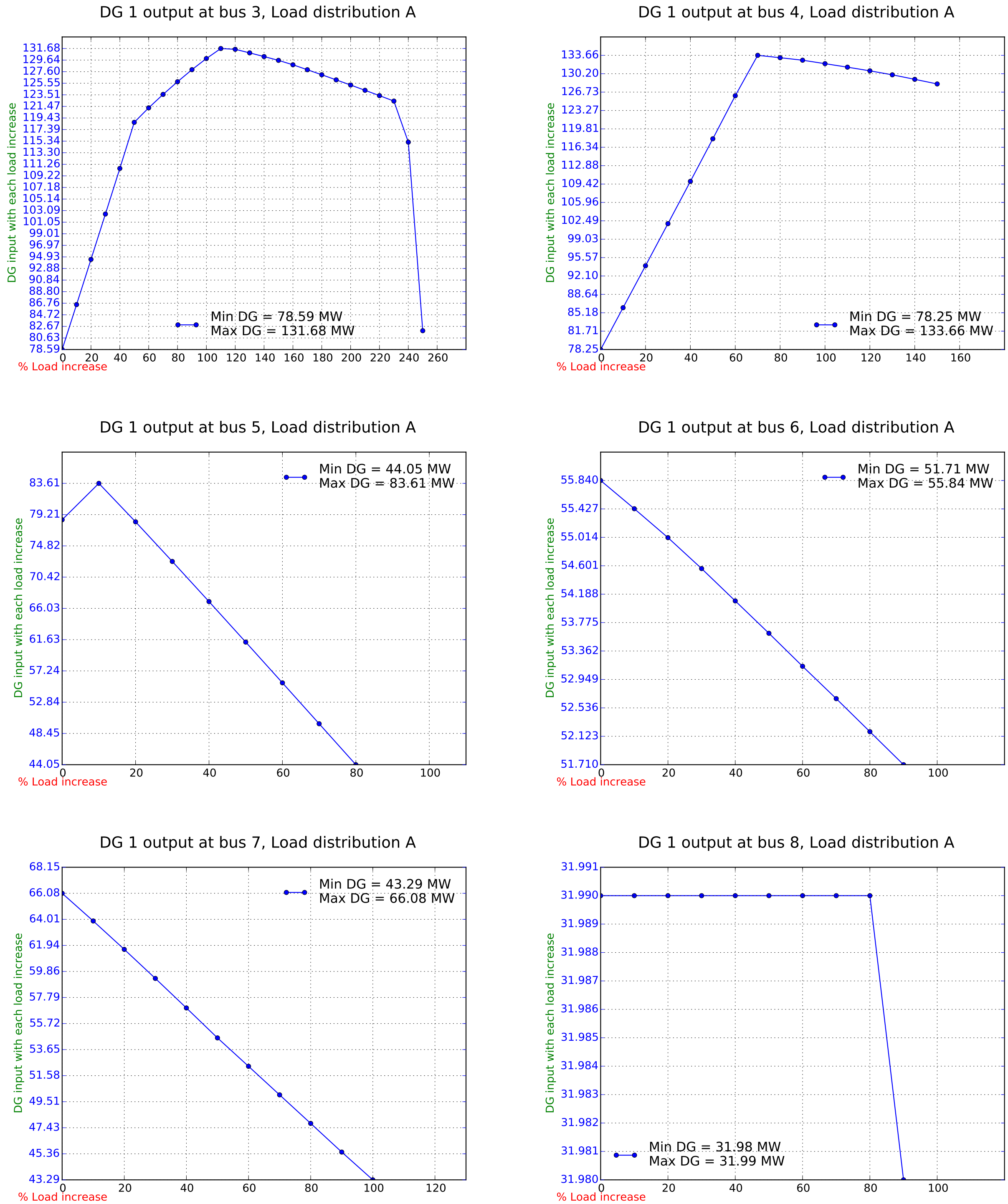


Figure 5.7: DG1 outputs buses 3 through 8, System A

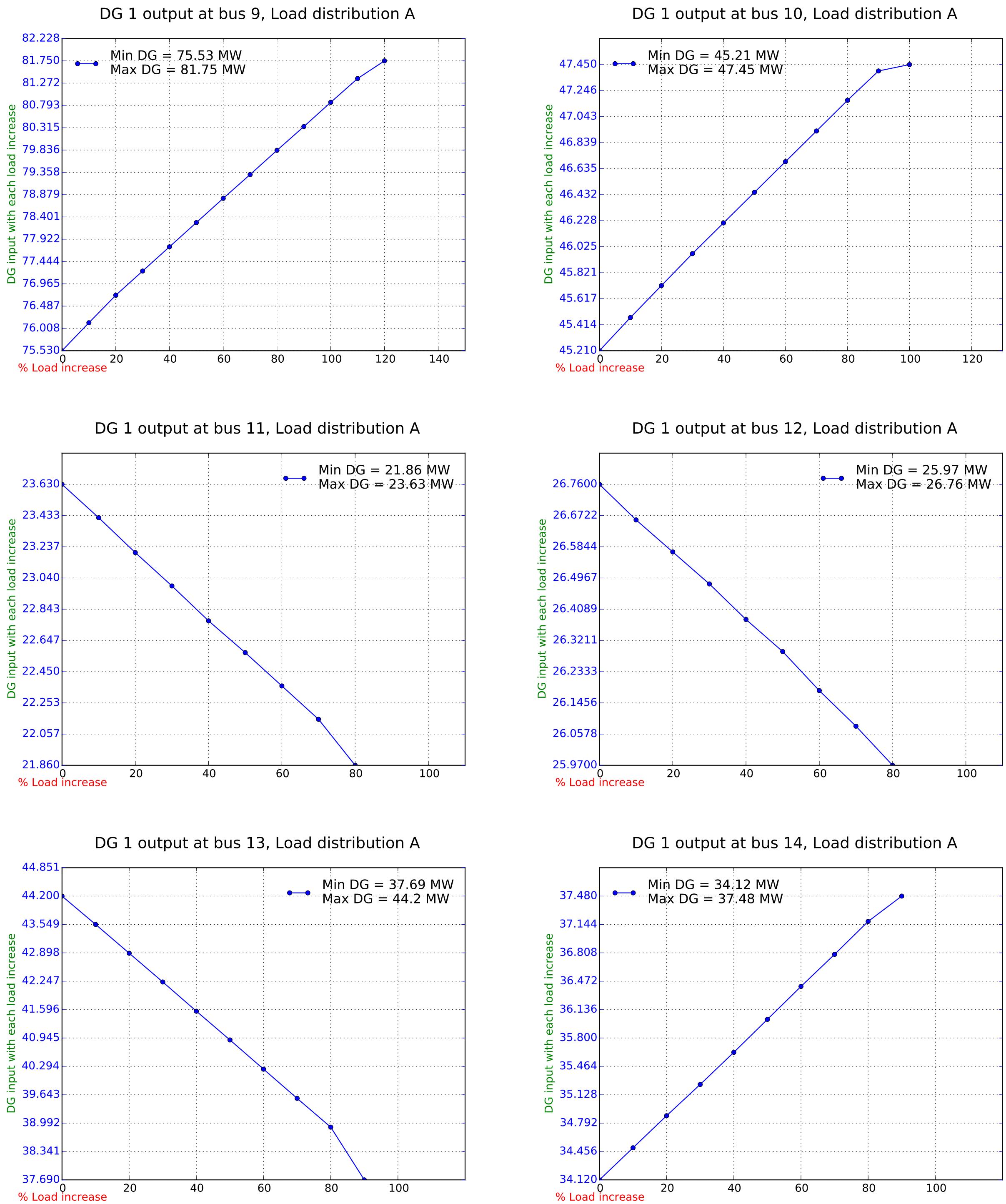


Figure 5.8: DG1 outputs buses 9 through 14, System A

5.2.3 Line Contingency: N-1 and N-2

The N-1 and N-2 contingencies are tested with DG1 placed at each bus location. The load is the same which was tested for system A without DG before (132.09 MW).The results are presented below. The following is the N-1 findings.

DG placement	line contingency passed (20 total)
bus1	12
bus2	12
bus3	**18**
bus4	17
bus5	14
bus6	16
bus7	17
bus8	17
bus9	17
bus10	16
bus11	14
bus12	14
bus13	16
bus14	17

Table 5.1: N-1 contingency with DG1 on system A

And the N-2 results in table 5.2. It is easy to notice that placing DG1 at bus 1 and 2 results the same outcome as the scenario without any DG. The two tables shows that placing DG at bus 3 will pass the maximum number of contingencies. Both these tables confirm that the bus 3 is the ideal location.

DG placement	line contingency passed (190)
bus1	70
bus2	70
bus3	**151**
bus4	134
bus5	94
bus6	116
bus7	126
bus8	125
bus9	139
bus10	121
bus11	91
bus12	96
bus13	112
bus14	126

Table 5.2: N-2 contingency with DG1 on system A

5.2.4 Social Welfare Maximization

[20] based their optimal distributed generation location to be the bus where the social welfare is the maximum. Social Welfare is the summation of the total consumer surplus and producer surplus. Social welfare benefits both consumers and suppliers. Table 5.3 presents the social welfare data and its relation to load increase.

According to the results the maximum social welfare location changes with increase in load. Initially it showed comparable results to [20], where DG1 gave maximum Social Welfare at bus 4. But later the position changes to bus 3. Social Welfare alone cannot decide the position of DG placement.

percentage inc (initial = 77.7MW)	MAX SW BUS	Social - DG1
0	4	6172.48
10	4	6768.14
20	4	7359.72
30	4	7947.13
40	4	8530.28
50	4	9108.66
60	4	9681.96
70	4	10247.81
80	4	10779.18
90	4	11301.40
100	4	11813.59
110	4	12316.25
120	4	12809.27
130	3	13293.70
140	3	13770.67
150	3	14237.93
160	3	14694.53
170	3	15140.48
180	3	15576.26
190	3	16001.77
200	3	16416.90
210	3	16821.54
220	3	17215.58
230	3	17598.89
240	3	17868.77
250	3	15158.02

Table 5.3: Social Welfare with load variation, DG1

5.2.5 Conclusion to Load Distribution A with DG1 installation

From the results it is evident that bus 3 would be the ideal location to install DG1. The benefits are maximization of load (total load of 271.95 MW), impeding locational marginal price rise and passing the maximum N-1 and N-2 contingency situations. The social welfare alone cannot be used to decide the optimal location. But with more proof as presented by the other criterion, it is best to place DG1 at bus 3.

