CSIRO CLUSTER PROJECT #3

Milestone 5

Optimal Sitting and Dispatch of Distributed generation

A software development and simulation of generation and cost optimised controller

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1.1 Introduction

Modern distribution networks operate with distributed generation of which the wind and PV (Alderfer 2000) can be primary technologies. With the recent developments, they share a considerable amount of loads compared to other Distributed Generation (DG) technologies that may exist in a typical distribution network. The output of some of the renewable power generation technologies including Wind and PV varies throughout the year; however their output can be dispatched with the support of energy storage technologies. The optimum, efficient, and economical operation of renewable and new generation technologies requires the use of smart devices which would enable the smart coordination of DGs. Such an arrangement would reduce the use of fossil fuelled DGs such as diesel units or in other words they may able to operate only when they are economical in the operating cycle.

There are algorithms in the published literature for investigating optimal generating unit combinations however they are mostly confined to single bus systems where the hybrid generation technologies are connected. The optimal planning algorithm requires determining the type of generating technology to use, the machine ratings that will satisfy the demand and to operate the system at minimum cost under constrained operating conditions (Pan, Zong et al. 2009; Inglis, Ault et al. 2010). The literature suggests that there are three main types of algorithms that can be used to solve a planning problem: constructive heuristic algorithms, conventional optimization algorithms and combinatorial algorithms (Romero 1996; Gallego 1998; Lavorato, Rider et al. 2009). Heuristic and conventional optimization algorithms as presented in (Garver 1970), and are used to solve the linear programming (LP) problems associated with the optimisation. The LP algorithm provides a less complex method to formulate the problem and ensures that fast and efficient solutions to the problem with large systems. The LP algorithms consider all the specific characteristics of the problem and they incorporate various constraints associated with the optimal planning of the electrical system and its auxiliaries.

This report presents a software development and a simulation based investigation of optimal sizing of distributed generation units incorporating efficient operation of diesel units. The motivation behind this investigation is to reduce the total cost associated with DG connected power network while reducing the start up cost of diesel units when they are to be operated within the inefficient region of the incremental cost curve. The optimization routine used in this report applies Newton Raphson power flow technique for each sample (Rao, Kumar et al. 2009; Tinney Oct. 1968; D. I. Sun Oct. 1984; Hobson Sept. 1978.) and takes into account the time series simulation, network constraints, and reduction in power losses in determining optimal configuration of DG units at identified locations.

Key findings and implications for the industry

- Modelling investigations suggest that the hybrid DG operation is economical with critical supports from diesels in place of utility grid supply. Wind and diesel hybrid operation can be most economically viable option in generating electricity compared to Wind, PV, and Diesel operation or PV and diesel operation. Wind, PV, and Diesel operation is most economical compared to PV and diesel operation. These arguments are valid if the diesel units are operated in their economical region of operation. The proposed algorithm helps in identifying most beneficial DG mix and capacity for a distribution network.
- Optimal size of DG is dominated by critical events in a power system. These critical events can be contained into weeks or days time frames to determine economically and environmentally viable DG mix and the capacity. Modelling investigations suggest that the demand rise would not affect the critical event made DG mix although the magnitudes of the capacities of DGs are affected. Network planners can use such critical scenario in sizing DG inline with load growth. Identification of critical features is also vital for risk based decisions making.
- According to the performed case studies, the wind and diesel hybrid operation is 13% discounted than wind, PV, and diesel operation. Wind diesel operation is 32% discounted than PV diesel operation. Thus, the wind and diesel hybrid operation provides most economical alternative compared to others in high penetration of DG. This argument is made based on typical and current price components of DG.

Following sections presents the algorithm that framework this part of the project. The algorithm is scripted using PSS/E based ‘IPLAN’ interactive programming language.

1.2 Methodology

Fig. 1.1 shows the methodology used to determine the optimal DG and Diesel plant sizes with an algorithm. For the simplicity of explanation, the algorithm is divided into four sections namely Phase A, Phase B, Phase C, and Phase D. The detailed steps involved in each of the phase are described in the remaining sections.

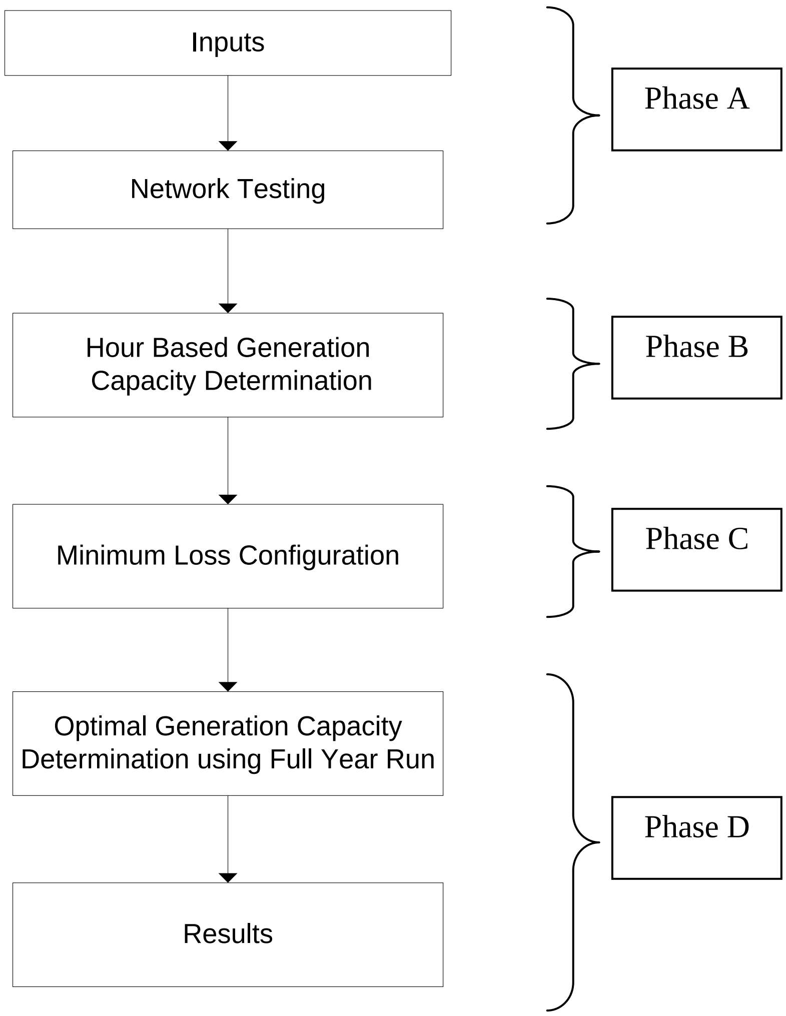


Fig 1.1 Overview of the generation size optimised algorithm

1.2.1 Phase A

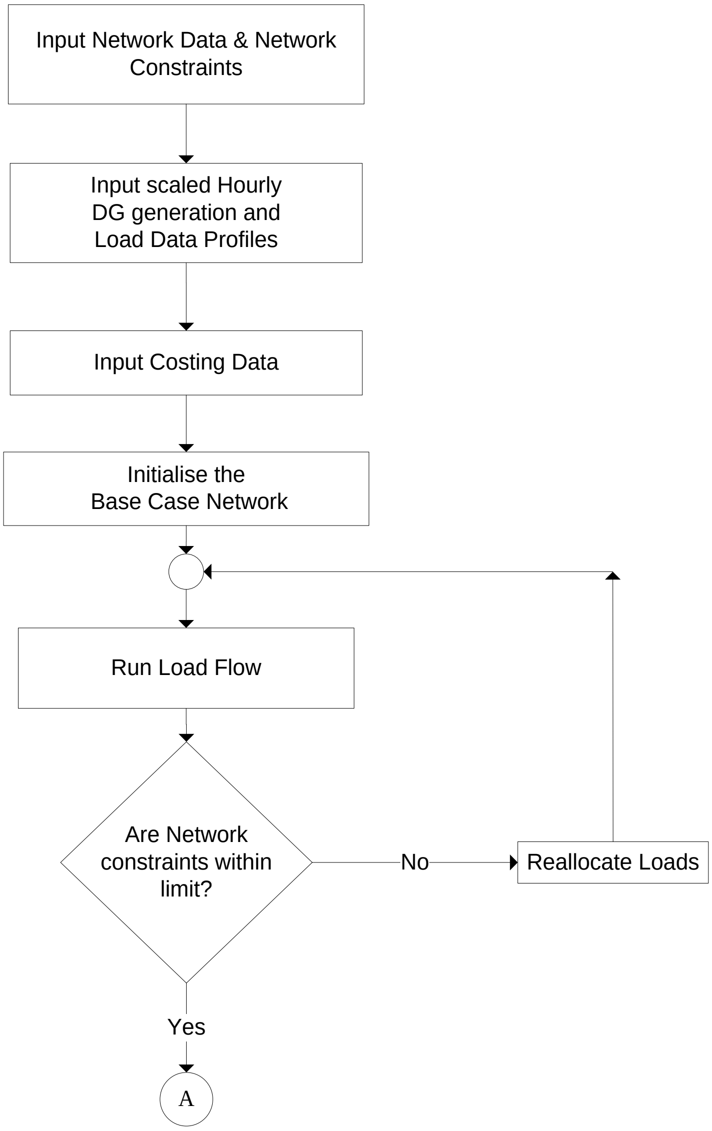


Fig 1.2 Phase A flowchart

Phase A of the algorithm involves data inputs and the verification of the network base case for network constraint violations that include thermal limit of branches violation and voltage limit violations. The network data to be inputted consists mainly of all the network parameters including generator data, load data, feeder and transformer data, bus data, and shunt compensation device data including their locations. The locations, in terms of bus numbers, of the diesel and wind generators and PV systems are required to be provided along with the base case network.

In addition, the distributed generation profiles for the area, that depends mainly on the wind and solar irradiation profiles of the area, are to be given as inputs to the algorithm. The load profile for various types of loads including commercial, industrial, residential have to be inputted into model realistic loading levels at each node.

Upon entering the data, the network feasibility is checked by applying the Newton-Raphson algorithm. Among the load flow algorithms, the Newton-Raphson algorithm requires lesser number of iterations to achieve convergence while providing a complete solution. If the network converges for the operating condition without violating any constraints the operating state is deemed feasible. If it fails to converge or violate constraints, the simulation is temporarily terminated for the sample hour that is active. Then, the generation is re-dispatched using the identified combination until achieving a feasible solution for the hour. On successful convergence of the network, the program proceeds to Phase B of the algorithm.

1.2.2 Phase B

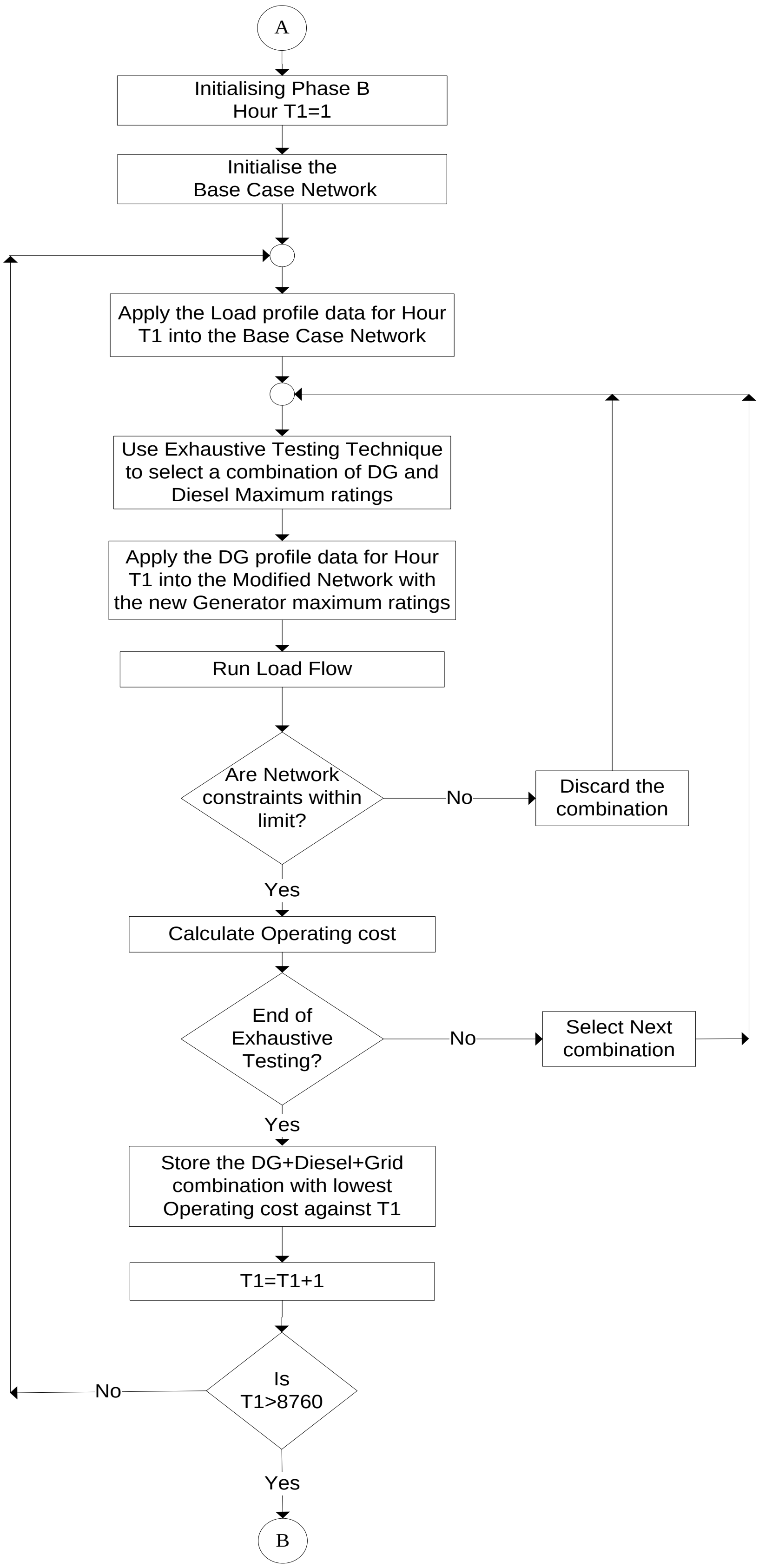


Fig 1.3 Phase B of the flowchart

After the Phase A of the algorithm is successfully executed, the Phase B is processed. In phase B, the most economical combination of generation ratings of all the DGs and diesel generators that best match the load and DG generation profile, for each hour of the year is determined. In Fig. 1.3, the variable T_1 denotes the hour, with the full year having a sum of 8760 hours in total. For each hour, the base case network is restored initially, and the load profiles are applied to base network to get the load for that hour. Treating this load as the reference, various combinations of the DGs and diesel generator ratings are analysed for the network operating condition using exhaustive testing technique. The viability of exhaustive technique for the problem addresses in this report is detailed in section 1.6.1.

Exhaustive testing is a programming technique in which a program is executed with all possible combinations of inputs or values possible for the variables associated with the program (Kevin Sullivan July 2004). In phase B, exhaustive technique is used to analyse the network with all possible combinations of Diesel, Wind and Photovoltaic generator ratings with the maximum being determined by the load associated with network for the Hour T_1. The interval or steps in which the magnitude of the generators are to be varied can be set as an input, thus enabling a controlled testing scenario. The exhaustive testing technique also helps in reducing the actual run time required for executing such an algorithm, since it is an automated form of testing and does not require manual inputs for the ratings that are to be tested.

$$\left(a_1 P_{x_1} + a_2 P_{x_2} + \cdots\right) + \left(b_1 P_{y_1} + b_2 P_{y_2} + \cdots\right) + \left(c_1 P_{z_1} + c_2 P_{z_2} + \cdots\right) + P_{grid}$$

$$\sum_{i=1}^{n_1} a_k P_{x_i} + \sum_{i=1}^{n_2} b_k P_{y_i} + \sum_{i=1}^{n_3} c_k P_{z_i} + P_{grid} = \sum_{i=1}^{n_4} l_k P_{load_i} + P_{loss} \qquad (2)$$

Equation (1) denotes the power balance condition associated with the given power system which has been expressed in Equation (2). P_{x_i}, P_{y_i}, P_{z_i} denote the machine maximum power ratings of the i^{th} diesel generator, wind turbine and photovoltaic system present in the network along with the power supplied by the external grid P_{grid}, in order to meet the load during the k^{th} hour ($l_k P_{load_i}$). The multiplication factors b_k and c_k are taken from the wind and PV generation profile data and along with the P_{y_i} and P_{z_i} gives the actual power produced. The diesel multiplication factor a_k represents the efficiency of the diesel generator associated with its varying percentage loading. Factor l_k is the load multiplication factor inserted from the load profile corresponding to the k^{th} hour. The number of diesel, wind and PV systems present in the network is denoted by n_1, n_2 and n_3. P_{loss} is the overall loss associated with the network or the system power losses.