5.3 Load Distribution A with DG2 installation

The steps from Section 5.2 is repeated with a higher costing distributed generator, DG2. The initial load will again be 30 % of the total load of System A (77.7 MW).

5.3.1 Load Variability and LMP tracking

Just like before, the graphs make a distinction between extreme values. The values close to each other are plotted in green. The extremely high values are plotted in red.

The high priced DG2 presents some interesting results. Optimal Power flow prevents the high priced DG2 from generating until absolutely necessary. Results for buses 1 and 2 reflect the same results obtained from system with no DG. Another difference between DG1 and DG2 results is that $\rho \times$ RMS results from DG2 does not include any negative values. Another indication that DG2 is turned on only as a last resort.

Upto 60 % load (132.09 MW) increase, the RMS values across all locations is the same. This is the limit of the system. After the 60 % several DG locations continue to support load increase. The RMS then steadily increases for these locations. Bus 3 comes out on top again, with a maximum load of 271.95 MW. DG2 at bus 3 impedes the rise in LMP the most hence the slow $\rho \times$ RMS value increase. DG2 at other locations, $\rho \times$ RMS increases at a much steeper slope. At each load level, DG at Bus 3 will provide a lower set of LMP value than DGs at other locations.

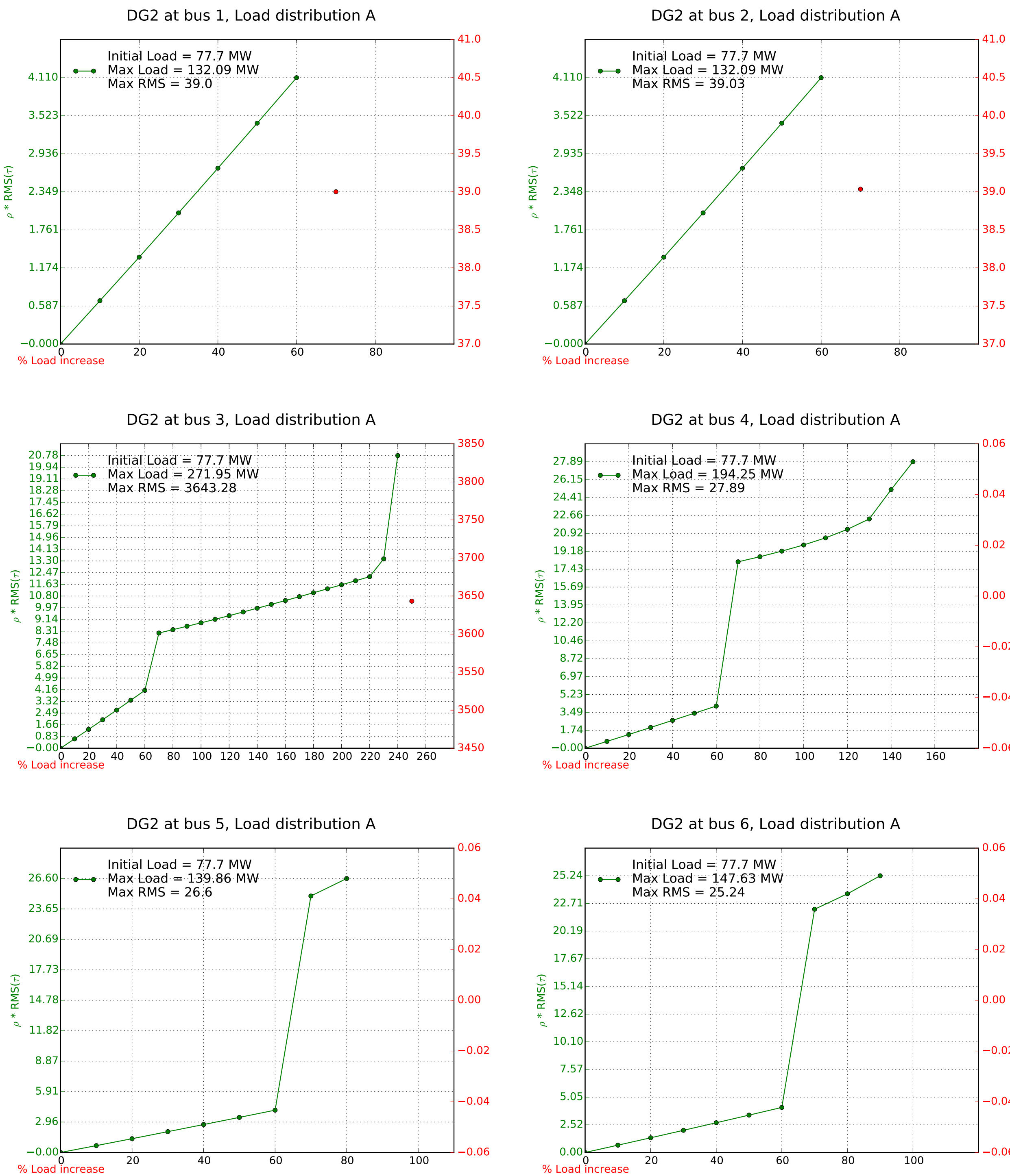


Figure 5.9: DG2 installation results buses 1 through 6, System A

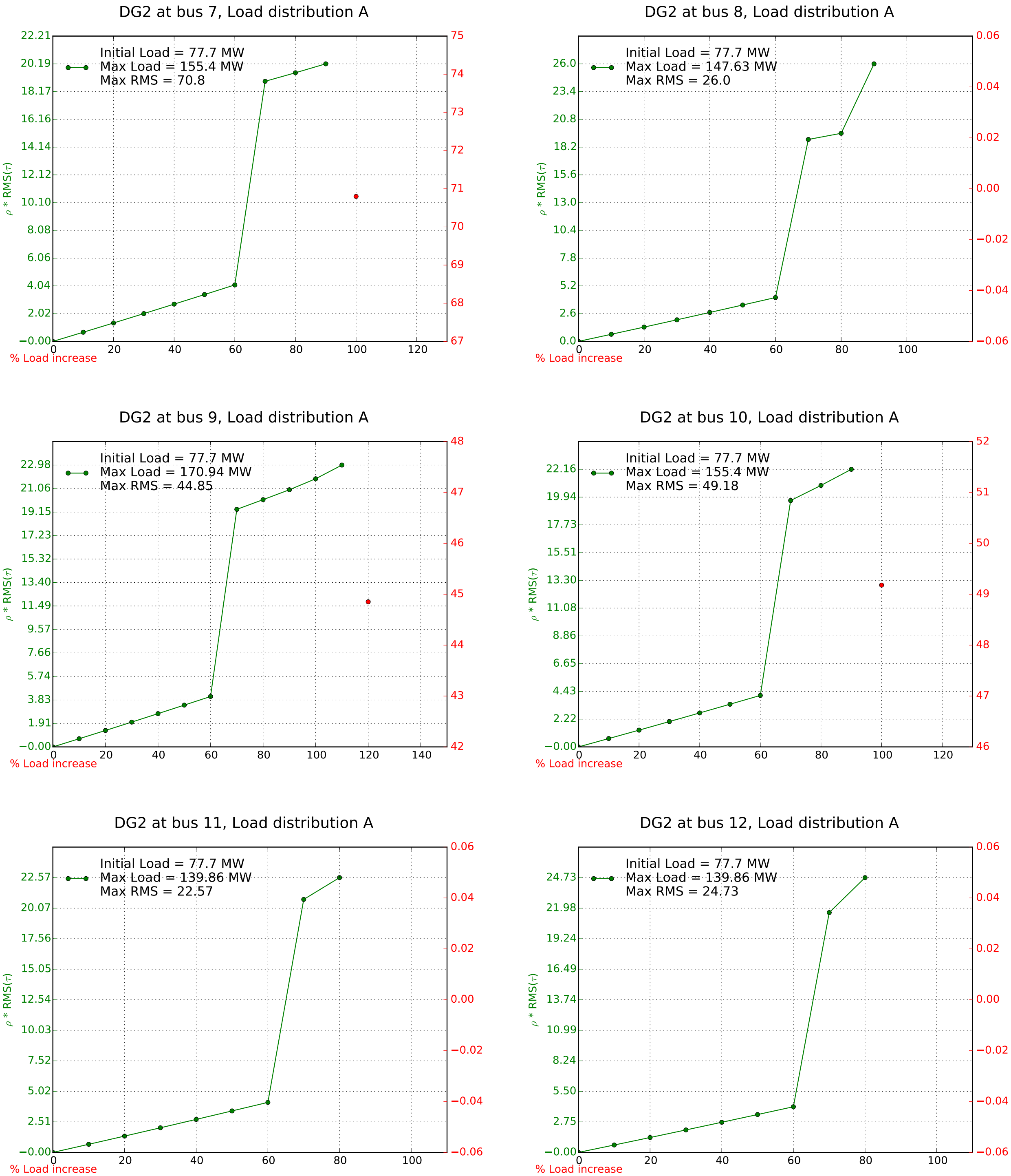


Figure 5.10: DG2 installation results buses 7 through 12, System A

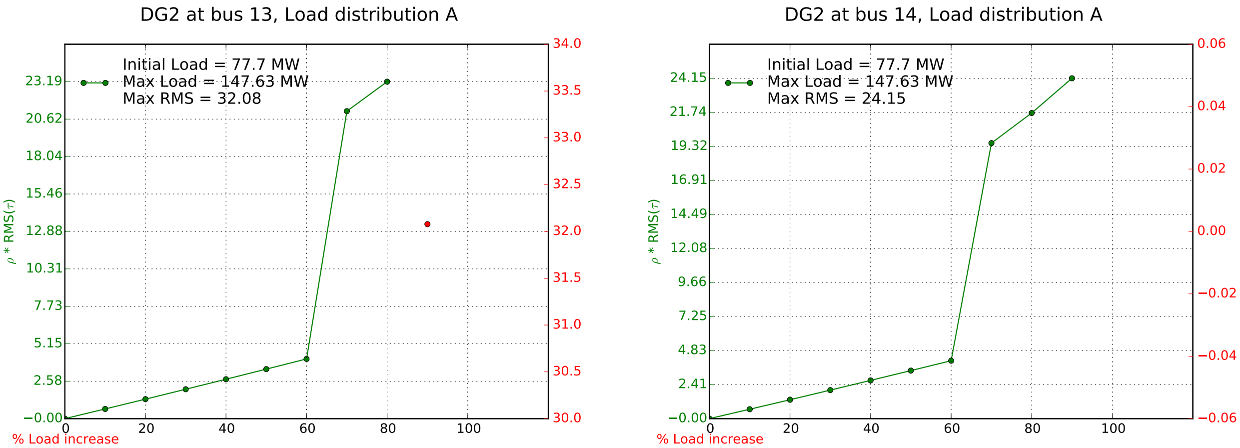


Figure 5.11: DG2 installation results buses 13 and 14, System A

5.3.2 Distributed Generation Utilization

The results in this section correlate to what was said earlier. DG2 being costly does not come into the optimization process unless absolutely necessary by the system. It is not surprising to find DG2 output at bus 1 and 2 be zero. DG2 is much costlier than the traditional generators present at the two buses. In a real world scenario a DG will be connected to the grid at immense load demands. Also much of DG technologies currently in the market such as Solar and Wind are quite expensive. The results of DG2 are much realistic in these sense.

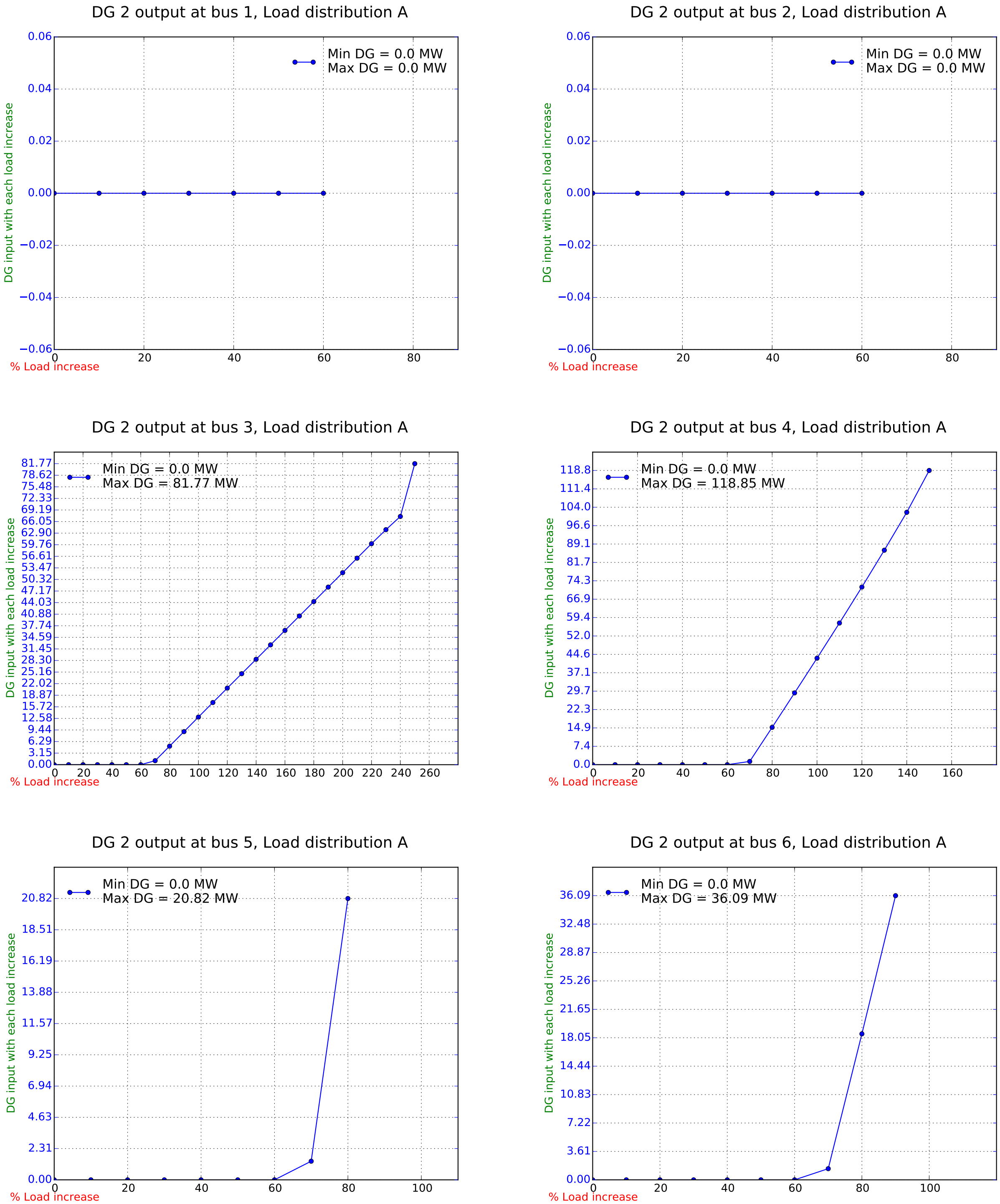


Figure 5.12: DG2 outputs buses 1 through 6, System A

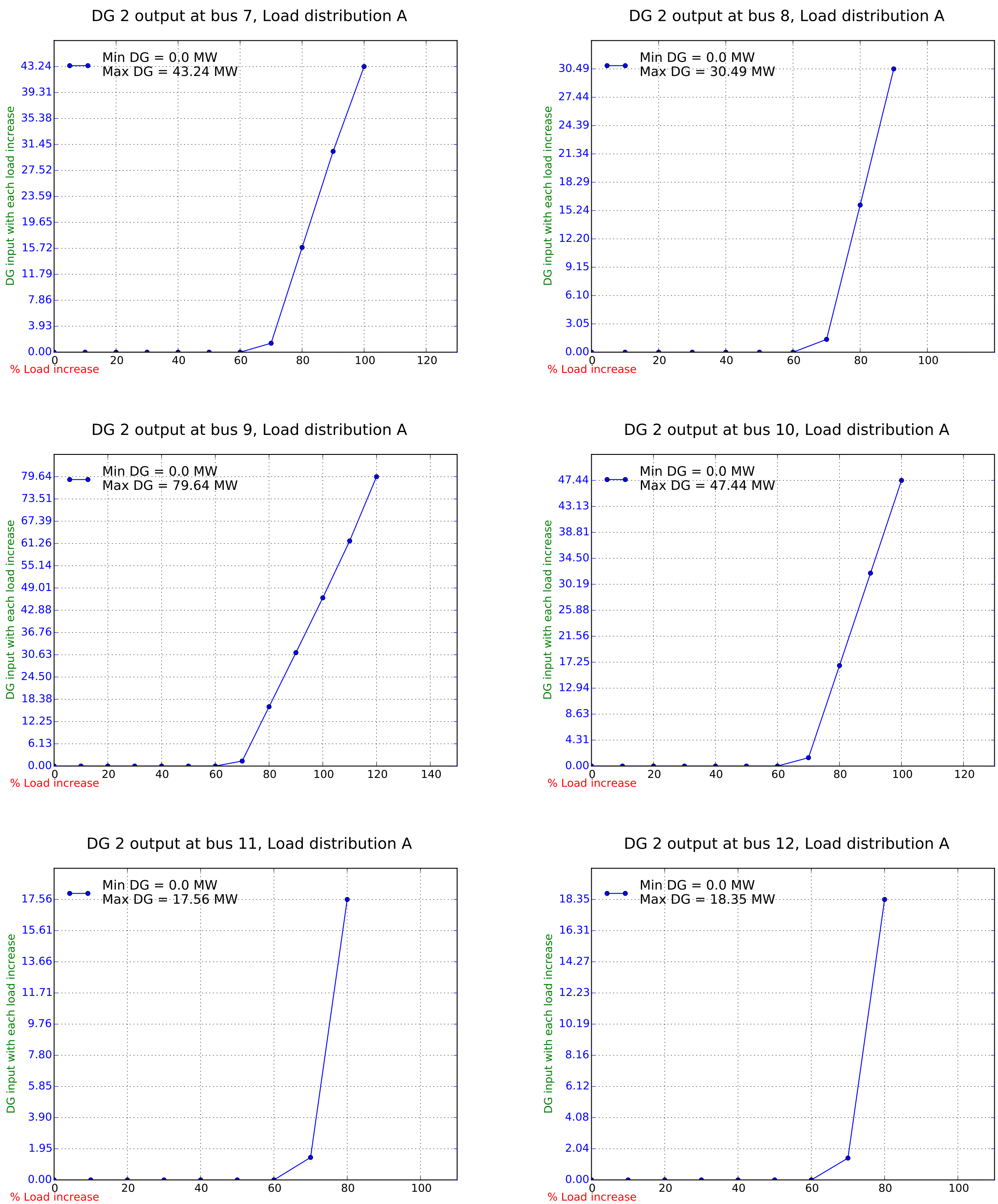
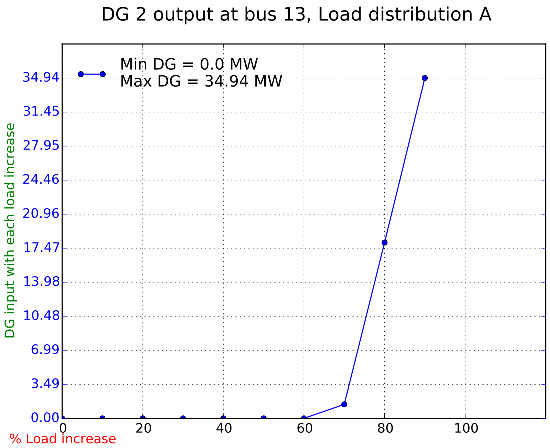


Figure 5.13: DG2 outputs buses 7 through 12, System A



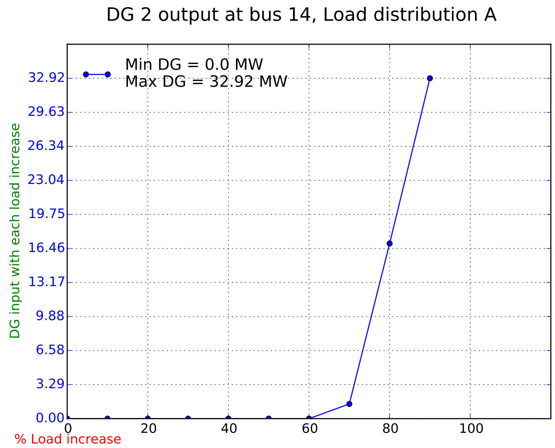


Figure 5.14: DG2 outputs buses 13 and 14, System A

5.3.3 Line Contingency: N-1 and N-2

With load level at 132.09 MW and DG2 installed, the N-1 and N-2 line contingency are tested. Table 5.4 shows the results of the N-1 contingency.