In Phase B, the exhaustive testing method varies the values of P_{x_i}, P_{y_i}, P_{z_i} such that they satisfy Equation (2) with all possible combinations of diesel, wind and PV ratings. Each of these combinations are then inserted into the base case network and the Newton-Raphson power flow analysis is performed to verify if the combination satisfies all the constraints. The network constraints of voltage upper and lower limits, as well as the thermal overload limit of the network should be within the specified threshold limit. If any of the constraints are violated, then the generating unit combination is discarded and the program carries on to the next generating unit combination for the same hour, until all the possible combinations are being tried out. If it satisfies all the constraints, then the combination is saved and the operating costs associated with it is calculated and stored against the combination.

The operating and maintenance cost ($C_{OM_{x_k}}$) for diesel generator during the k^{th} hour is calculated as in Equation (3)

$$C_{OM_{x_k}} = \left(f_c \times M_k + f_{m_x} \times \sum_{i=1}^{n_1} (a_k P_{x_i}) \right) \quad (3)$$

$$M_k = p + q \times \sum_{i=1}^{n_1} a_k P_{x_i} + r \times \sum_{i=1}^{n_1} \left(a_k P_{x_i} \right)^2 \quad (4)$$

Where f_C is the cost of fuel and f_{m_x} is the maintenance cost per unit production, M_k is mass flow rate of the fuel input which depends on the power output of the diesel generators as shown in Equation (4). The constants p, q and r are coefficients of the generator and are assumed to be the same for all the considered units to simplify the calculations. These constants mainly depend on the make and ratings of the units. Since the algorithm focuses on cost based computation of maximum ratings of the units, proposed unit ratings vary throughout the simulation. These coefficients of generators are assumed constants due to the marginal variations with unit ratings and marginal effects on total cost of operation.

The operating and maintenance cost for wind turbines ($C_{OM_{y_k}}$) and PV system ($C_{OM\_z\_k}$) is calculated using Equations (5) and (6).

$$C_{OM_{y_k}} = f_{m_y} \times \sum_{i=1}^{n_2} b_k P_{y_i} \quad \textbf{(5)}$$

$$C_{OM_{z_k}} = f_{m_z} \times \sum_{i=1}^{n_3} c_k P_{z_i} \quad \textbf{(6)}$$

Where f_{m_y} is the cost of maintenance per unit production for wind turbines and f_{m_z} is the maintenance cost per unit rating of the PV system. These factors take into account the operational costs associated with the respective generation technology and the maintenance costs. Along with these costs, the cost of power supplied by the external grid also has to be taken into consideration. The grid supply cost is calculated as,

$$C_{grid} = f_{grid} \times P_{grid} \quad (7)$$

The total operating or running cost of the whole network is thus expressed as,

$$C_{OM_{total_k}} = C_{OM_{x_k}} + C_{OM_{y_k}} + C_{OM_{z_k}} + C_{grid} \quad \textbf{(8)}$$

When the exhaustive testing comes to an end for hour T_1, all the possible combinations are tried out, and the combination with the least operational cost, is stored against the hour T_1. This way, the process is repeated for the full year (8760 hours) and thus provides 8760 possible combinations of generator ratings for the operating conditions of the network for a year when the time interval is one hour.

1.2.3 Phase C

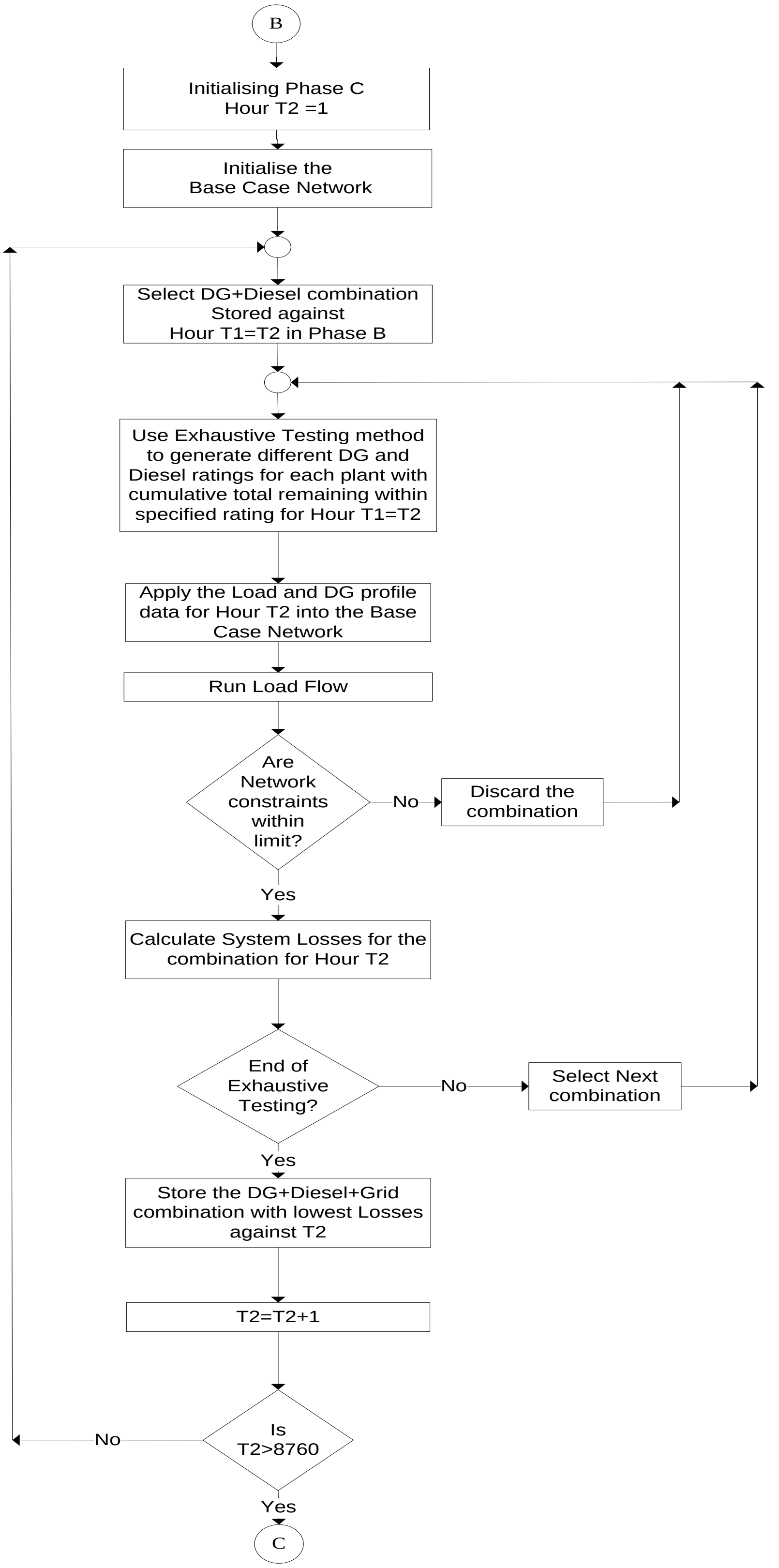


Fig 1.4 Phase C flowchart

Phase C of the algorithm is used to determine how best the generation is allocated in such a way that the generation combination minimises losses. This is achieved by calculating the sensitivity of each generating unit capacity alteration to reduce power losses of the network. The added advantage of such a dispatch is that it can reduce operating cost of respective generating units due to the reduction in power losses.

The formal procedure used in Phase C is as follows. For the hour T_2, the most economic combination from Phase B is selected. The base case network is then loaded with the DG and load profiles associated with the hour T_2. Next, combination of the various DG and diesel generator installed capacities is set to the locations of generating sites. Then, the sensitivity of generating unit output to power losses are determined by uniformly increasing/ decreasing the output power of generating units. While assessing the sensitivity of the generating units outputs the violation of voltage and thermal limits are monitored.

All the combinations that do not satisfy the constraints are discarded. For all the other combinations, the total system losses for hour are calculated. The combination that has the least amount of losses and that satisfies the network constraints and supplies the network is then stored against hour T_2.

The process is repeated for the entire 8760 combinations from Phase B. The resultant generator installed capacities from Phase C, is stored plant wise. That is, the best possible rating for a particular bus bar considering both operating and network power losses and it is determined according to the DG and load profile for each hour.

1.2.4 Phase D

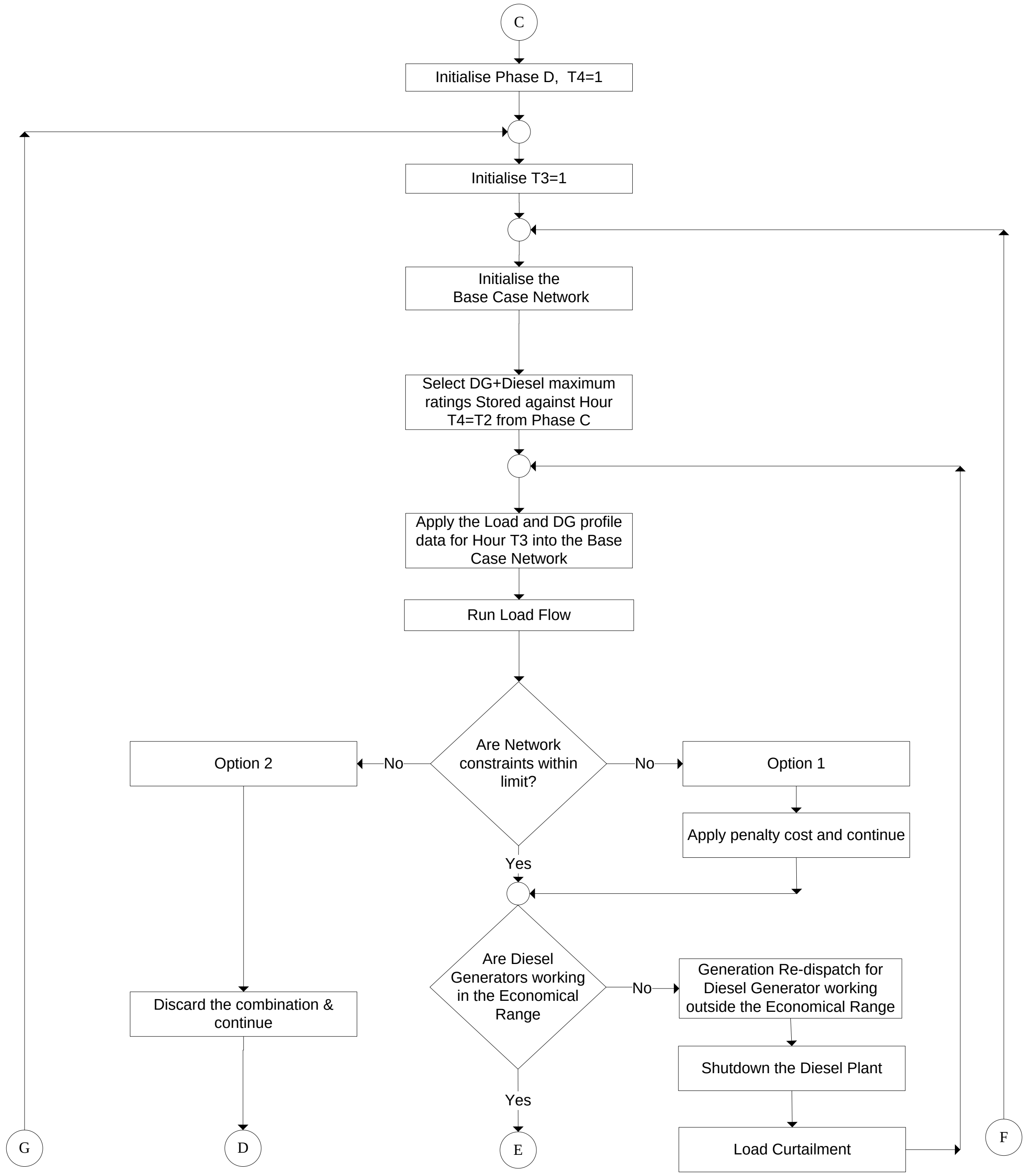


Fig 1.5 Phase D flowchart

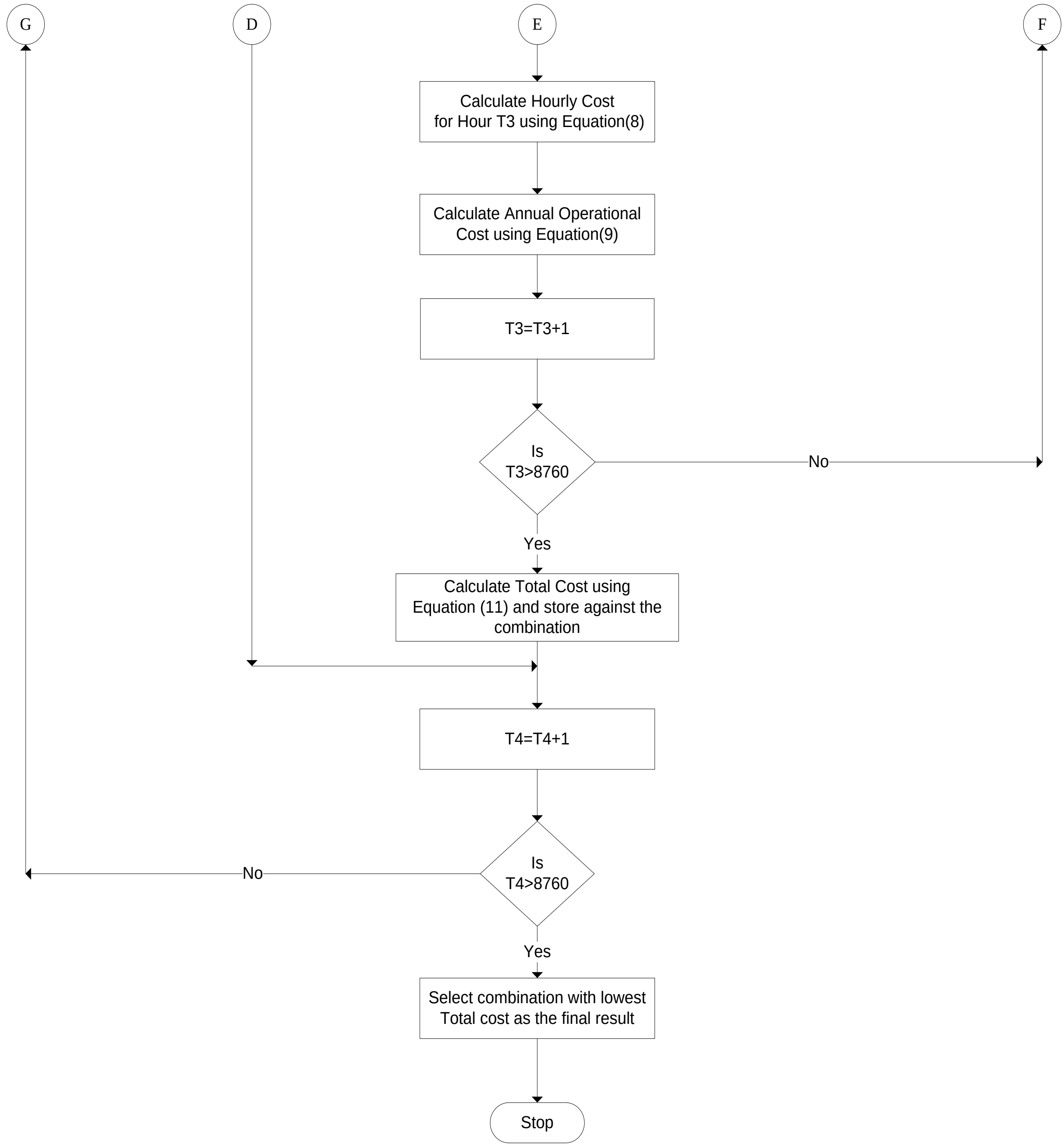


Fig 1.6 Phase D flowchart continued

Phase D of the algorithm is given by Fig. 1.5 and Fig. 1.6. Phase D provides, the most economic combination of generator ratings that result in optimal power dispatch and least network power losses for the entire year. It has two main iterations, each running for 8760 trials.

The variable T_4 is used for carrying out the first main iteration. The plant ratings obtained from the Phase C of the algorithm is used in each of the iteration of T_4. The second main iteration is used to simulate the entire year of load flow operation with each of the generator combinations stored against T_4. For each hour of T_3, the base network is loaded with the load, DG profiles corresponding to the hour T_3. The maximum rating of each generator is set corresponding to the hour T_4 from Phase C output.