DG placement	line contingency passed (20 total)
bus1	12
bus2	12
bus3	**18**
bus4	17
bus5	14
bus6	16
bus7	17
bus8	17
bus9	17
bus10	16
bus11	14
bus12	14
bus13	16
bus14	17

Table 5.4: N-1 contingency with DG2 on system A

And the N-2 results in table 5.5. It can be quickly remarked that cost of DG is not relevant to the testing of the line contingencies. The exact same results are obtained with the DG2 that was obtained with DG1. Again bus 3 has shown that it will be a good candidate for DG placement.

DG placement	line contingency passed (190)
bus1	70
bus2	70
bus3	**151**
bus4	134
bus5	94
bus6	116
bus7	126
bus8	125
bus9	139
bus10	121
bus11	91
bus12	96
bus13	112
bus14	126

Table 5.5: N-2 contingency with DG2 on system A

5.3.4 Social Welfare Maximization

The discontinuation of maximum social welfare was found yet again. Bus 14 started out as having the max social welfare but eventually bus 3 gains the position of having the maximum. The max social welfare bus location varies with load increments.

percentage inc (initial = 77.7MW)	MAX SW BUS	Social - DG2
0	14	5551.02
10	14	6058.56
20	14	6557.27
30	14	7047.09
40	14	7527.94
50	14	7999.77
60	14	8462.53
70	3	8900.96
80	3	9303.86
90	3	9701.73
100	3	10094.56
110	3	10482.36
120	3	10865.07
130	3	11242.68
140	3	11615.16
150	3	11982.52
160	3	12344.74
170	3	12701.83
180	3	13053.77
190	3	13400.55
200	3	13742.16
210	3	14078.61
220	3	14409.88
230	3	14735.20
240	3	15046.20
250	3	12859.79

Table 5.6: Social Welfare with load variation, DG2

5.3.5 Conclusion to Load Distribution A with DG2 installation

Placing DG2 at bus 3 has increased the maximum load limit of the system. DG2 has helped impede the locational marginal prices at bus 3 more than other locations. And as before it has helped pass the maximum number of N-1 and N-2 contingencies. Whether it be DG1 or DG2, the ideal location for placement has been found to be bus 3.

5.4 Load Distribution B with DG1 installation

System B has a different distribution load, a total of 323.5 MW load. The initial starting load is 30 %, which is 97.05 MW. Increments are made to generate the results that will be discussed next.

5.4.1 Load Variability and LMP tracking

Similar to system one, some of the LMP root mean square achieves a negative value. This is due to DG1, which is a cheaper alternative to the traditional generators in the system. Having access to cheaper generation drives the LMP down across all buses. Also the highest load increase is found at bus 11 (178.71 MW total).