For each hour T_3, the Newton-Raphson power flow is performed to determine if it conforms to the network constraints and their limits. The algorithm offers two options in case any of the network parameters are violated. Option1 provides a relaxed design procedure, in which each instance of constraint violation incurs a penalty cost that in turn gets added to the yearly running cost. Option2 is a much more constrained approach wherein, the entire combination corresponding to T_4 is discarded for any instance of constraint violations.

The diesel generators are operated only if they are operating within the efficiency region. The algorithm treats 40% to 100% of the rated output power of a diesel unit as the economic region of the efficiency curve. At each of the operating condition the diesel generator loading level is determined and if it is less than the specified 40% limit, then attempt is made to dispatch other diesel generators in such a manner so as to improve the loading of the generators. If it is still found to be operating in the uneconomical region then the corresponding unit is shutdown and the ability of the remaining generating units to operate the network as healthy is tested. The load shedding is tried however; it has the least priority.

For each hour T_3, the operating cost is found using equation (8) which when added together for the entire 8760 hours gives the annual operating cost ($C{\downarrow}(OM{\downarrow}annual\,)$) given by equation (9).

$$C_{OM_{annual}} = \sum_{k=1}^{8760} \left(C_{OM_{total_k}} + C_{loss_k} \right) \tag{9}$$

Along with operation and maintenance costs, the penalty costs associated with the power losses $[(C]_{loss_k})$ is also added to the annual operation and maintenance cost to account for the incentives for generating units that reduce the power losses or penalties for the units that increase the power losses. For each combination corresponding to T_4, the total cost is quantified as the sum of yearly operating cost and capital cost of installing the specified capacity of DG (e.g. Wind turbine units, Photovoltaic panels) and Diesel generators. The total capital cost (C_{cap}) associated with the network can be expressed as in equation (10)

$$C_{cap} = C_x \times \sum_{i=1}^{n_1} P_{x_i} + C_y \times \sum_{i=1}^{n_2} P_{y_i} + C_z \times \sum_{i=1}^{n_3} P_{z_i} \quad (10)$$

Where C_x, C_y and C_z are the unit capital costs of diesel generator, wind turbine and PV system. For capital cost calculation, the maximum ratings of the units are used. With both annual operating cost and capital cost available, the total cost (C_{TOTAL}) of the system can be expressed as,

$$C_{TOTAL} = C_{cap} + C_{OM_{annual}} \quad (11)$$

Each of these total costs is stored against the combination corresponding to T_4. At the end of the main iteration loop, all the total costs are compared and the combination corresponding to the least cost is determined through the resulted values.

1.3 Test network

Fig. 1.7 shows the schematic diagram of the network. It is divided into three zones – Zone A, Zone B, and Zone C. One of the aims of zoning is to facilitate islanding and grid connected modes of studies. The user will need to provide the control mechanism that will prevent unintentional islanding. The added benefit of zoning is that the user can test the feasibility of mini/micro-grid associated research as well as issues of inter-connection of mini/micro-grids. The user can also test the feasibility of the operation of a distribution network with the operation of distribution network autonomous controllers.

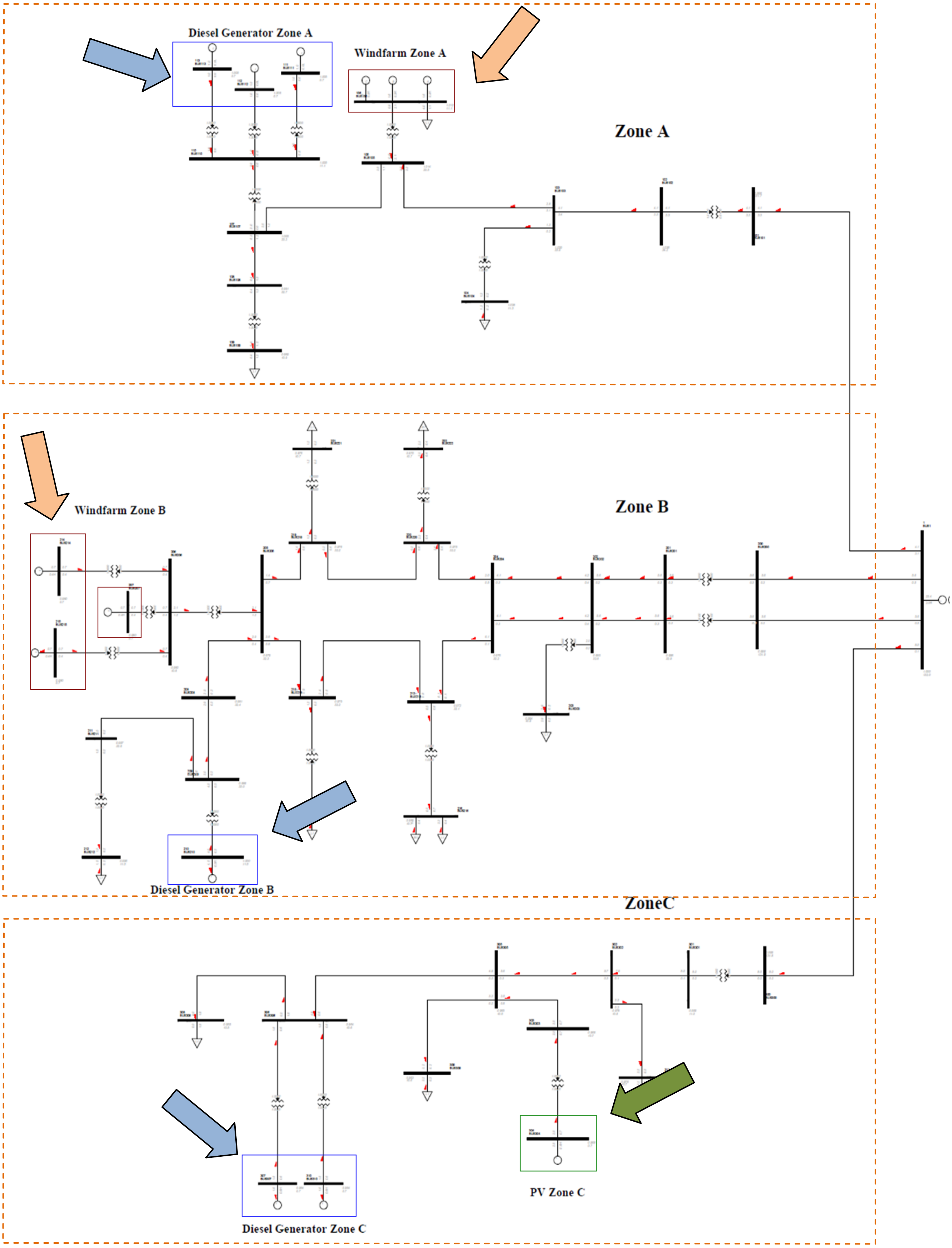


Fig. 1.7 Schematic diagram of the proposed test network

Fig. 1.8 shows the schematic diagram of Zone A part of the network. Zone A is a 13bus radial feeder type network which has active and reactive power load of 11.72 MW and 2.58 MVAr respectively. Its nominal operating voltages are from 0.69 kV at diesel generators to 132kV at the grid connection .The network demand is supplied through wind and diesel units. Under the grid connected mode Zone A demand can be supplied by the utility grid. User has the option to select the appropriate grid mode. Wind farm has three wind turbine generators with the installed capacities of 2MW, 2MW, and 2.2 MW respectively. The diesel plant has three generators of installed capacity 2.5 MVA each. The operation of diesel generators is constrained through the incremental cost curve. The incremental cost curve take into account the output power of the unit, efficiency, and cost of operation.

Fig. 1.9 shows the schematic diagram of Zone B part of the network. Zone B is 27 bus mix of meshed and radial feeder network which has active and reactive power load of 17.50 MW and 2.02 MVAr respectively. Its nominal operating voltages are from 0.69 kV to 132kV.The demand is supplied through wind and diesel units. The Zone B demand can also be supplied by the utility grid under the grid connected mode. User has the option to select the appropriate grid mode. Wind farm has three wind turbine generators with the installed capacity of 3.5 MW each. The diesel plant has generators of installed capacity of 9 MVA respectively. The operations of diesel generators can be constrained to the incremental cost curve. Zone B is specifically developed to capture the hidden effects of distributed distribution.

Fig. 1.10 shows the schematic diagram of Zone C part of the network. Zone C is a 12 bus radial feeder network which has active and reactive power load of 13.42 MW and 2.30 MVAr respectively. Its nominal operating voltage is from 11kV to 132kV.The demand is supplied through PV generation farm and diesel units. The demand can also be supplied by the utility grid under the grid connected mode. Installed capacity of the PV farm is 3 MW. Installed capacity of the units in the diesel plant is 8 and 6 MVA respectively. The operations of diesel generators can be constrained to the incremental cost curve.

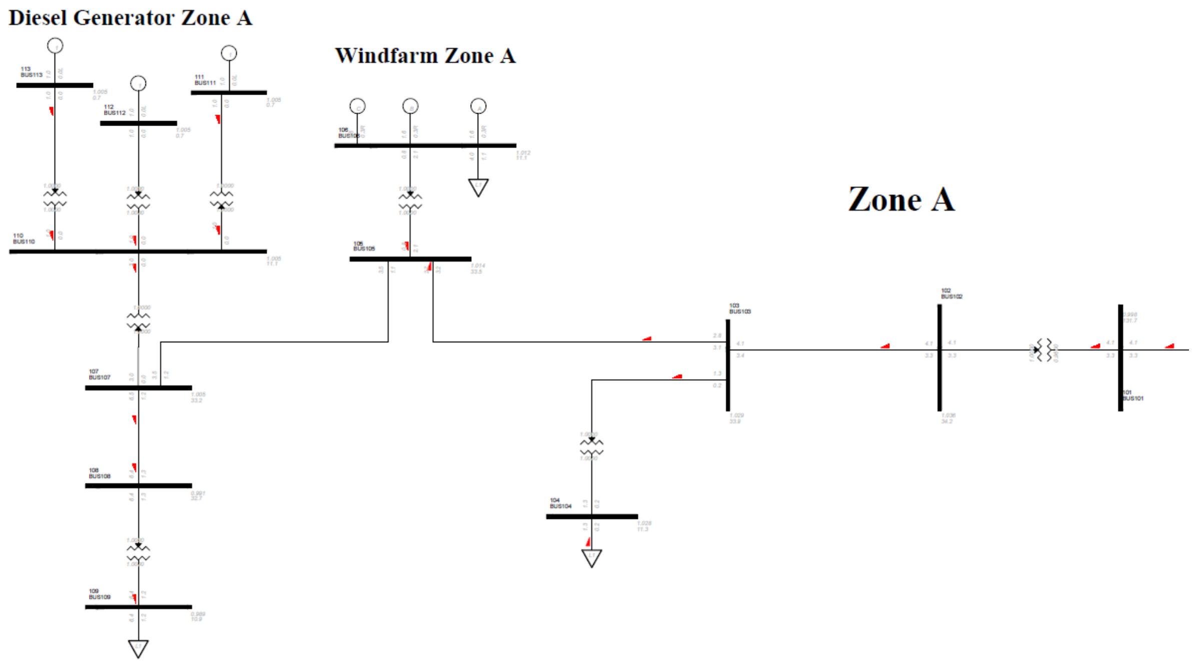


Fig. 1.8 Zone A part of the proposed network

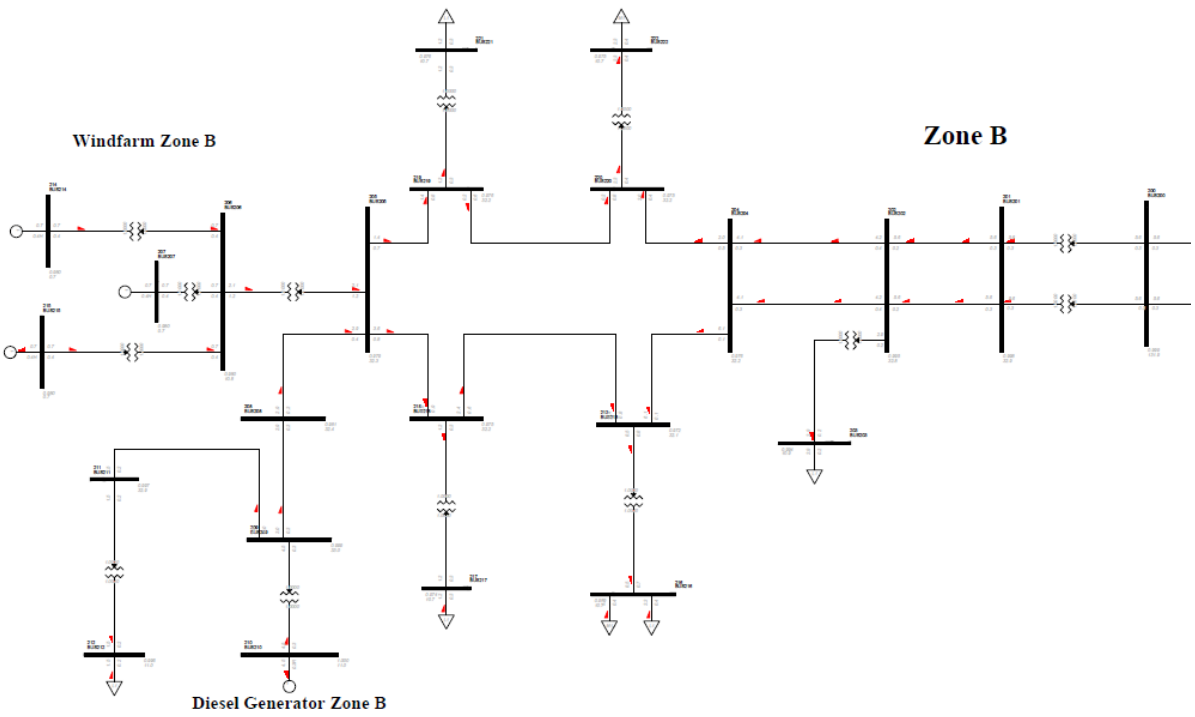


Fig. 1.9 Zone B part of the proposed network

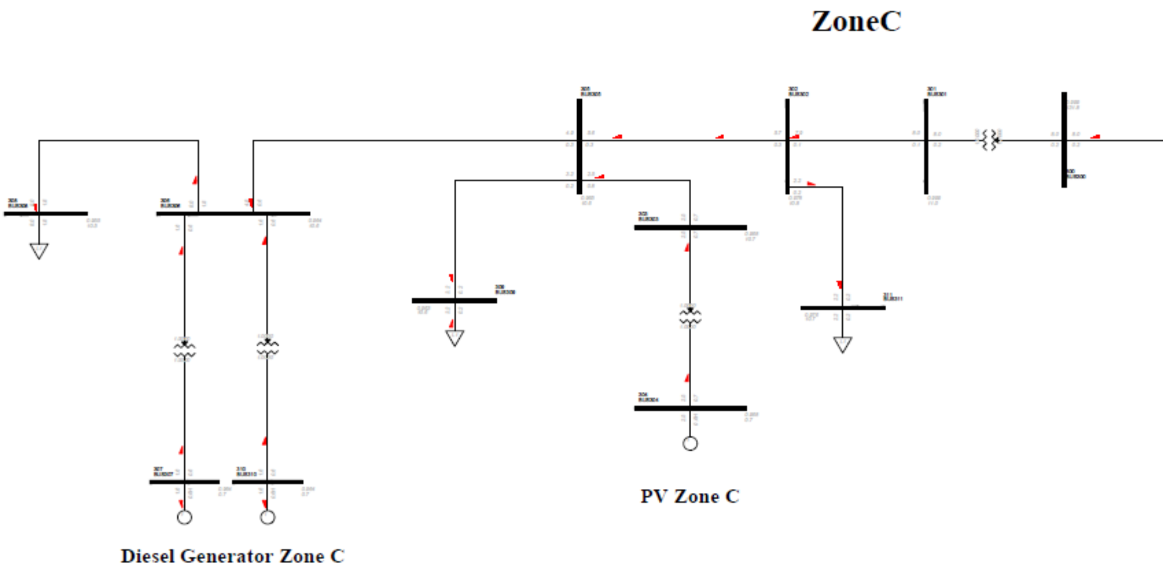


Fig. 1.10 Zone C part of the proposed network

1.4 DG and load characteristics

1.4.1 DG characteristic data

Fig. 1.11 and 1.12 respectively show the PV and Wind data respectively for a year. Data are normalised with the installed capacity of the plant. For example, if the output of 100kW wind plant at a time is 60kW due to the intermittency effects, then the output is given as 0.6.