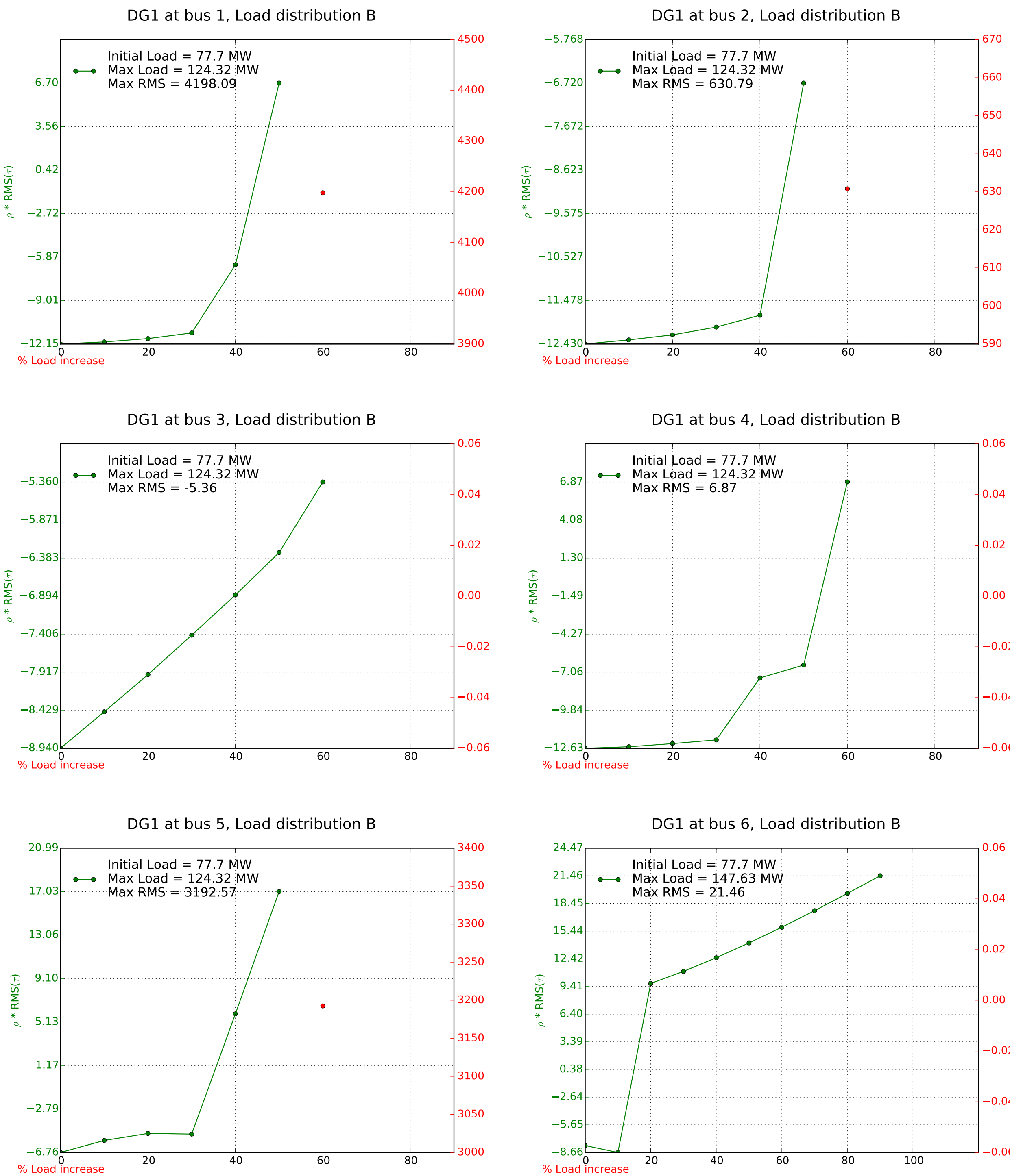


Figure 5.15: DG1 installation results buses 1 through 6, System B

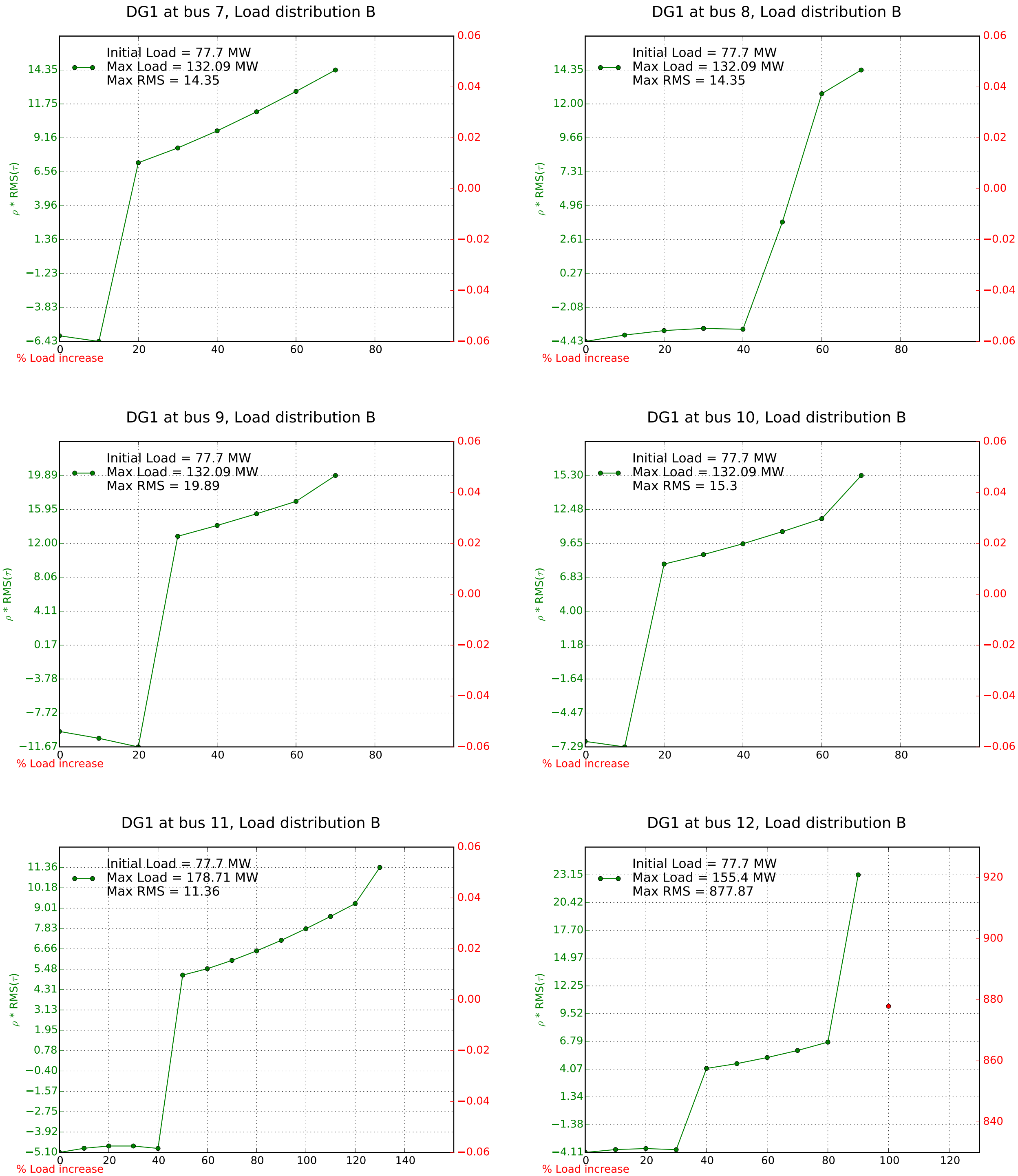


Figure 5.16: DG1 installation results buses 7 through 12, System B

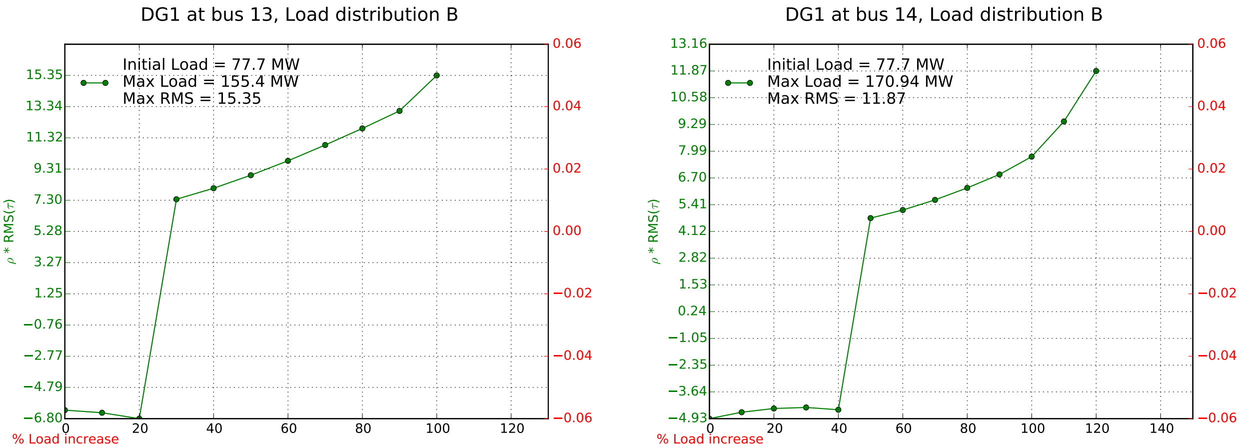


Figure 5.17: DG1 installation results buses 13 and 14, System B

5.4.2 Distributed Generation Utilization

As before we witness the optimization of the Optimal Power Flow, with its ability to optimize price and flow of power. DG1 outputs are adjusted as necessary by the system load. The outputs are reflected in the graphical representation below.