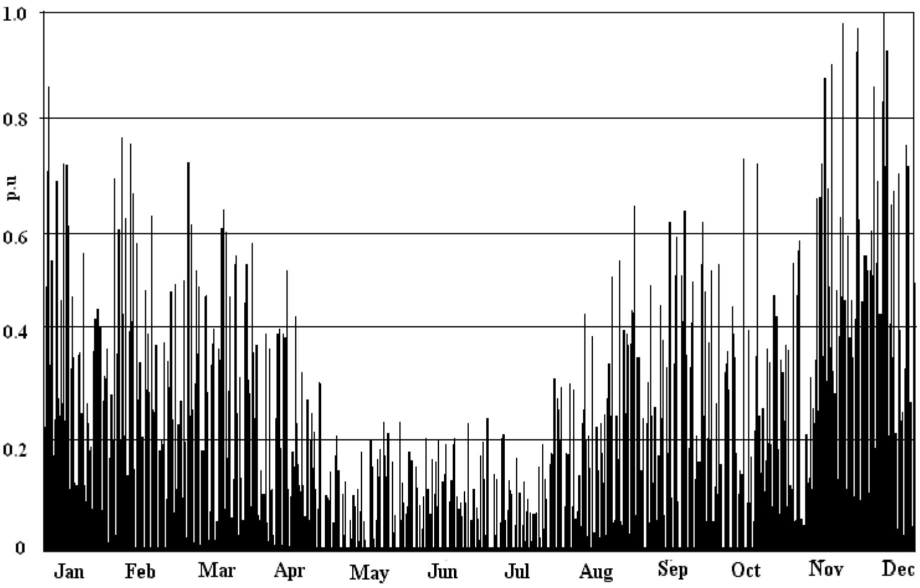


Fig. 1.11 Photo-Voltaic output characteristics for a typical year in a particular location

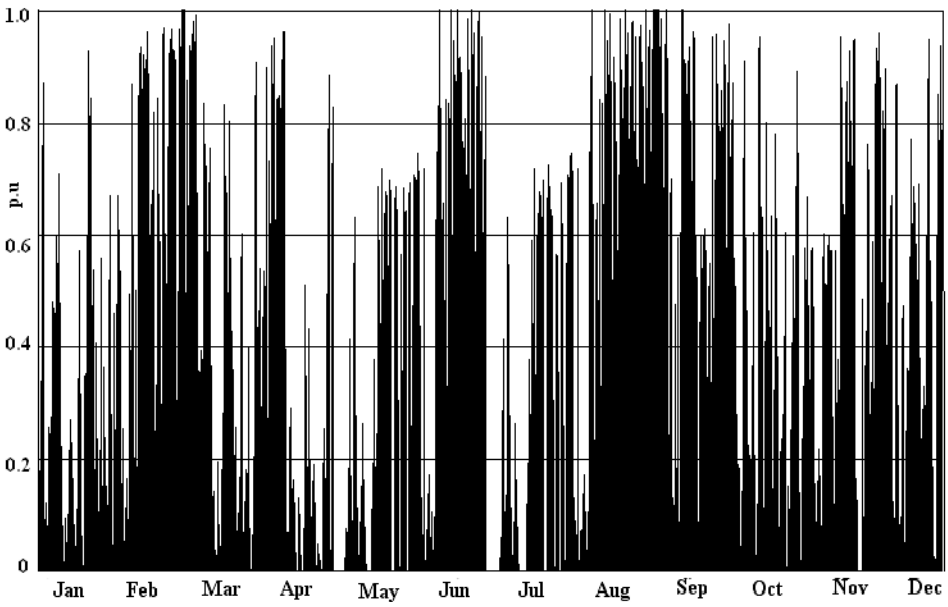


Fig. 1.12 Wind generation output characteristics for a typical year in a particular location

1.4.2 Demand characteristics

Fig. 1.13 shows the demand characteristics of each month. The same principle that is used to present the Wind and PV output is used for load characterisation.

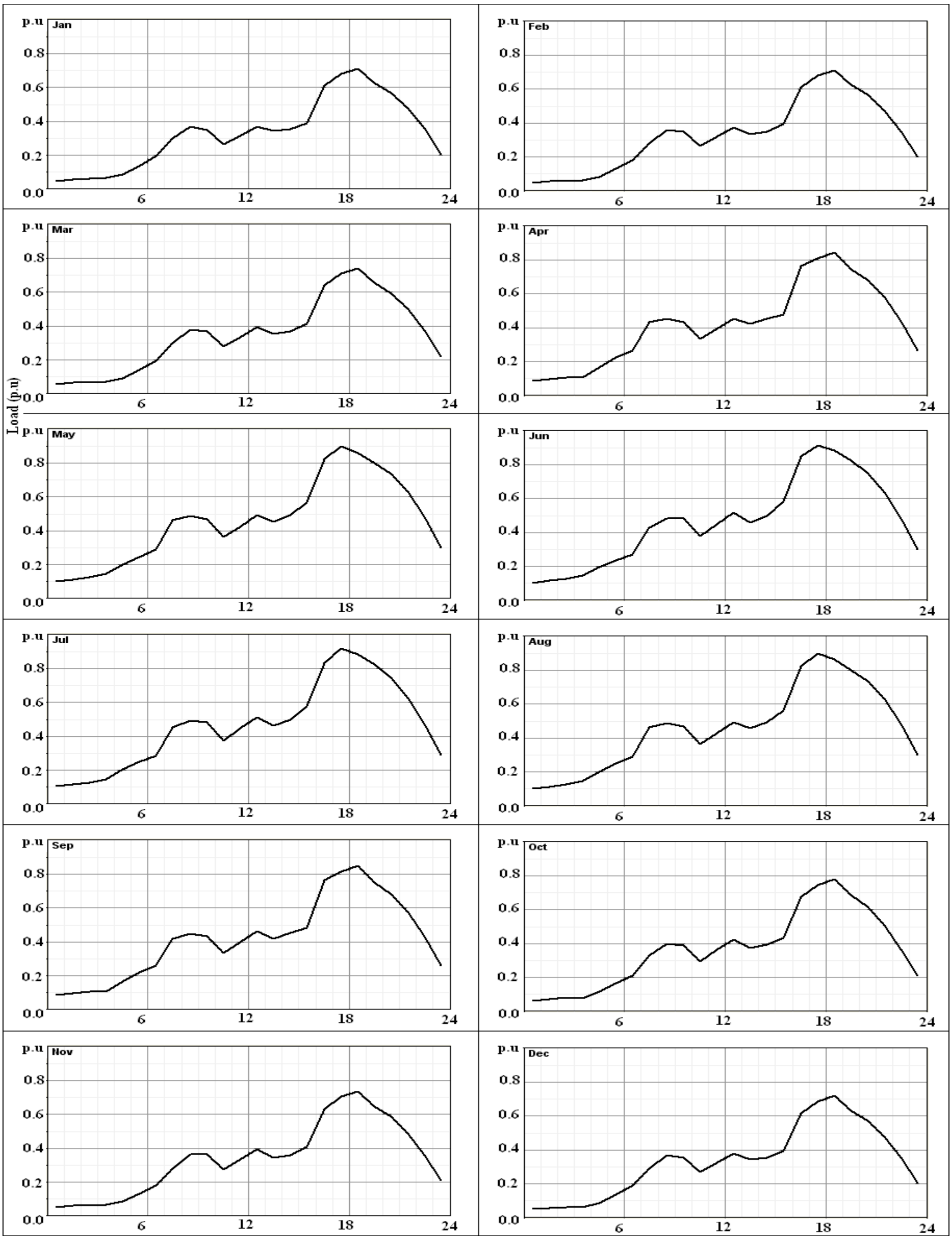


Fig 1.13 Demand characteristics of load

The horizontal axis gives the time of the day whereas the vertical axis gives the normalised load level in p.u. The normalised values are calculated using the peak demand of the load.

1.5 Software development

Algorithms proposed in section 1.2 was scripted using the PSS/E (Power System Simulator for Engineering) version 32 based interactive programming language ‘IPLAN’. ‘IPLAN’ modules can be created through any text editing software and has the ability to interact with PSS/E software to produce the desired outcome. ‘IPLAN’ subroutines interrogate the PSS/E via various routines and control the execution of inbuilt commands in the PSS/E via a series of commands called ‘PUSH’. The values entered for the ‘PUSH’ commands appear to the host application if they were entered from the terminal. It can access the whole information and data from the PSS/E software and can use the same to perform complex analytical and logical calculations to produce output values that can be fed back to the software.

PSS/E has a large collection of application program interface commands that can be used to input various types of data to execute different types of power flow calculation, create output reports etc. These commands can be either given at the program input terminal or can be given as inline commands using the ‘IPLAN’ software enabling the seamless integration of the user defined subroutines with the actual inbuilt functions present in the PSS/E software package.

1.6 Case studies

Scenarios that represent realistic operating conditions of distribution networks are investigated with the use of developed test network which was proposed in the section 1.3 (and also in the previous report).

1.6.1 Impacts of load variation effects

At first the network loading is varied in percentage steps to determine the optimal size of generators taking into account network constraints, cost functions, power losses. Fig. 1.14 shows the total installed capacities of operating conditions corresponding to weekly based scenarios in a sample year. The vertical axis gives the total installed capacities the wind, PV and diesel generators that will provide the minimum total cost (sum of cost of operation, start up cost, and capital cost), in MW, while the horizontal axis provides the entire year in weeks time scale.

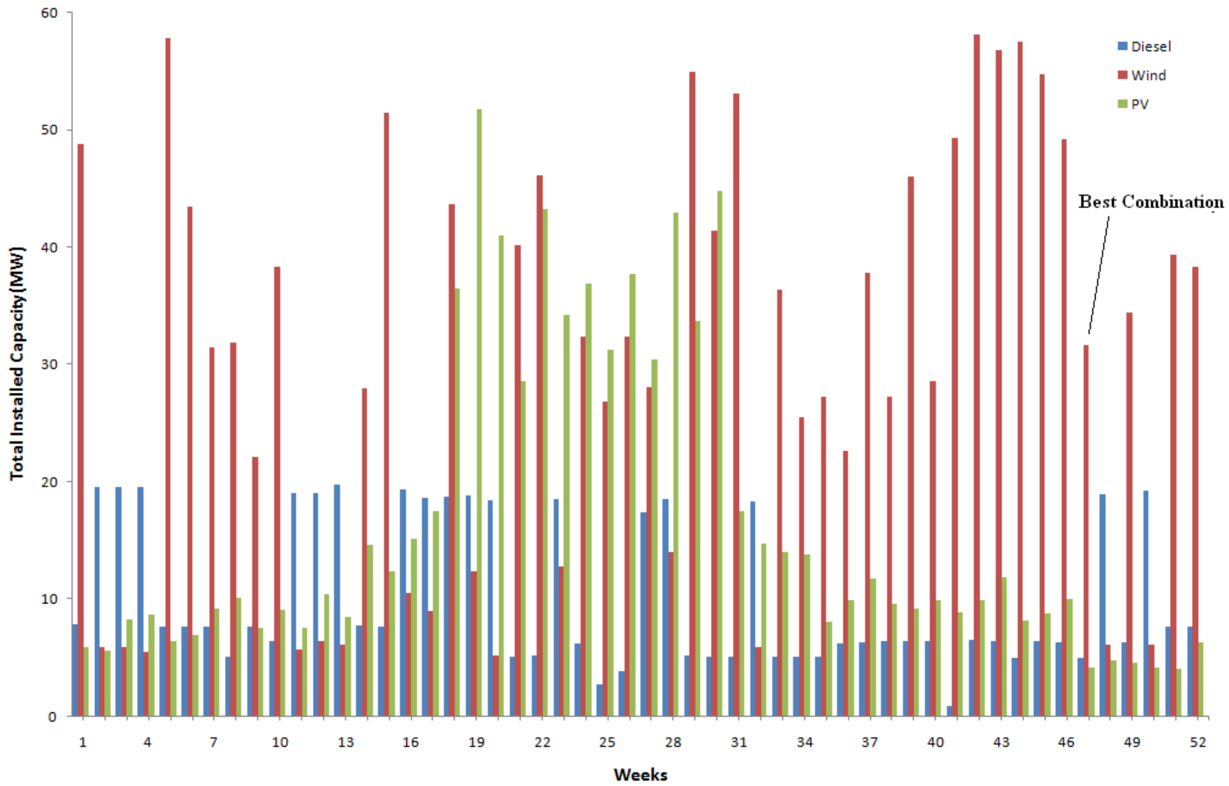


Fig 1.14 Total installed capacities of generating technologies needed to meet weekly operating conditions with base case loading

For each week, a combination of optimal ratings of Wind, PV and diesel generating units are estimated. These ratings vary for each week, depending on the load and DG profile. For example, a week with lower wind gust requires using higher capacity wind turbine units in order to meet the same level of load subject to safe operating limits of wind turbine generators.

Installed capacities of each of the most economical generating unit combinations corresponding to each week of the entire year is obtained using the algorithm presented under the Phase B. Each of the generating unit size corresponding to each week is fed into Phase C and thereafter Phase D of the algorithm in achieving the goals.

Installed capacity of the generating unit given at the week 47 gives the most economical combination that can fulfil all the operating conditions of the year. This is highlighted in Fig. 1.14.This scenario gives the optimum operation because it is the only scenario that can supply the electricity to consumers during the whole year without violating the constraints and utilising most of renewable generation yet providing least cost of operation. Thus, the week

47 is representative for selecting the least cost of operation scenario and provides the added benefit of optimal combination of distributed generating units. Identification of such an operating condition is infeasible without the application of exhaustive algorithms because of simultaneous variation of several factors through the simulation period. Applications of random selective algorithms do not guarantee the most economical combination and may skip the critical operating condition leading to erroneous conclusions.

The network base case load was varied from 30% to 130%. The loads of new scenarios were also applied with the DG and load profiles. The Figs. 1.15 to 1.24 show the variation of total installed capacity against the base case load from 30% to 130% of the base case load.