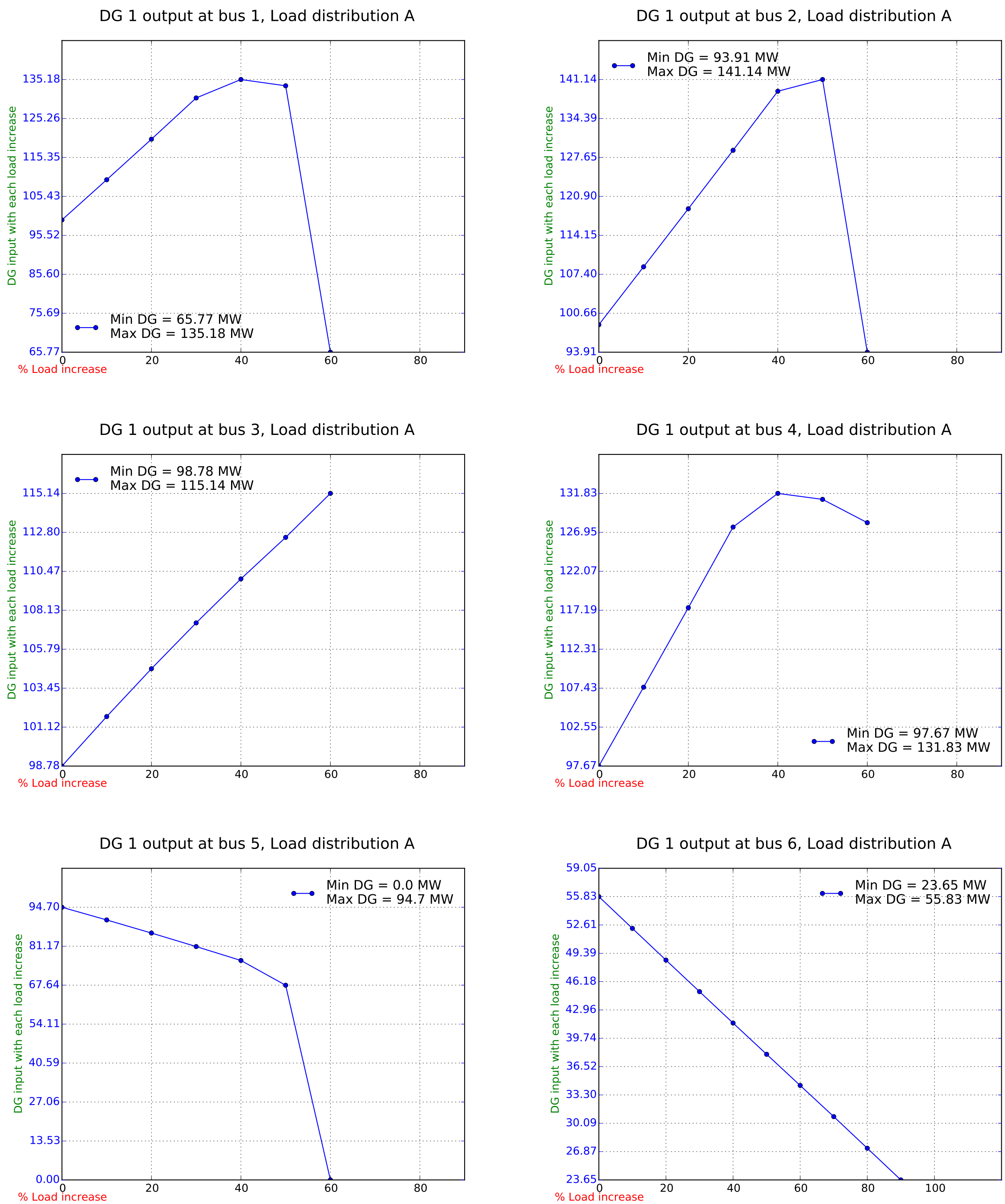


Figure 5.18: DG1 outputs buses 1 through 6, System B

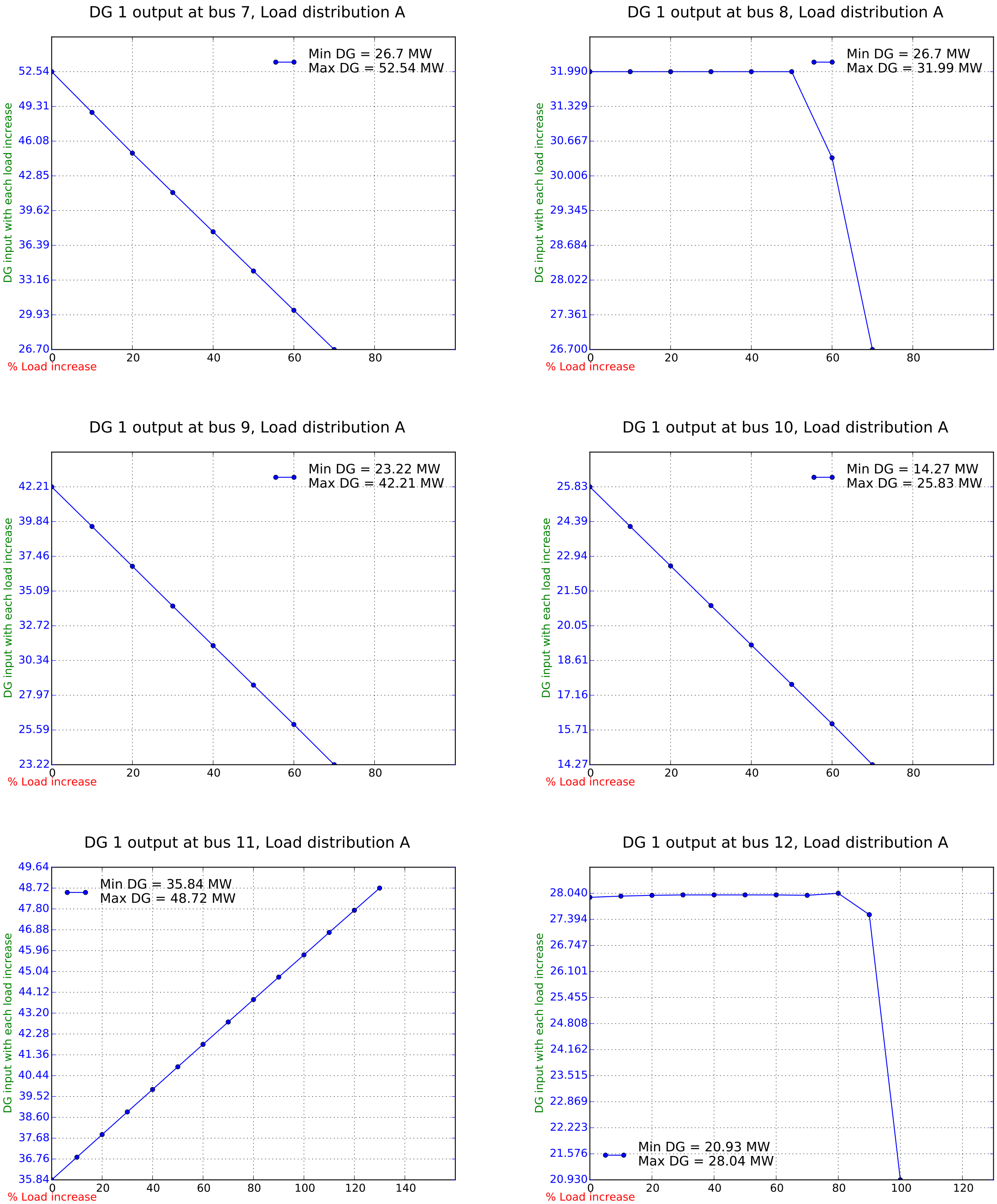


Figure 5.19: DG1 outputs buses 7 through 12, System B

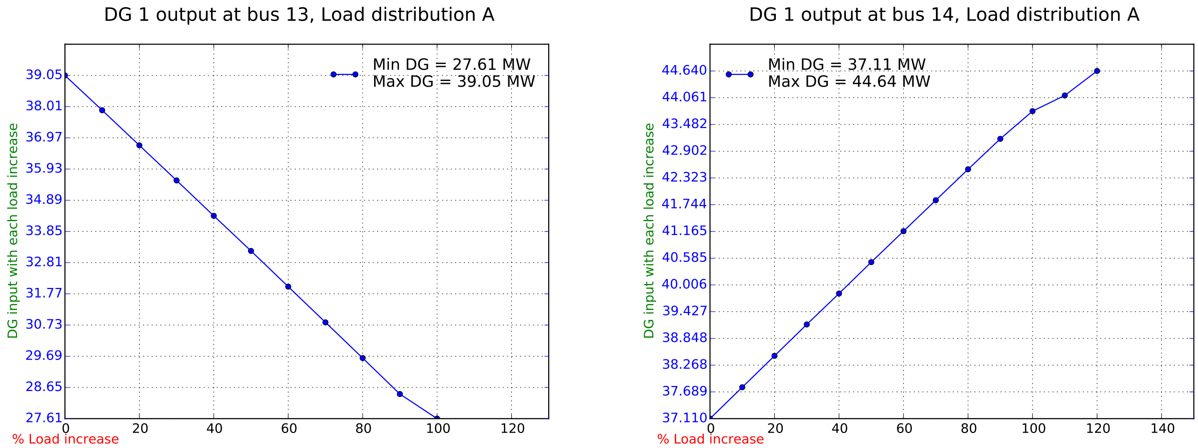


Figure 5.20: DG1 outputs buses 13 and 14, System B

5.4.3 Line Contingency: N-1 and N-2

The load distribution of system B makes it a very critical system, only allowing a maximum load of 178.71 MW at the best DG location. The N-1 and N-2 tests were conducted on a total load of 145.6 MW, the maximum load supported by the system without DG assistance.

DG placement	line contingency passed (20 total)
bus1	7
bus2	7
bus3	10
bus4	10
bus5	8
bus6	12
bus7	11
bus8	11
bus9	13
bus10	14
bus11	**16**
bus12	11
bus13	12
bus14	14

Table 5.7: N-1 contingency with DG1 on system B

DG placement	line contingency passed (190)
bus1	28
bus2	28
bus3	45
bus4	50
bus5	37
bus6	63
bus7	56
bus8	56
bus9	80
bus10	91
bus11	**117**
bus12	54
bus13	64
bus14	90

Table 5.8: N-2 contingency with DG1 on system B

DG1 at Bus 11 passes a maximum 16 out of the 20 N-1 scenarios. The situation becomes much worse in the N-2 scenarios, where DG addition passes 117 out of the 190 cases. But it is a huge improvement from the original system, which could only pass 28 of N-2 line scenarios. The complete results are shown in tables 5.7 and 5.8.

5.4.4 Social Welfare Maximization

The max social welfare location is even more inconsistent in this scenario. The max was first found in bus 4 then 2 then back to 4 and lastly bus 11. Load has an impact where the maximum social welfare will be achieved.

percentage inc (initial = 97.05 MW)	MAX SW BUS	Social - DG2
0	4	7414.77
10	4	8135.83
20	4	8852.24
30	4	9563.2
40	2	10248.78
50	2	10913.88
60	4	11531.15
70	11	11211.12
80	11	11777.29
90	11	12333.19
100	11	12878.73
110	11	13413.83
120	11	13938.4
130	11	14452.03

Table 5.9: Social Welfare with load variation, DG1, System B

5.4.5 Conclusion to Load Distribution B with DG1 installation

From the results obtained from all the various tests, it is evident that bus 11 would be the best location for DG1. Bus 11 checks all the tick marks considering maximizing load limit, impeding LMP rise and passing the most N-1 and N-2 scenarios.

5.5 Load Distribution B with DG2 installation

Repeatition of the tests are conducted for the expensive, DG2 for system B.

5.5.1 Load Variability and LMP tracking

The highest loadbility is found at bus 11 (178.71 MW total). Like earlier tests with DG2 on system A, we find the distributed generator to be utilized only when essential for system to continue functioning.