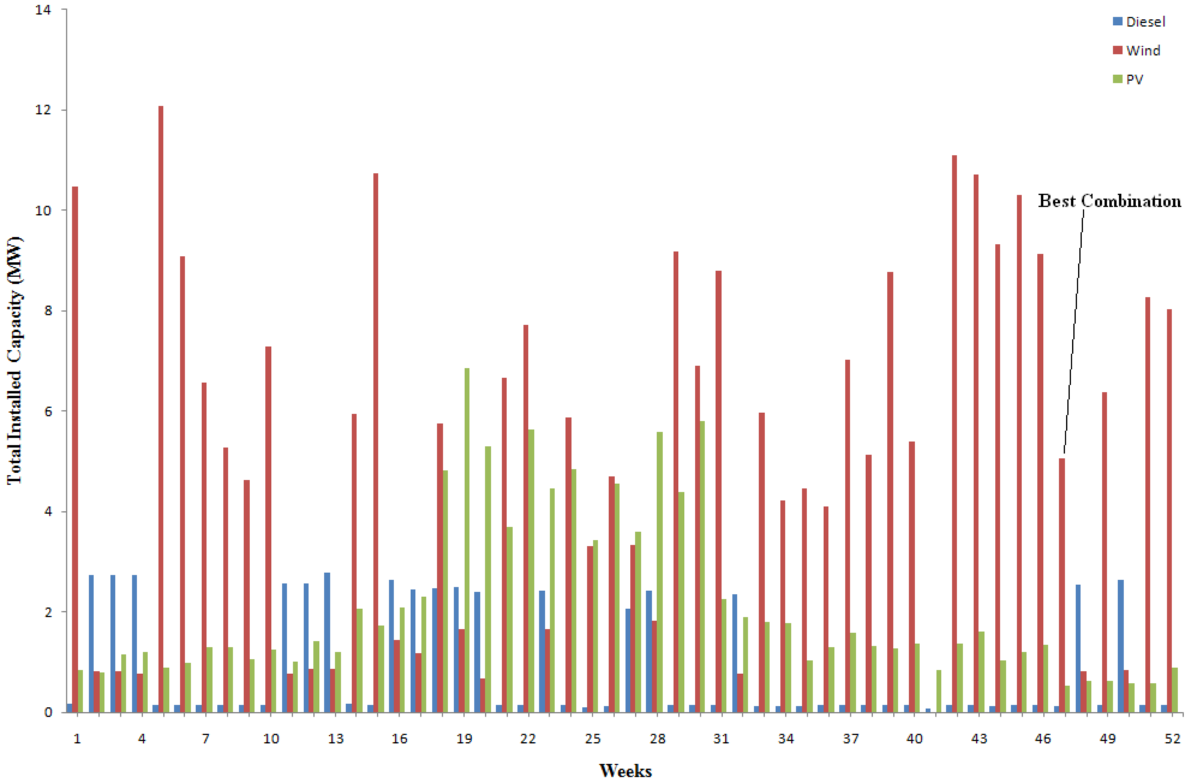


Fig 1.15 Generator ratings for 30% Base Case Load

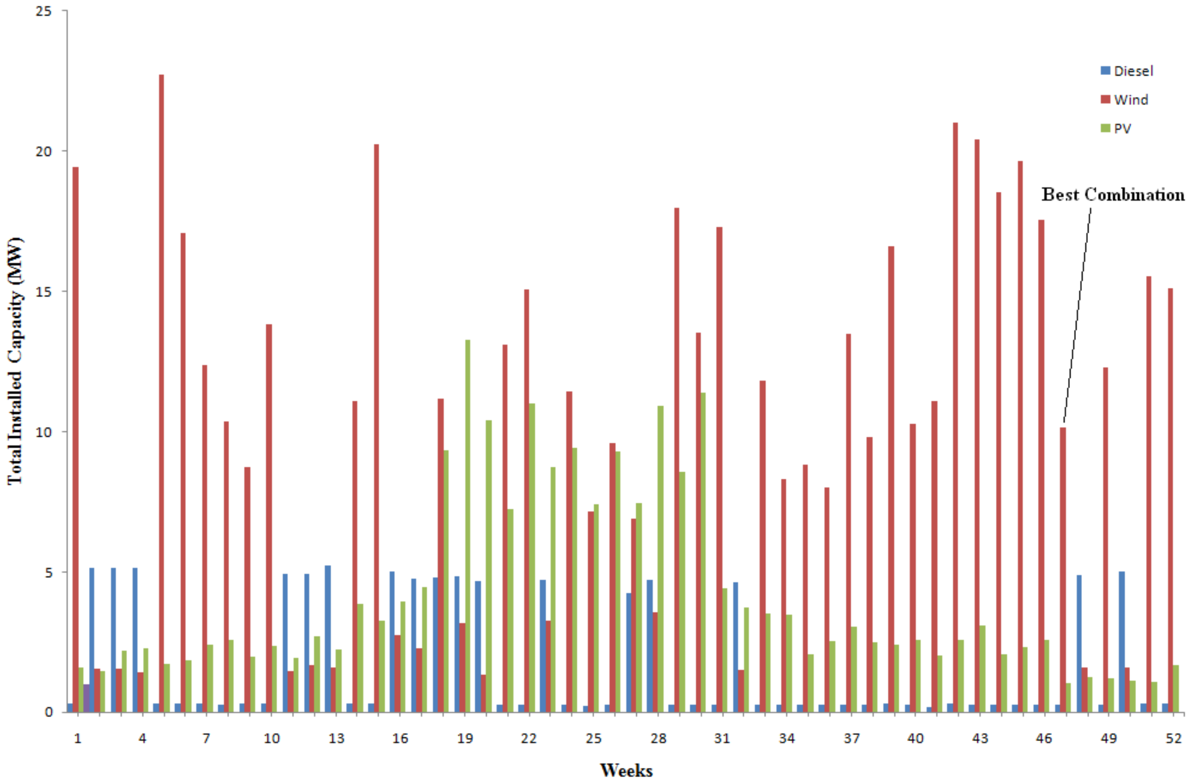


Fig 1.16 Generator ratings for 40% Base Case Load

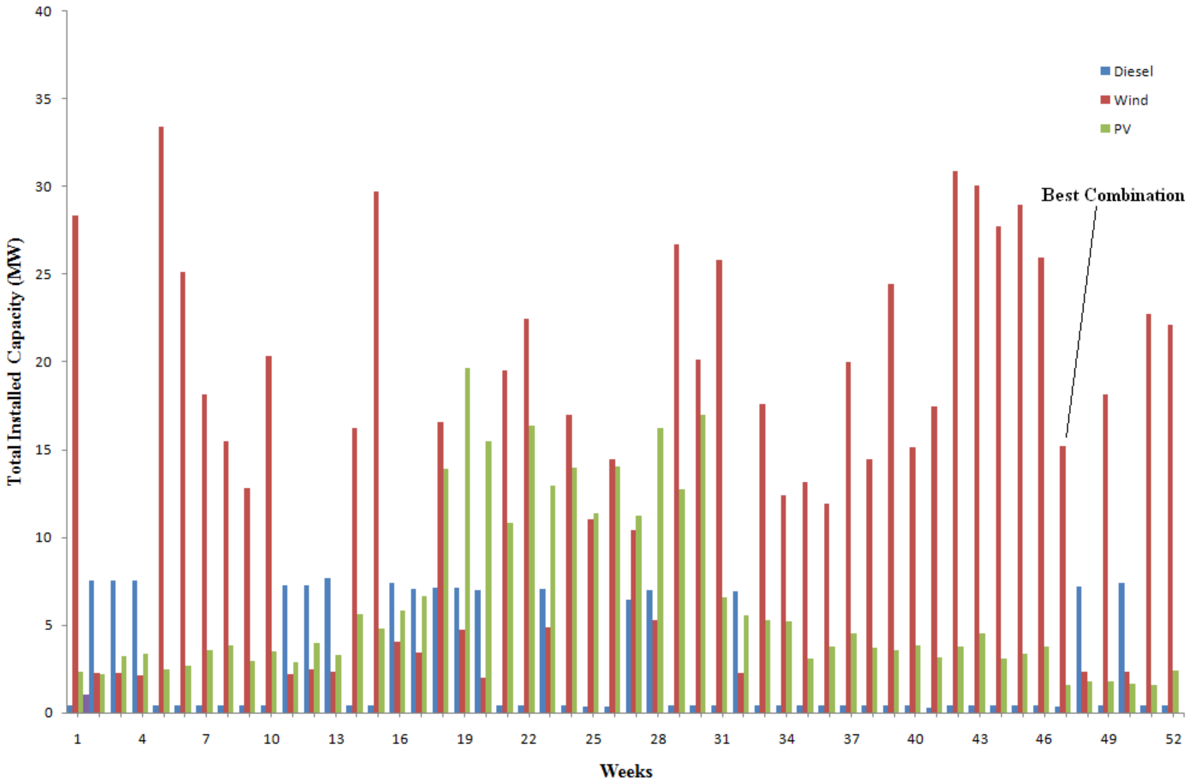


Fig 1.17 Generator ratings for 50% Base Case Load

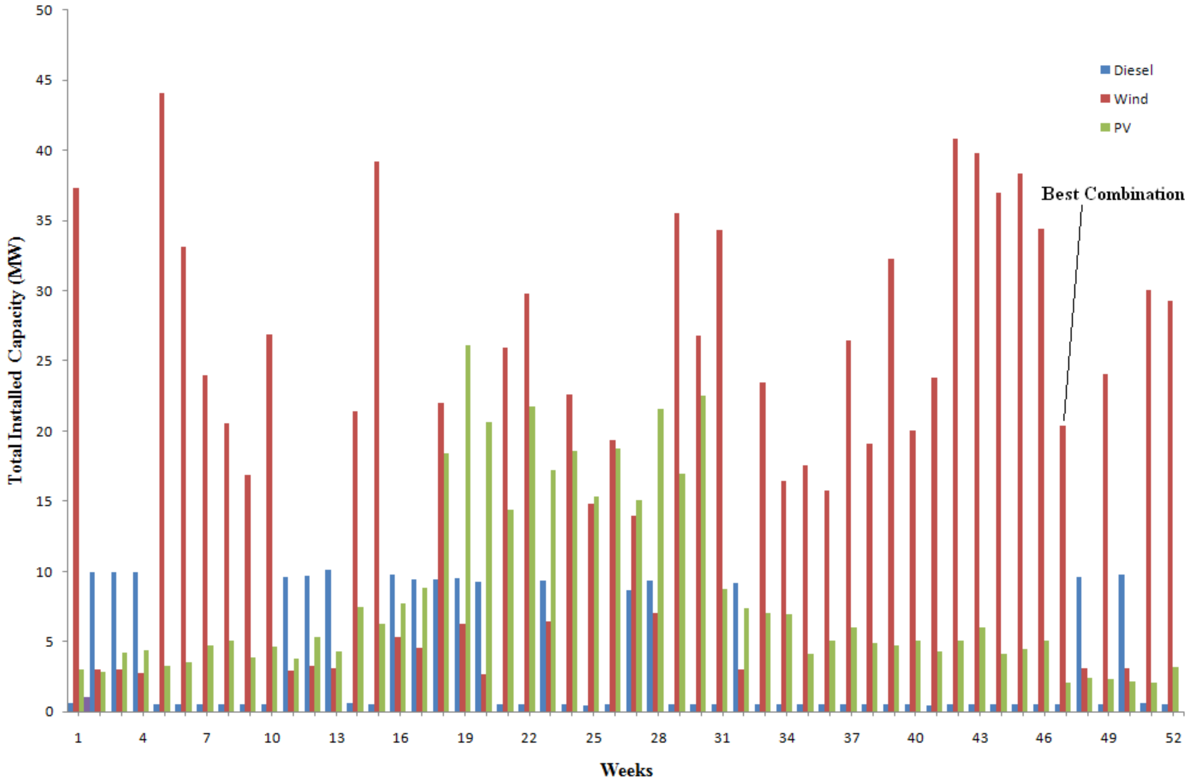


Fig 1.18 Generator ratings for 60% Base Case Load

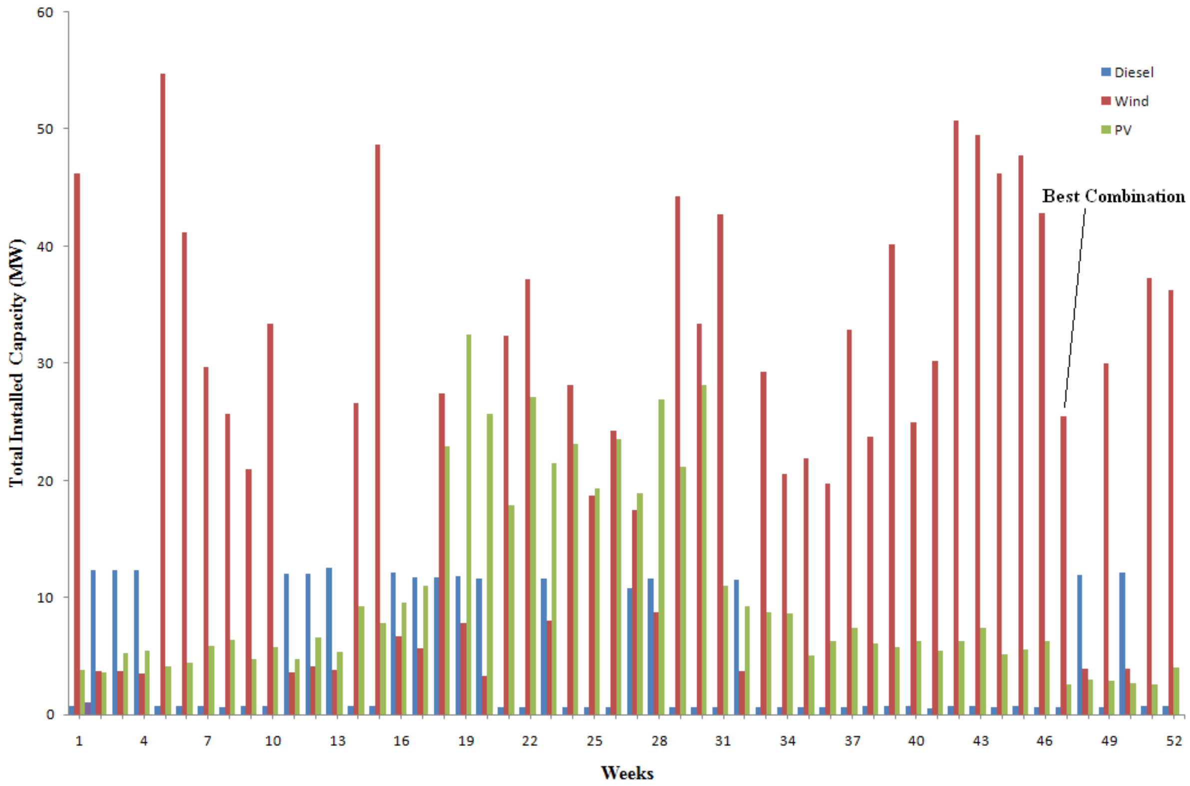
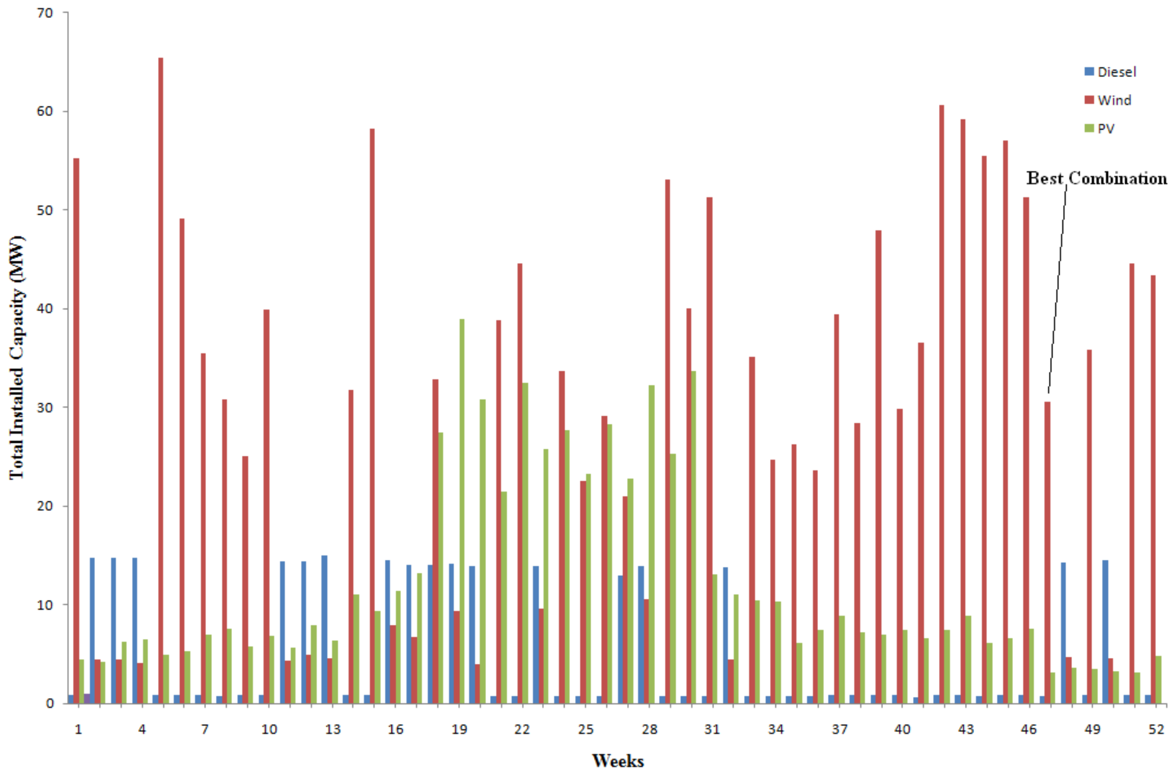


Fig 1.19 Generator ratings for 70% Base Case Load



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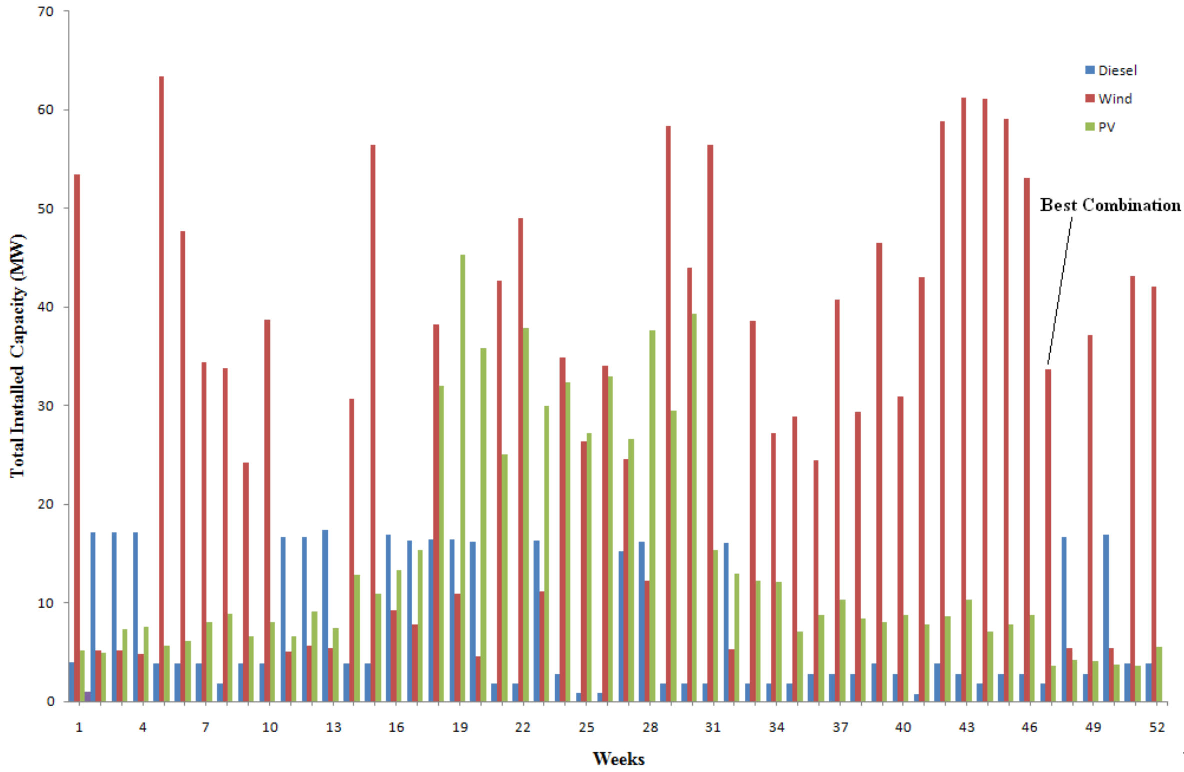
ig 1.20 Generator ratings for 80% Base Case Load



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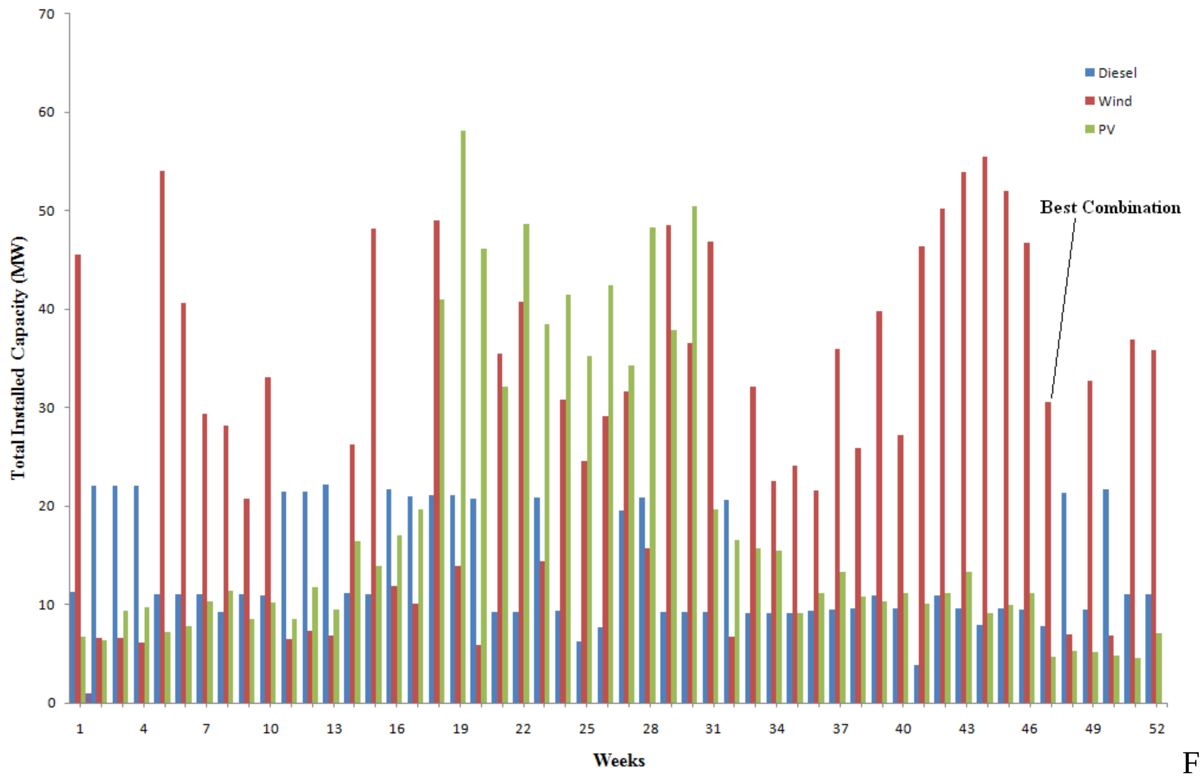
ig 1.21Generator ratings for 90% Base Case Load



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ig 1.22Generator ratings for 110% Base Case Load

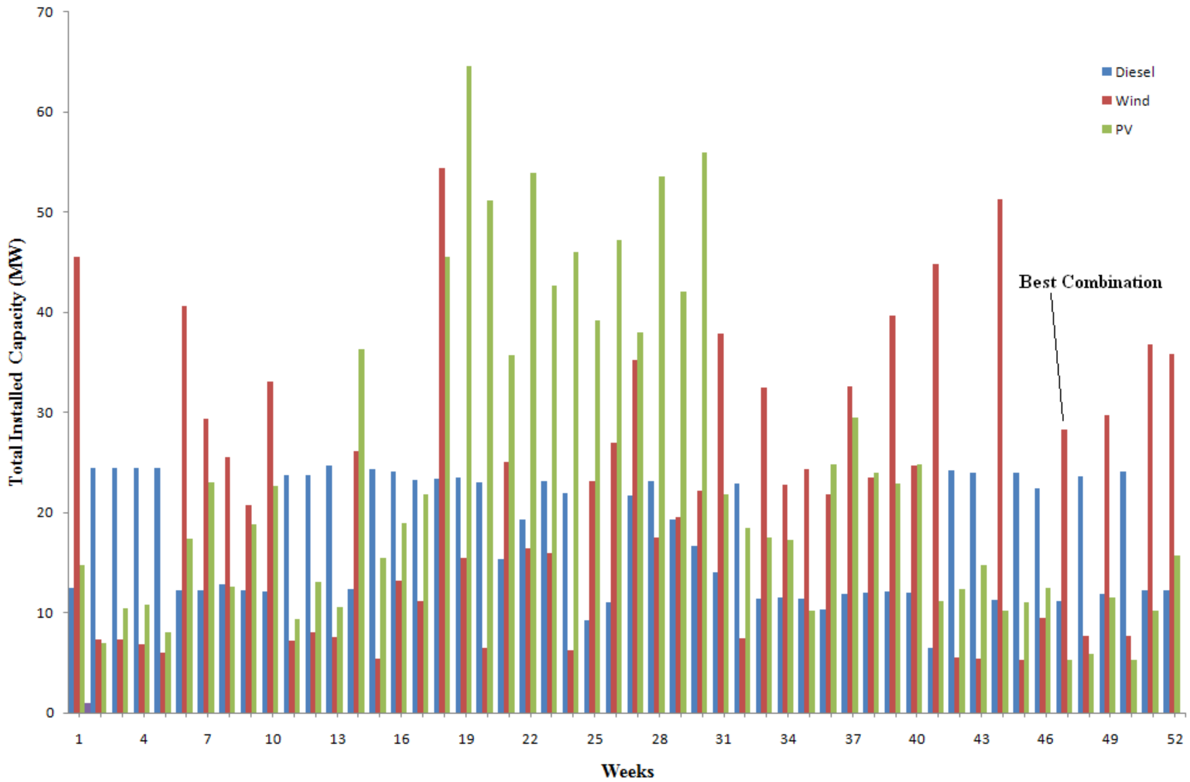

Fig 1.23Generator ratings for 120% Base Case Load

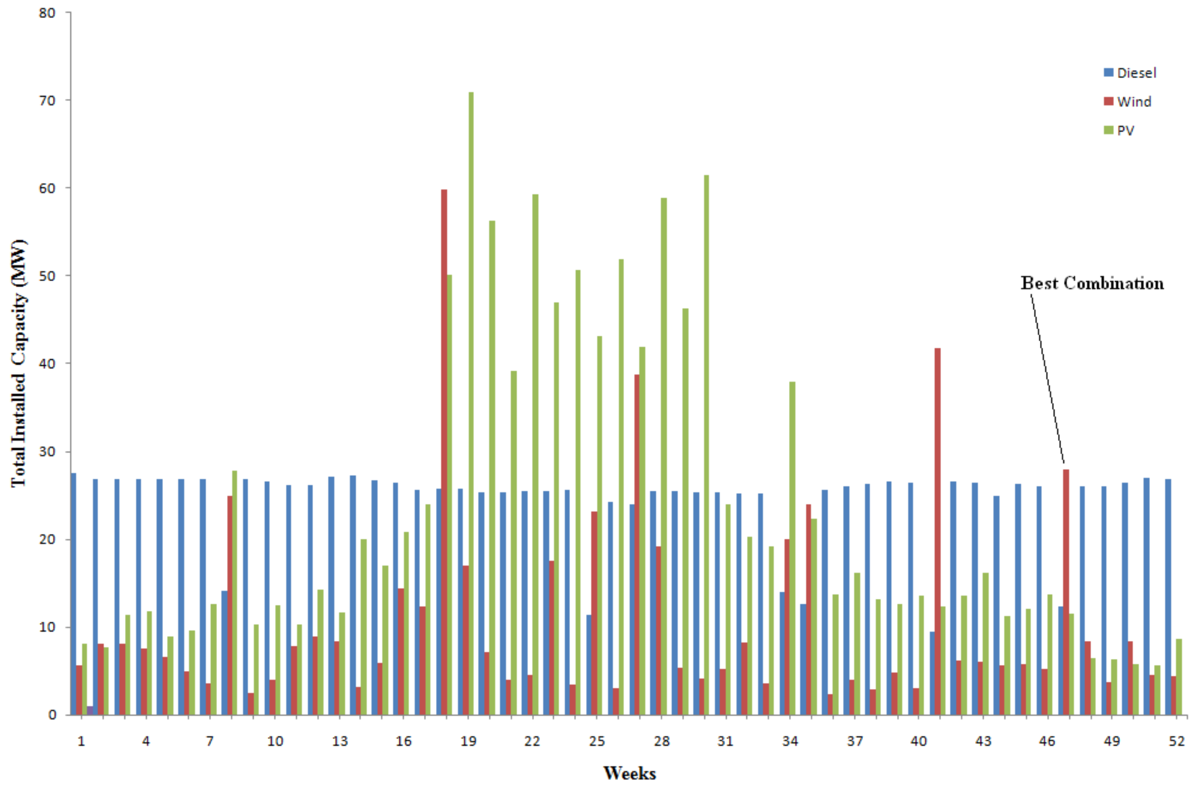

Fig 1.24Generator ratings for 130% Base Case Load

Results depicts that the magnitudes of installed capacities of generating units are varying for the entire range of load, although the most economic generating unit size combination results at the week 47.

Fig. 1.25 shows the total installed capacity of most economic generating unit combination of all studies. Load at 90% of the base case load gives the largest required installed capacity to meet the operating conditions of the selected year. This is because the wind units of this scenario provide more power than other generating units. Network constraints and loading level together with physics of power flow limit injecting power from the generating stations that results higher demand from wind units resulting an increase in installed capacity. At 90% of full load, the penetration of Wind and PV is more than that was for the full load condition. This can be attributed to greater relaxation available in the network voltage limit and thermal limit constraints and indicates that the network mostly absorbs wind energy.

However, loading from 30% to 80% of the base load follows a linear variation of total installed capacity which contributes to most economical configuration.

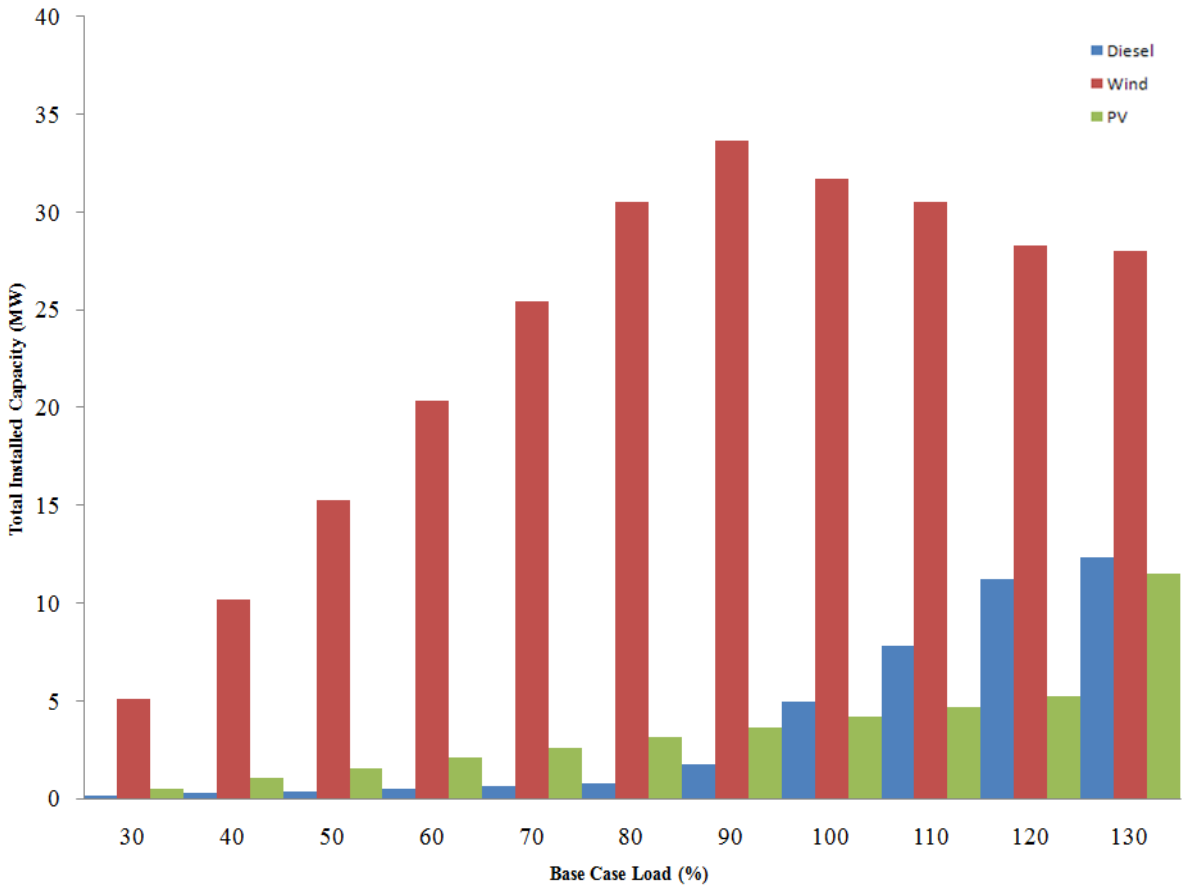

Fig 1.25: Sum of the generating unit sizes vs. variation in system load

Once the base case loading is increased above 100%, the most economic combination demands more power from diesel units, resulting in a reduced penetration level of wind power. This situation arises because the extra capital cost of wind units is not economical with larger installed capacities demanded by increased loading levels to meet a safe operating condition of the network. The network operation is infeasible beyond 130% of base load due to presence of load flow divergence.

1.6.2 Effects of cost functions on economic combinations of hybrid units

The previous case studies performed to investigate most economical generating unit sizes based on given cost data. However, in reality the cost factors of a distribution network can be varied due to the geographical location and other constraints that include operating philosophies. For example, there may be occasions where the capital cost is significantly large compared to the operating cost. In those circumstances, the developed algorithm can be used to determine the specific influence of each cost component when they are mutually exclusive. The following case studies focussed on sensitivity of cost factors to the most economical combination of generating unit sizes. The cost factors referred here is the cost component that comes under total cost. The total cost to determine the most economical unit sizes is the capital and operation cost. Start up cost is merged within the cost of operation by shutting down the fossil fuelled plant (diesel units) when they attempt to operate at the low efficiency curve.

In this part of the study, three different scenarios are created. They are built upon:

- Primary determining cost factor of most economical unit sizes as capital cost
- Primary determining cost factor of most economical unit sizes as operating cost
- Primary determining cost factor of most economical unit sizes as capital cost and cost of operation

Fig. 1.26 to 1.28 show the results of each cases listed above.