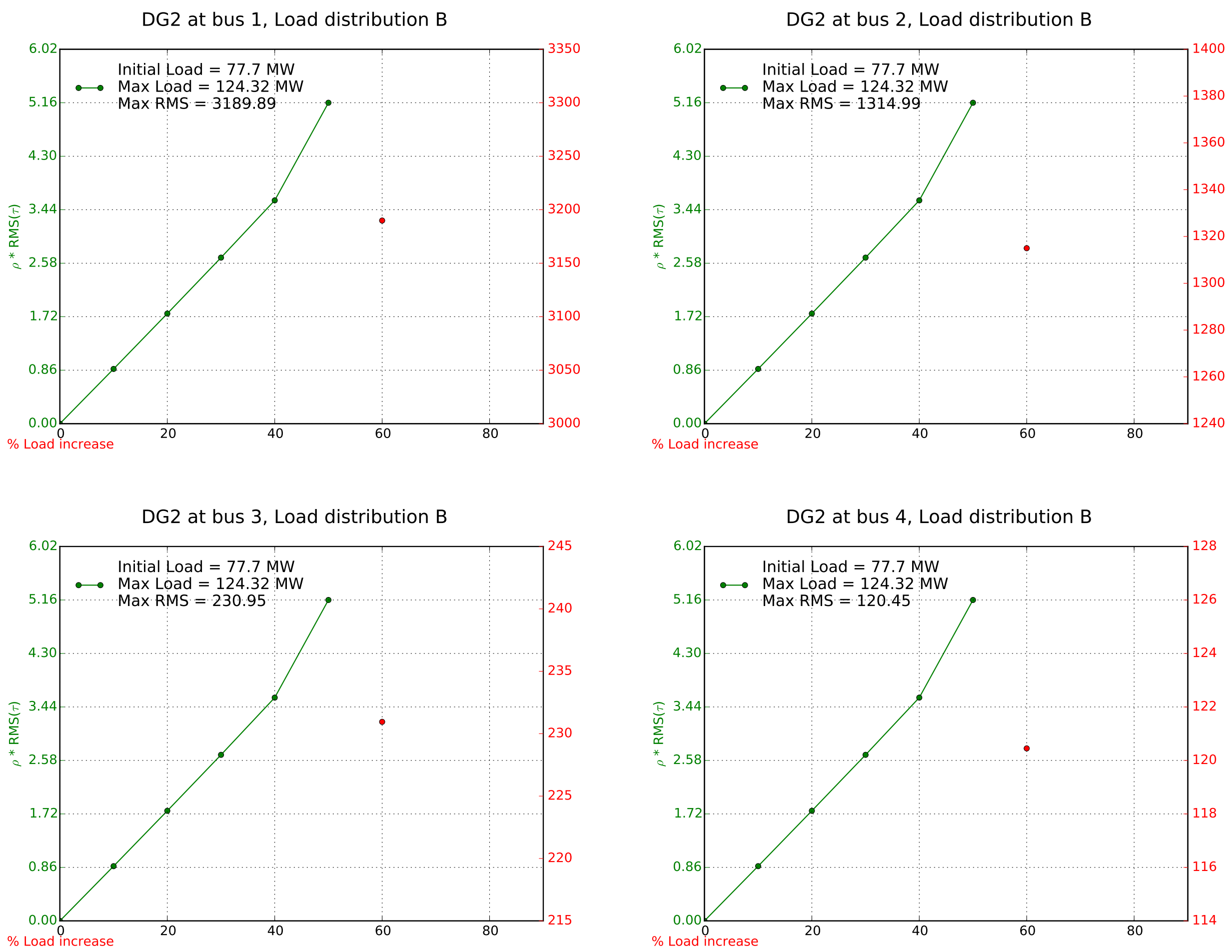


Figure 5.21: DG2 installation results buses 1 through 4, System B

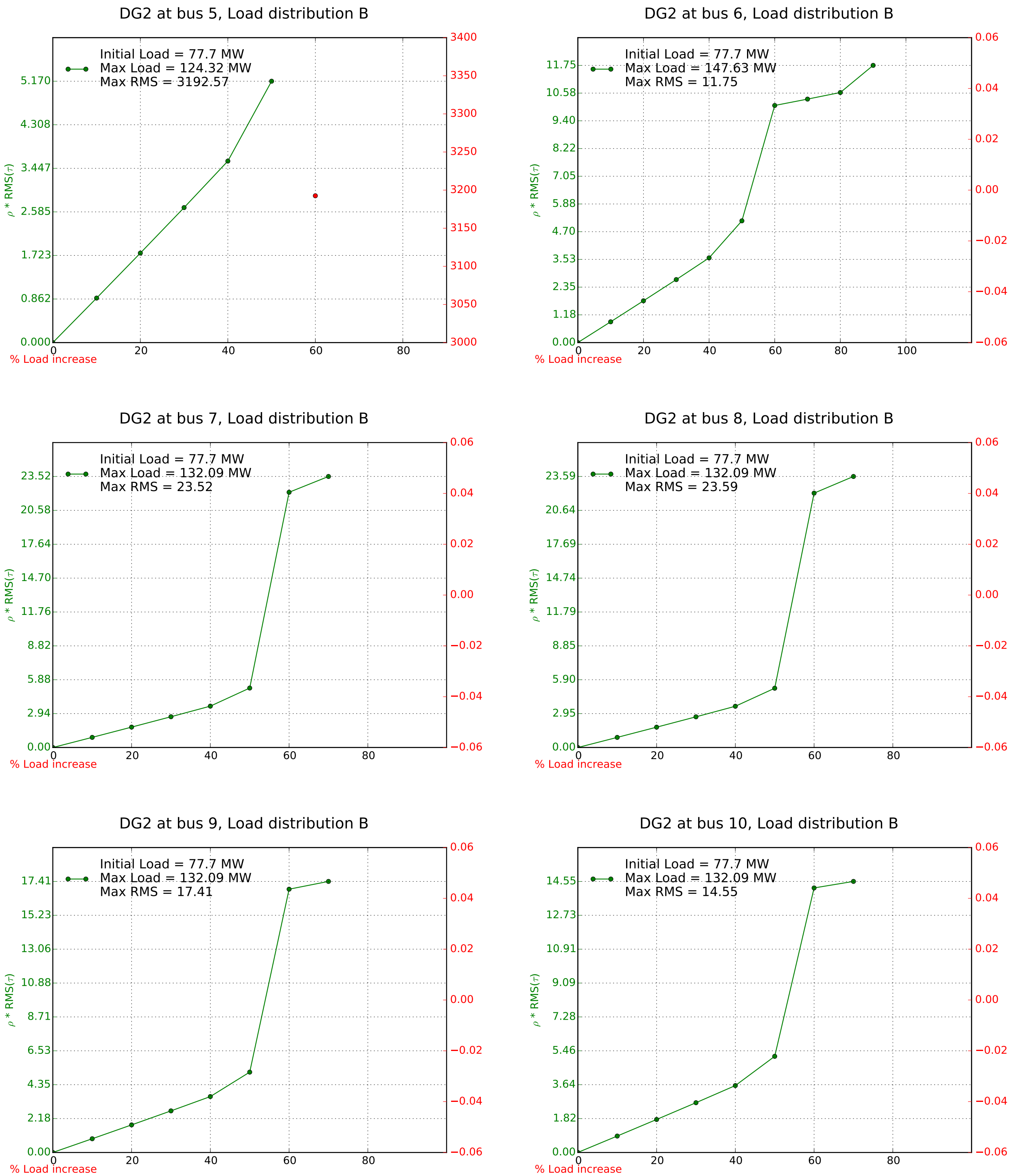


Figure 5.22: DG2 installation results buses 5 through 10, System B

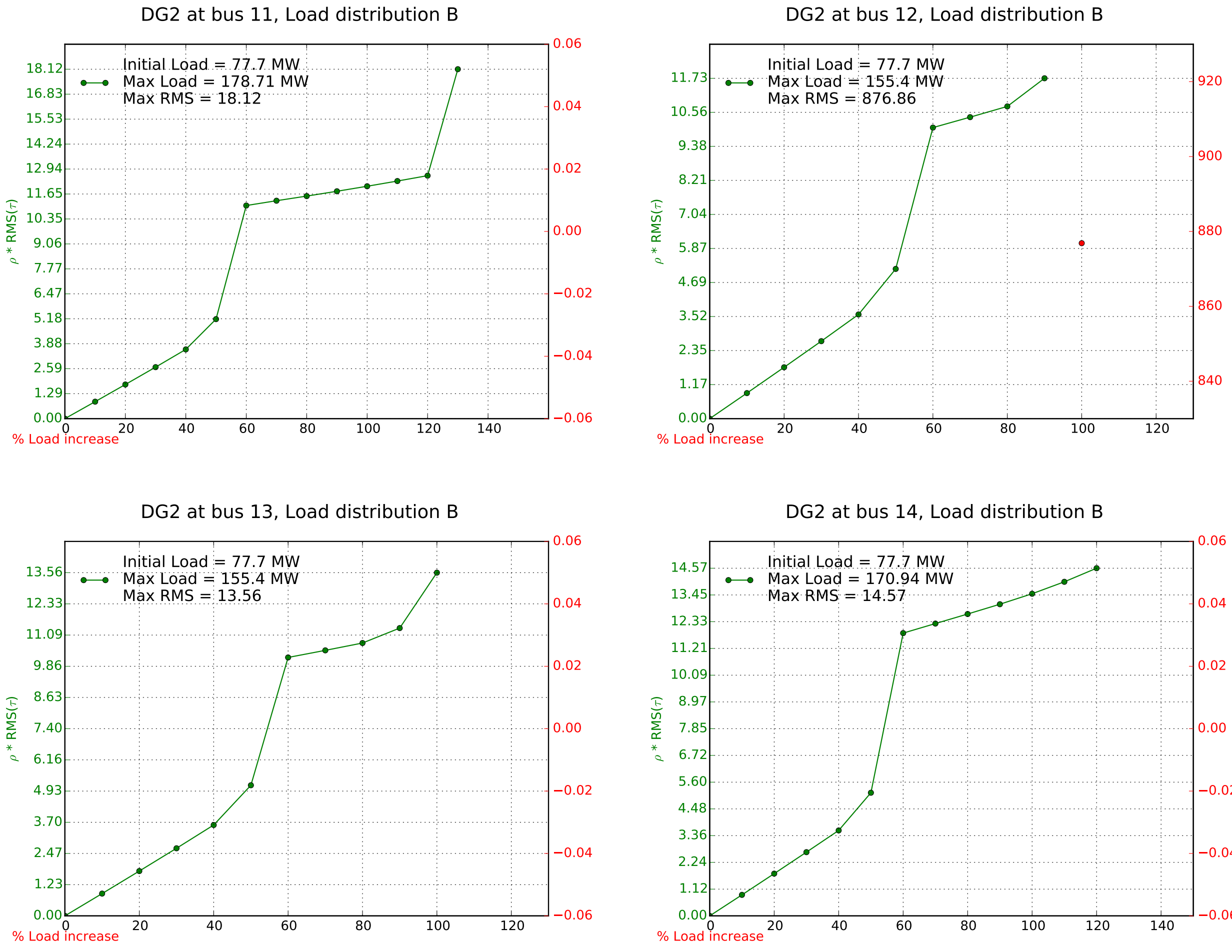


Figure 5.23: DG2 installation results buses 11 through 14, System B

5.5.2 Distributed Generation Utilization

The minimum generation from DG2 is zero. The maximum varies according to location and favorability, bus 11 in this case.