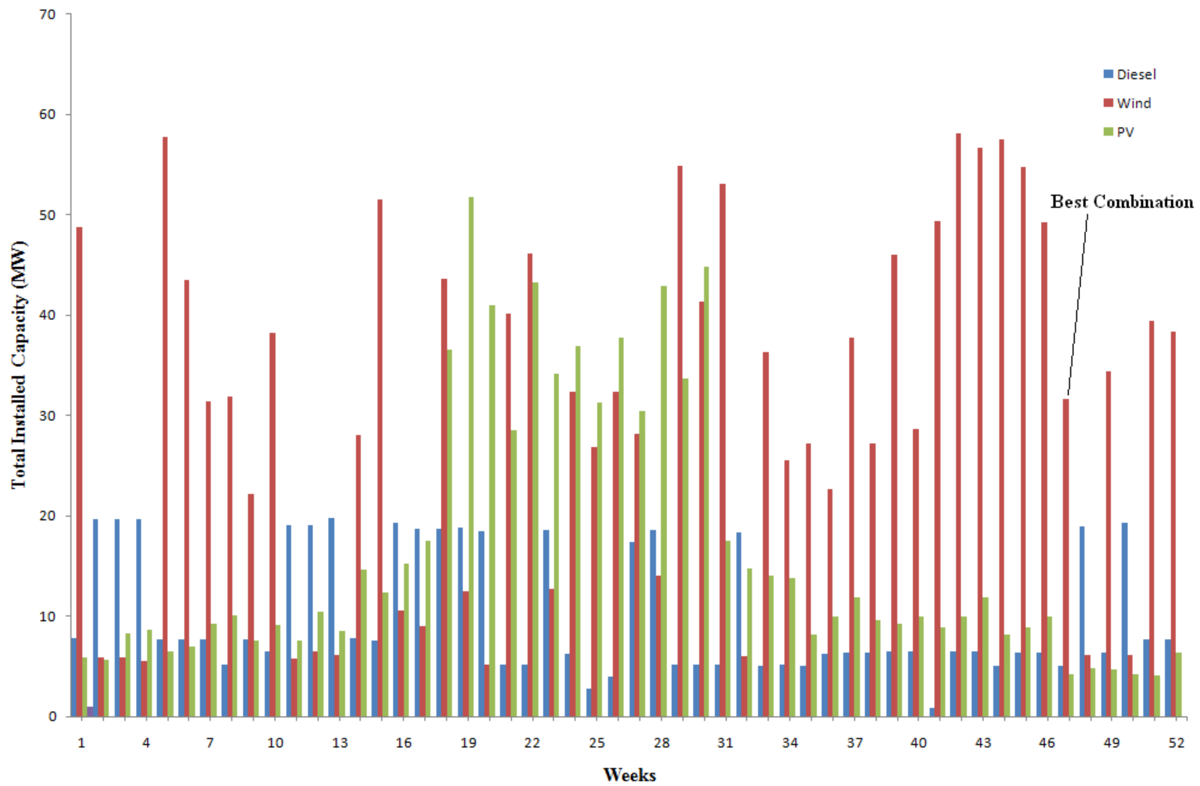

Fig 1.26: Generating unit size determining factors as capital cost

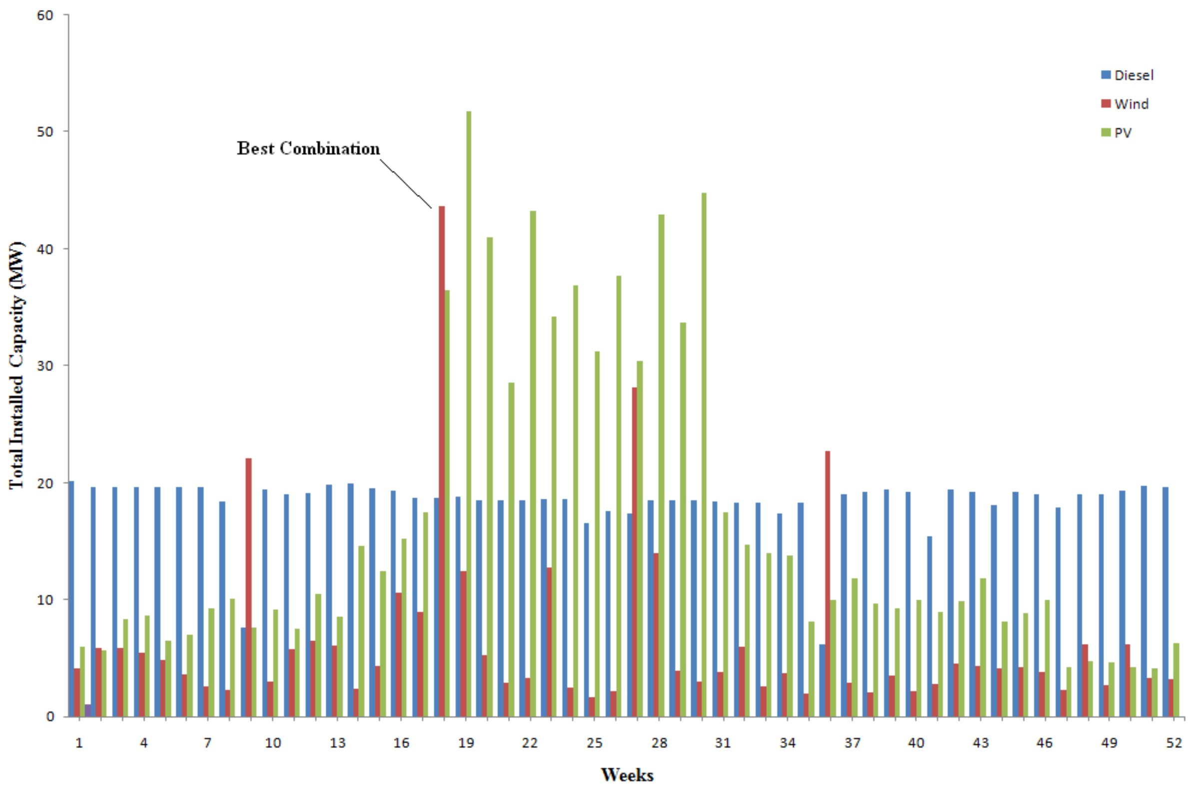

Fig 1.27: Generating unit size determining factors as operating cost

Figure 1.26 shows the results obtained when only the capital costs of the DG generators and diesel generators were considered in the algorithm. The ratings so obtained do not depend on the operating costs, and such is independent of the actual power output produced by each of the generators and solely depends on the maximum ratings of the generators. Fig. 1.27 gives the output corresponding to a scenario where in the operating cost alone is considered for the economic calculations in the algorithm. The variation in the results obtained from the two methods can be clearly seen from the Figs. 1.26 and 1.27.

In the case of diesel generators, the scenario which takes into account the operating cost alone provides a more uniform result throughout the entire year. The average rating is found to be more than the normal ratings when compared to the scenario where capital cost is considered. In order to generate more penetration levels from DG resources, the capital costs of diesel generators were set to be higher than DG resources. When the capital cost was taken out of the problem formulation, the injections from diesel increases. On the other hand, the high set values of diesel units enables DG units to inject more power when they are flexible.

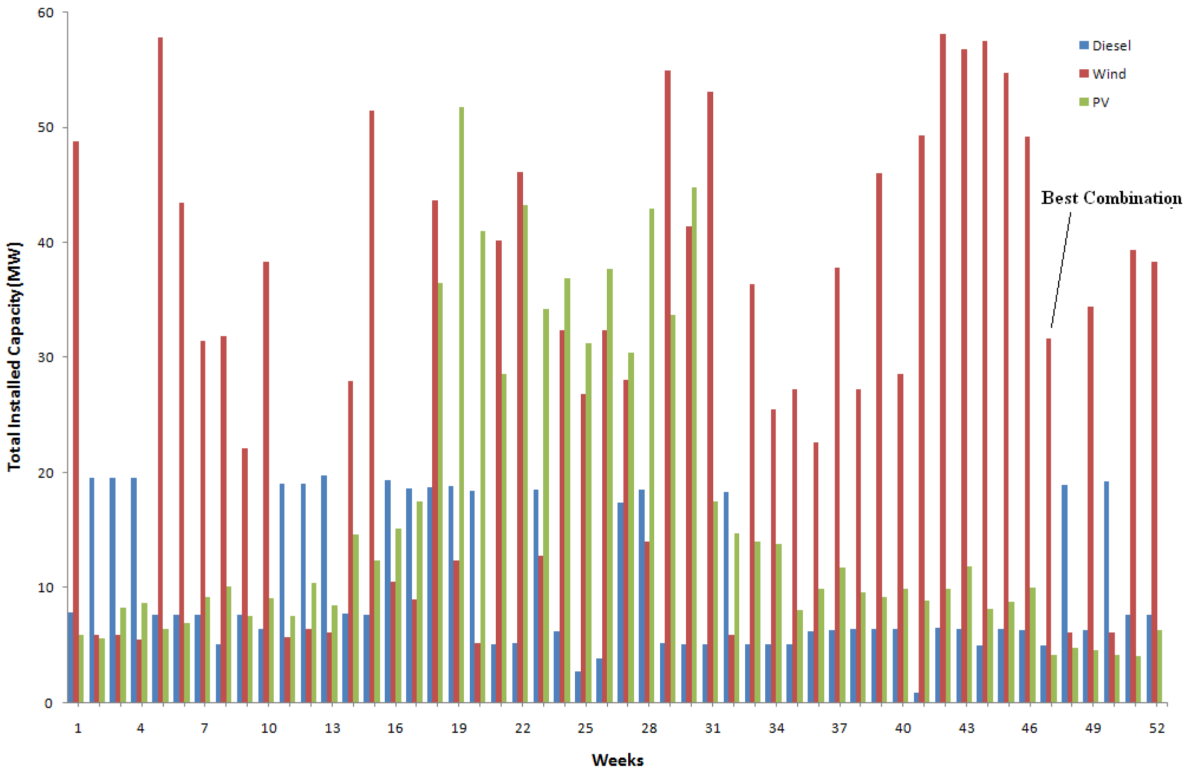

Fig 1.28: Generating unit size determining factors as capital and operating cost in combination

The results corresponding to the scenario where both operating and capital costs were considered in the study is depicted in Fig. 1.28.

The results depict a useful insight of networks that are integrated with small number of wind and PV plants against the large scale integration. One of the message comes out of this part of the study is the generator unit sizing needs case by case cost analysis in applying for a particular network. Similar arguments exist in published literature however they are based on technical merits of specific studies and not the combinatorial effects of technical and economic benefits. The message comes through this part of the investigation represents both technical and economical aspects of generator unit sizing and gives a unique massage in achieving global benefits.

1.6.3 Effects multiple combinations of DG units

Investigations were extended to study the effects of using various combinations of the distributed generation technologies on the total cost of the system and how such combinations affect the economical value of the combination. Some of them are presented in Fig 1.29 to Fig 1.31.

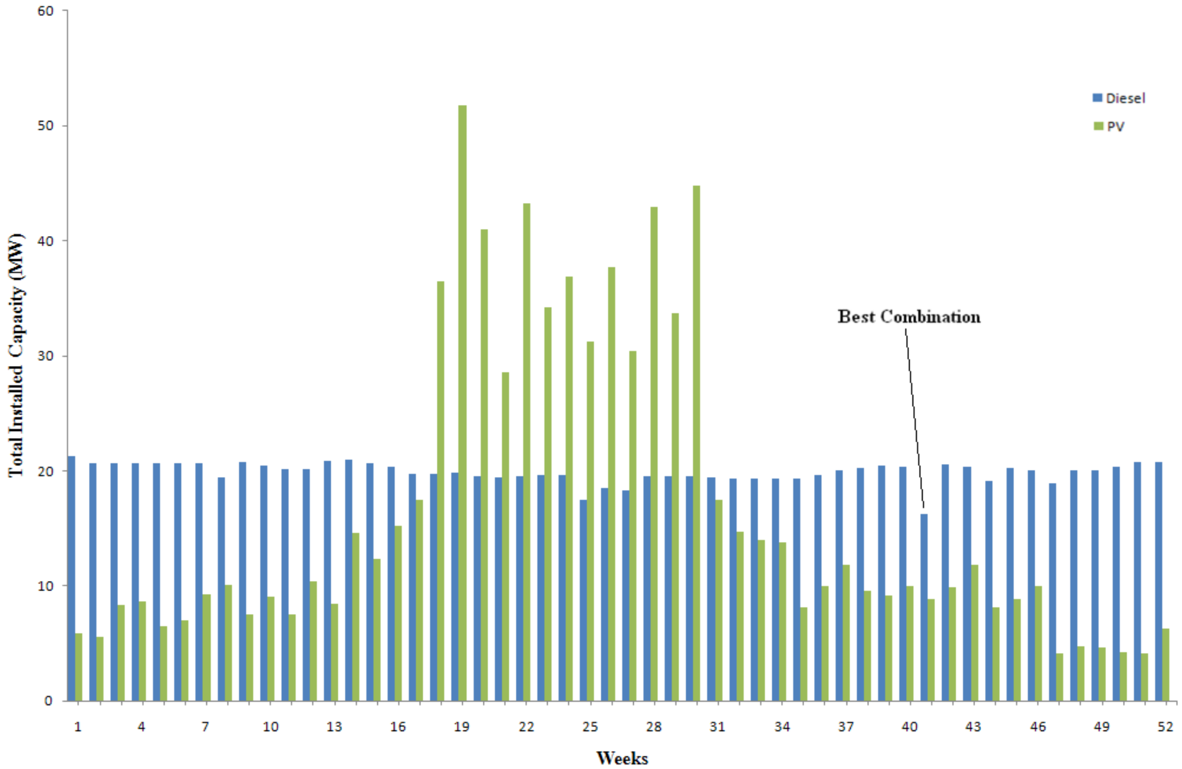

Fig 1.29 Diesel and PV Generation

With no wind turbines is taken into account for the problem formulation, most of the output is supplied by the diesel generating units, then the remaining load is supplied by the grid and PV. The required installed capacity of PV varies according to the variation of the PV profile; however, the total power generation from PV is considerably low. This is because the thermal limit constraint in the middle part of the existing network limits the maximum possible output injecting to the network from the centralised PV system. The results depict that the most economical combination arises at the week 41 of the year in which the diesel unit rating are deemed low.

At the most economical combinations of generating units, a major portion of the network load was supplied by the grid along with diesels. This suggests that PV operating with diesel units without the injection of power from wind units are highly uneconomical when compared with the combination operates with wind units. This reason behind the situation is that the significantly increase in operating cost due to high diesel powered unit participation in a year and the capital cost of diesel units that is required to supply the said demand.