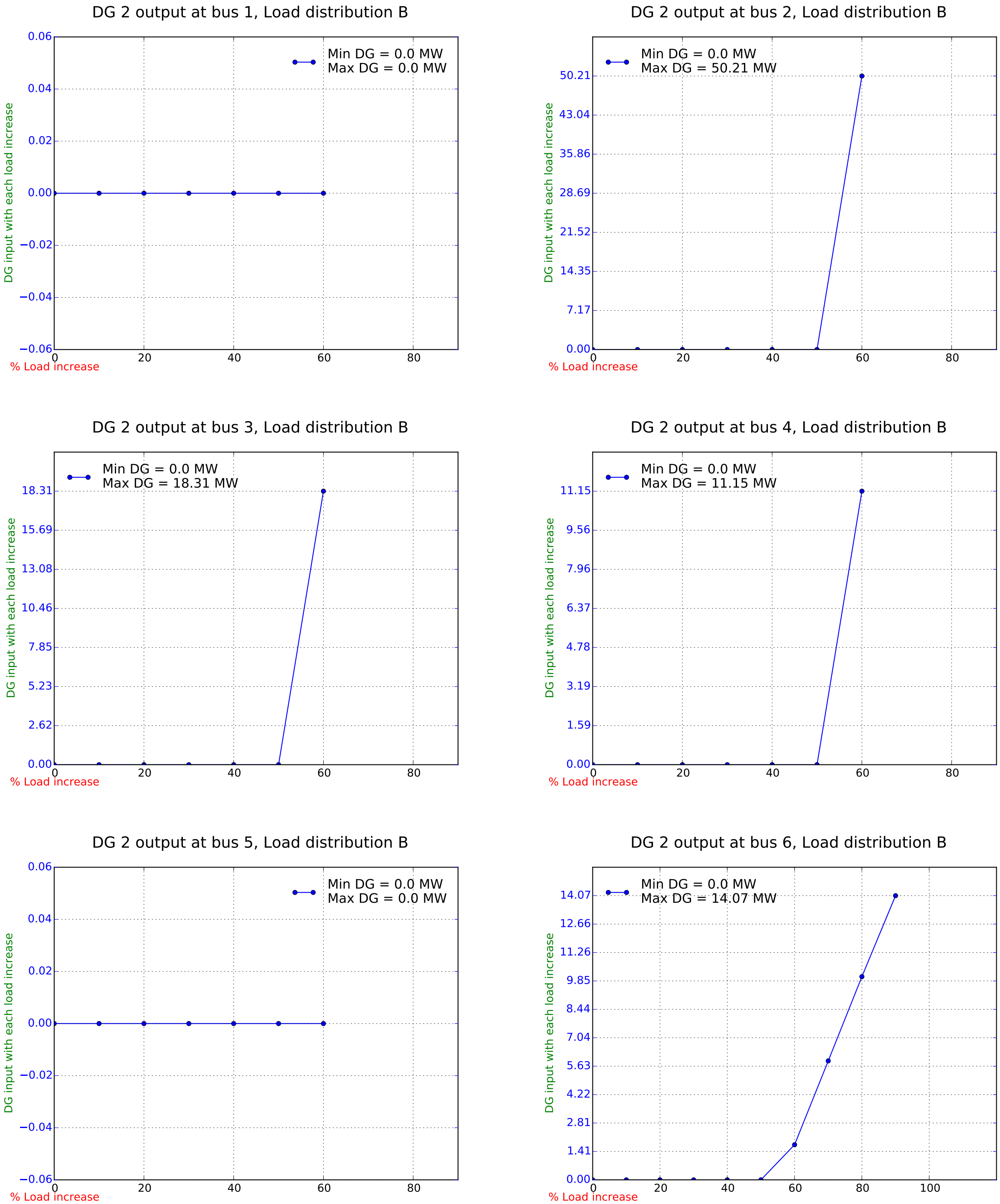


Figure 5.24: DG1 outputs buses 1 through 6, System B

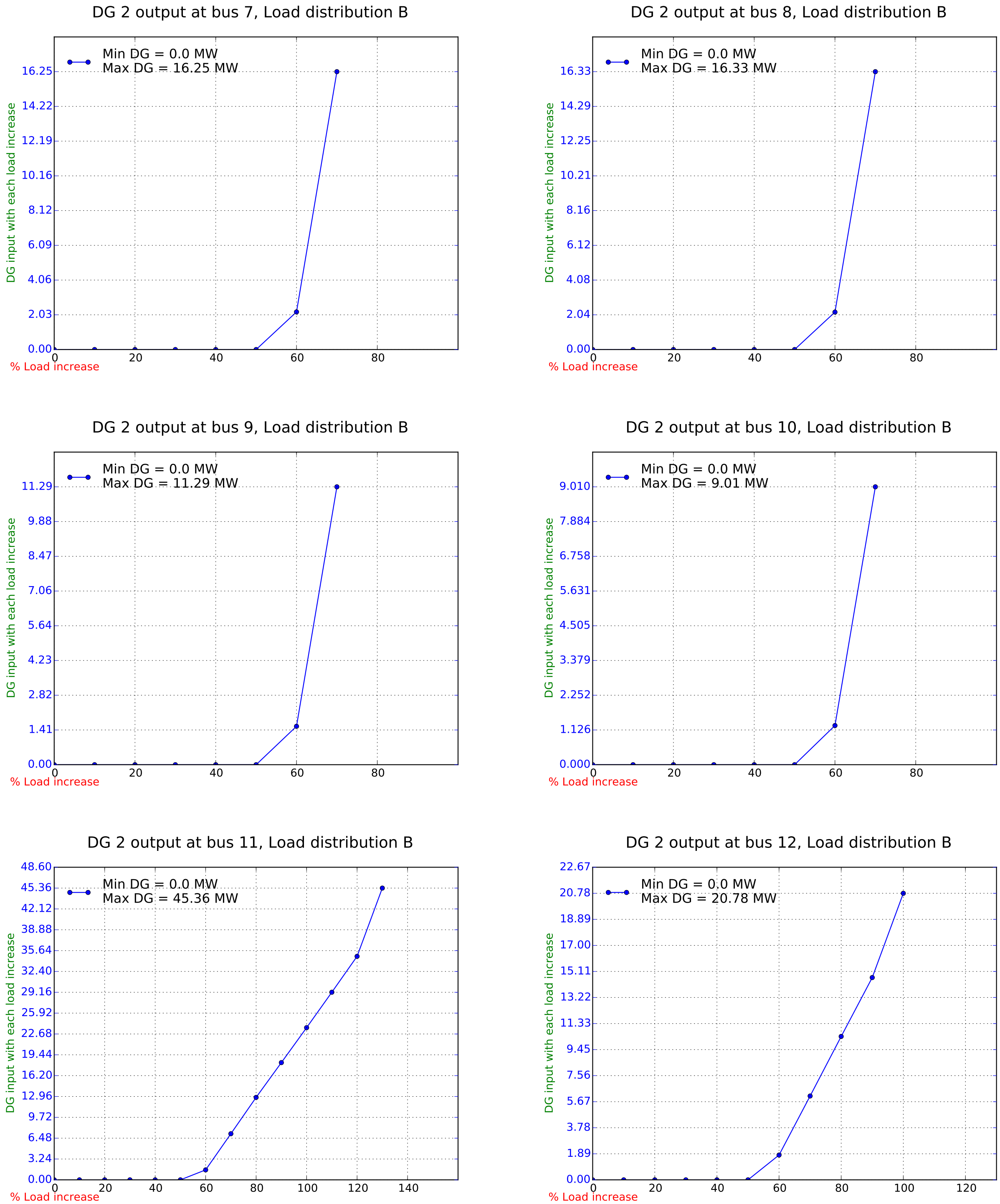


Figure 5.25: DG1 outputs buses 7 through 12, System B

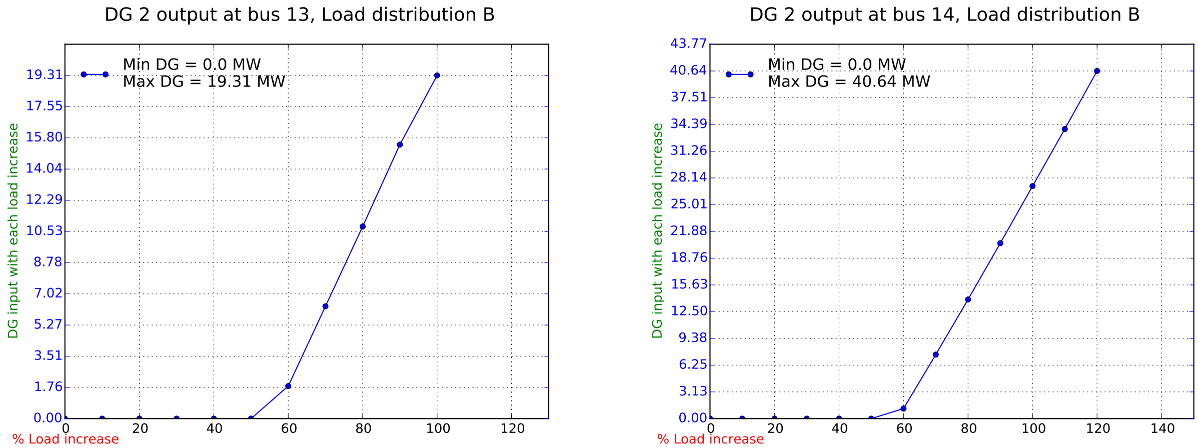


Figure 5.26: DG1 outputs buses 13 and 14, System B

5.5.3 Line Contingency: N-1 and N-2

As previously stated, price of fuel does not affect the line contingency tests. The results are the same we find with the lower costing, DG1.

DG placement	line contingency passed (20 total)
bus1	7
bus2	7
bus3	10
bus4	10
bus5	8
bus6	12
bus7	11
bus8	11
bus9	13
bus10	14
bus11	**16**
bus12	11
bus13	12
bus14	14

Table 5.10: N-1 contingency with DG2 on system B

DG placement	line contingency passed (190)
bus1	28
bus2	28
bus3	45
bus4	50
bus5	37
bus6	63
bus7	56
bus8	56
bus9	80
bus10	91
bus11	**117**
bus12	54
bus13	64
bus14	90

Table 5.11: N-2 contingency with DG2 on system B

5.5.4 Social Welfare Maximization

Lastly we have the comparison of social welfare for load increments. The results from table 5.12 show the inconsistency that arises due to load changes. A proper location for DG cannot be determined this way alone.

percentage inc (initial = 97.05 MW)	MAX SW BUS	Social - DG2
0	14	6556.68
10	14	7150.38
20	14	7732.33
30	14	8302.44
40	14	8860.59
50	14	9405.12
60	12	9915.00
70	6	10401.71
80	6	10882.09
90	6	11353.64
100	13	11808.57
110	11	12250.89
120	11	12700.76
130	11	13104.82

Table 5.12: Social Welfare with load variation, DG2, System B

5.5.5 Conclusion to Load Distribution B with DG2 installation

Bus 11 proves to be the ideal location for DG placement. Maximization of load limit, N-1 and N-2 are unaffected by fuel costs. These tests are enough to determine the ideal location for an additional DG. However, in a deregulated market, where various DG technologies will be present, price is important. It was proven with all the simulations that DG decelerates the LMP rise with load increase. With cheaper DG it is even possible to reduce the LMP even further, resulting in the negative RMS results presented earlier.

Chapter 6

Concluding Remarks and Future Works

6.1 Concluding Remarks

The purpose of this paper was to present an alternative method to locating the optimal placement of a Distributed Generator. With mankind pushing forward to renewable sources of energy, it is quite important to find the best location to install distributed generation. Several Research have been made that emphasize on a single advantage of DG placement. The advantages include but are not limited to improving voltage stabilty or load shed, etc. The objectives in this paper were to improve the maximum load limit, improve line contingency scenarios and reduce the locational marginal price. The optimal DG placement will maximize the demand that the system will be able to handle without system collapse. While doing that, the LMP variation is recorded using $\rho \times \mathrm{RMS}(\tau)$. And finally that location will provide the most security of the system by improving the N-1 and N-2 line contingencies of the system.

In this thesis, the results concluded that a single location for DG was able to account for all of the objectives. The simulations were run on two variants of the IEEE 14 bus system. The two systems vary in their load distribution and thus generate very different results for the conditions that were being set. The two systems, System A and System B had two different optimal locations that ticked off all the objectives. System A's optimal location was found to be bus 3 and System B's to be bus 11.

Having all these advantages benefit both the suppliers and the end users. A system with high demand capabilities would not have to resort to load shed at peak times. A system with improved line contingencies can handle losses of lines during extreme weather conditions, thus improving security to the system. Locational Marginal Price is extensively used in deregulated power markets. The LMP reflects the true price of additional 1 MW of Electricity for that hour at an individual bus locations. In a deregulated market, locations furthest away from generation sites would have to pay more due to increased congestion and power losses due to longer line paths. With the optimal DG placement, the prices across all the buses will be reduced to an acceptable level for the customers. The same location for DG benefits both the utility and the customers.

All of the simulation was run using MATPOWER's Optimal Power Flow tool. The tool developed by PSERC at Cornell University, is easily integrated in MATLAB. The widely used tool is able to solve vast non-linear systems in seconds. The advantage of using OPF is that it generates a realistic system with constraints present in everyday systems. It is very essential to conduct the study in a system that closely resembles the real world systems.

6.2 Future Works

For future work, the proposed metholodies can be simulated while including generator contingencies. A test of how the Distributed Generators will handle a loss of one or more conventional generators. The study can be repeated on a several other IEEE standard systems. The study could be conducted while adding two DGs, one at bus 3 and another at bus 11, while modifying the load distribution. The study could be conducted including emission reduction, which was neglected in the current study as the DGs considered here were dispatchable. Finally, improvements could be made on the algorithm used to make the iterative process faster. A larger system than the IEEE 14 bus system would necessitate a faster and powerful algorithm.

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