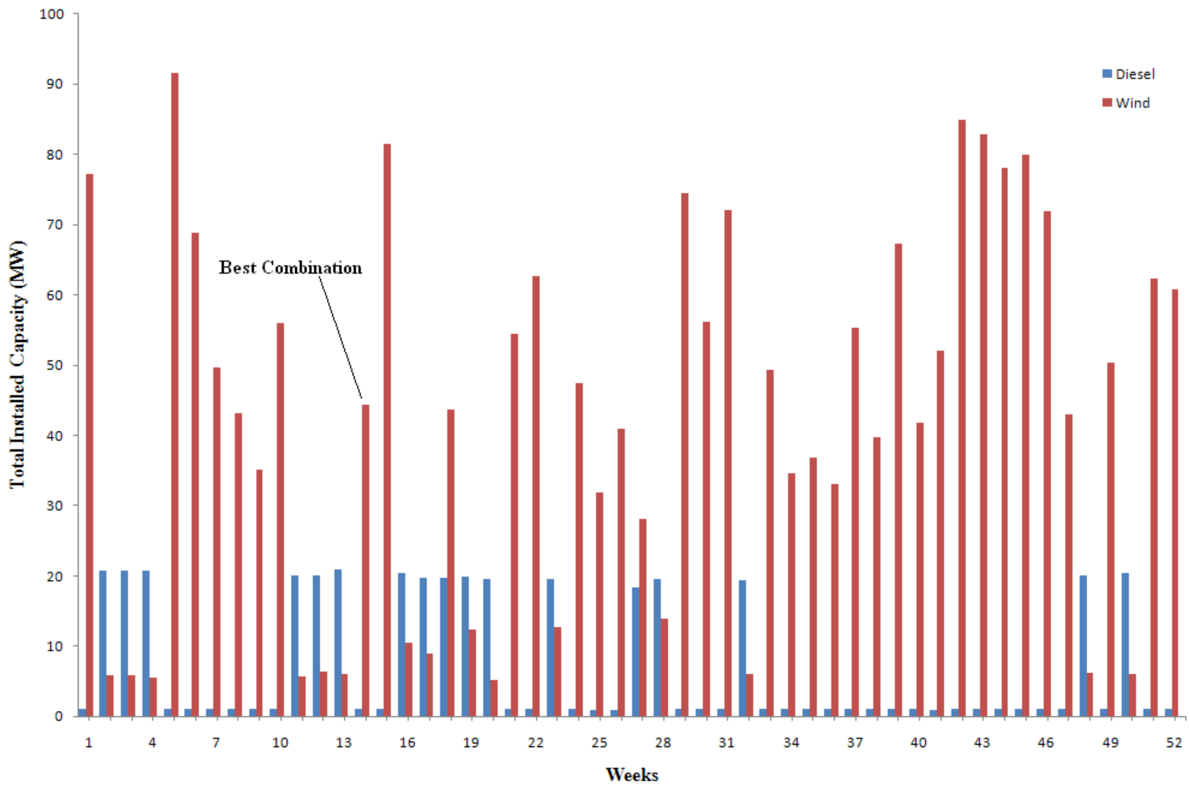

Fig 1.30 Diesel and Wind Generation

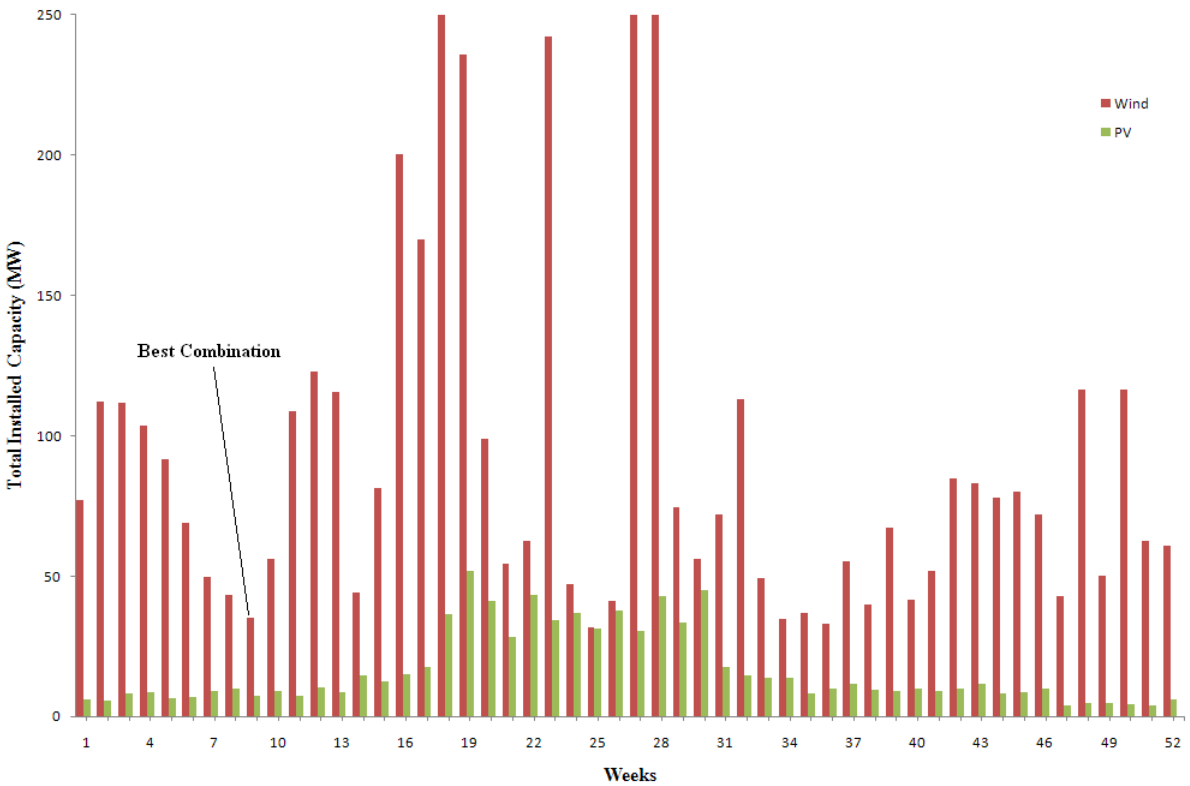

Fig 1.31 Wind and PV Generation

When the network demand is supplied by the wind turbine units, diesel units, and the grid the most economical generating unit combination results at the 14th week of the year. Fig. 1.31 shows the detailed results of this situation with other weeks of the year. The generating unit combination provides the lowest total cost even when the PV system presents. Therefore, in this particular network, the best option is when there is no PV system present, with the load being supplied by the combination of diesel, wind and grid. However, the further investigations are necessary in order to justify the above argument under distributed PV installation in a distribution network.

Fig 1.31 shows the wind and PV generator ratings when no diesel generator units were present in the power system network. In this operating condition, the grid supplies the extra load that was not met by the Wind and PV unit combinations due to very low wind gusts and solar irradiation effects.

1.6.4 Effects of power losses

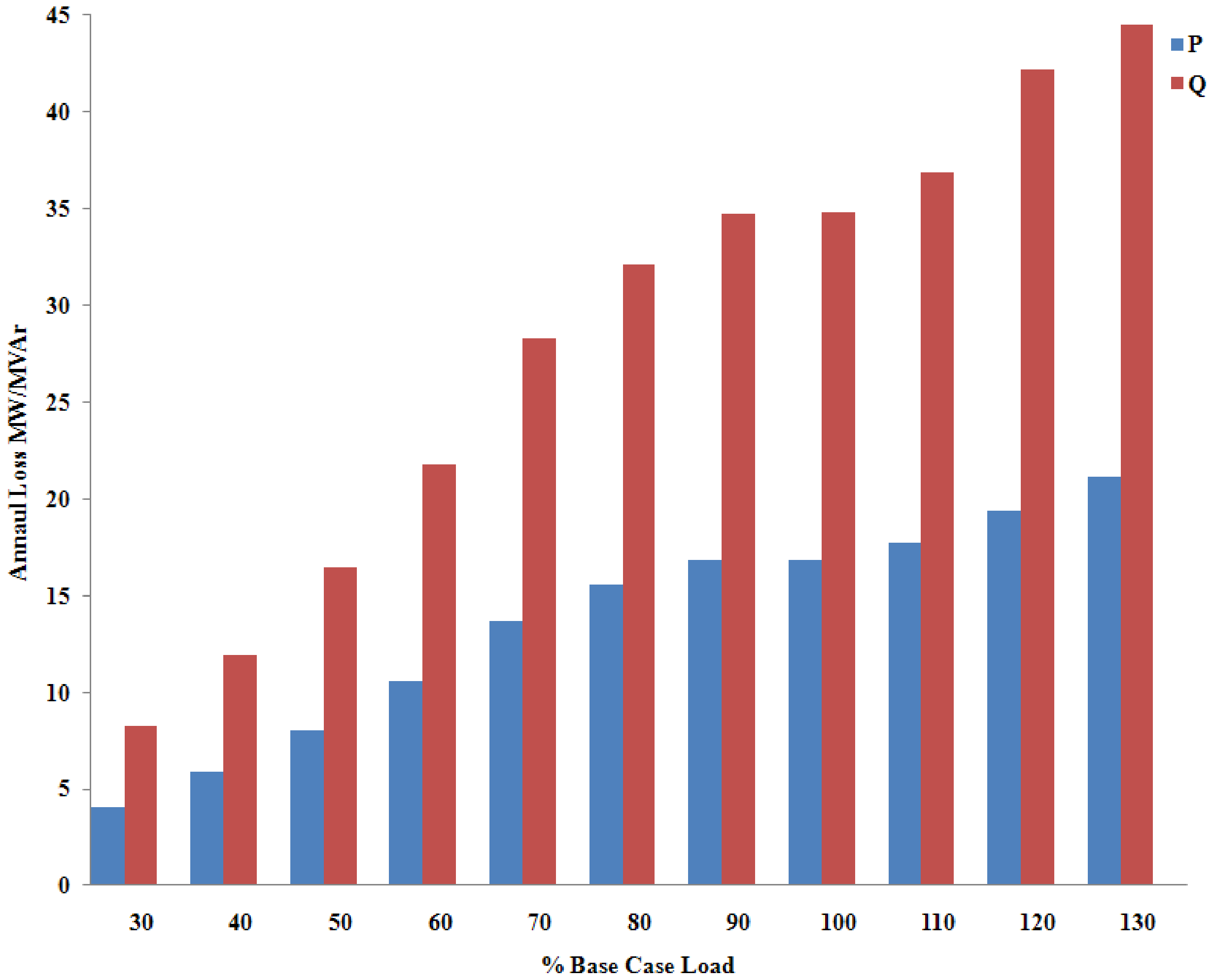

Fig 1.32 Annual power Losses for different base case loads

The losses associated with the operation of Diesel, PV, and Wind combination at different base loads is presented in Fig 1.32. The results show a linear increase in power losses when the base case total load is increased from 30% to 90%. At 100% of the base case load or the load for which the network normally operates under healthy operating conditions, the power losses are slightly less than that of 90% of the base case load. Although the power losses are less at 100% of the base case as shown in Fig 1.32, the most economical generating unit combinations were found at 90% base case load that incorporates cost function of power losses (Fig 1.25). If only the power losses are taken in to account, the generating unit combination associated with 30% base case load would have been selected as the optimal unit configuration because it has the lowest total power losses for the year.

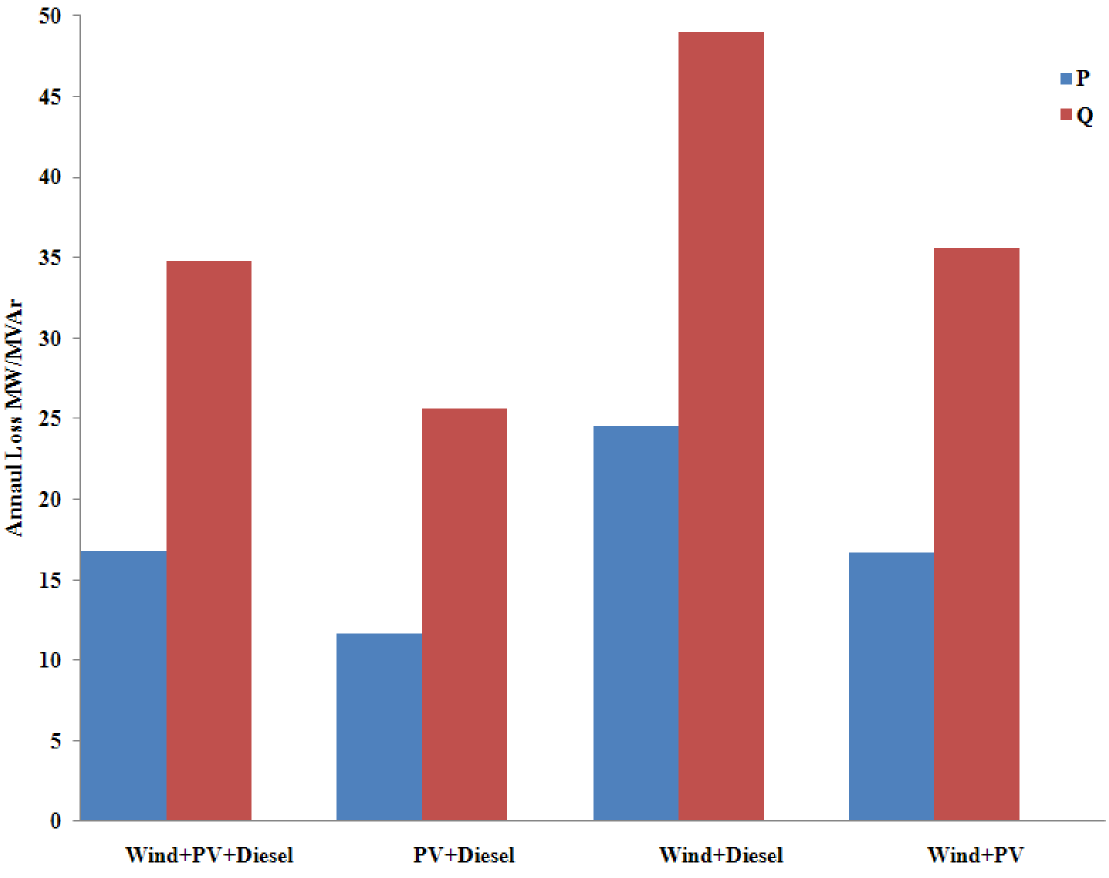

Fig 1.33 Annual losses for different DG combinations

Fig 1.33 shows the power losses for different combinations of generating units. The research finds that the most economical combination of wind and diesel is not the best choice when only the power losses are taken into account, while PV and diesel appear to be the best combination with regards to power losses. This discrepancy between the two sets of results is associated with the locations of the wind and PV systems with regards to the loads. When PV is supplying the loads with diesel and the grid, the major part of the load which is in Zone B is supplied by grid, which is situated at the optimal location of Zone B loads. However wind and diesel combinations do not follow this argument, hence the associated power losses are larger.

The above arguments show that how the decisions can be vulnerable to errors if the detailed assessment approach as presented in this report is not taken into account for the selection of optimal generating unit combinations and their performance in a distribution network.

1.7 Conclusions

The software program was developed and scripted using 'IPLAN' interactive programming language to work in conjunction with PSS/E software. The algorithms corresponding to the software development is presented in this report.

Set of scenarios are developed and investigated the most economical combinations of hybrid generating units, their performance, and individual merits with regard to objectives of this part of the project. The results suggest that the best possible combinations of various DG's such as wind and PV systems that can be operated with critical supports of diesel units as supplement to the grid power supply.

The investigations further suggest that the Wind and Diesel generating unit combination gives the most economical power generation for the particular network that is considered for the assessment. Then, Wind, PV, and Diesel followed by PV and diesel combinations.

With regard to the case studies, the week 47 provides the most critical operating condition to determine the entire year feasibility of the generating unit combination. It further suggests that the identification of such critical operating conditions enable to reduce number of steps that are required to process the algorithm and reduced processing time of the algorithm.

The case studies presented in this report are referring to constant cost factors of generating technologies and assets. However, the software program is developed to incorporate varying costs of generating technologies and assets that may be arisen through the inflation and life cycle effects. Such facilities in the software enables to incorporate varying cost components of PV, Wind etc as well as the futuristic cost elements that may be arisen through subsidies provided by governments for the use of particular generating technologies.

Even though the costs of operation of the renewable energy technologies are minimal, the integration of large volumes of wind turbine units may not always be economical because of the high capital costs seen today. On the other hand, the increased integration of wind power into distribution networks can affect the value of utilisation of wind power generation in monetary terms however it may positively benefit the environmental concerns. This can be justified from the results presented through case studies. During the week 5 of the base case load scenario in Fig 1.14, the installed capacity of wind power generation is very high, when compared to diesel and PV, however this combination was found to be economically infeasible when the full year run was performed.

The Fig 1.15 to Fig 1.24 suggests that variation in the load level does not affect best possible combination of the hybrid energy technology of the particular network considered for the assessment. The variation would only affect the installed capacity of the generating technology in a proportionate rate leaving the unit combination unaffected.

The use of various types of costing details such as operating cost, maintenance cost, capital cost etc is pivotal in arriving at the final conclusion in determining most economical generating unit combination. The effects of exclusion of some of the costing factors are critically analysed and presented in Fig 1.26 to Fig 1.28. On removing the capital cost factors from the algorithm, the output of the assessment was more wind and PV generation biased.

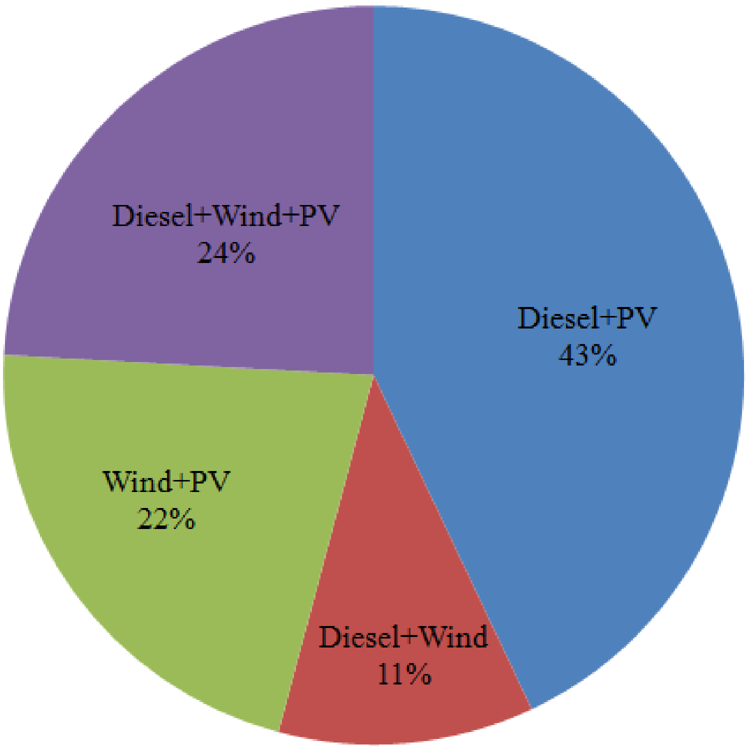

Fig 1.34 Cost –benefit analysis with different DG technologies

The pie-chart presented in Fig 1.34 represents the variation in overall costs associated with the power distribution system when different types of generation technologies were utilized to supply the load demand. The most economic combination was found to be that of a hybrid system incorporating Diesel and Wind combination, which was found to be around 13%

cheaper than when the combination of Diesel, Wind, and PV was utilised. The results further suggest that the wind-diesel operation is 32% economical than that of PV-Diesel operation for the same network condition.

1.8 References

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