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Optimizing distributed generation parameters through economic feasibility assessment

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Abstract
To meet the fast growth of electricity demand, the traditional network solution tends to expand existing substations, build more new substations, and build transmission lines. Distributed Generation (DG) is posed as an alternative method for the network providers not only to accommodate the load increase and relieve network overload, but also to offer other additional technical and economic benefits. This paper addresses the issue of DG planning and has proposed a technique for optimizing the DG size and location to minimize the overall investment and operational cost of the system. The proposed optimization methodology assesses the compatibility of different generation schemes in terms of their cost factors that can be significantly contributed by a DG. The direct and indirect costs of power supply quality, reliability, energy loss, total power operation, and DG investment are used as key cost components of the DG siting and sizing strategy. The Particle Swarm Optimization (PSO) method is applied to obtain the optimal DG planning solutions. Finally, the proposed approach is tested on a distribution feeder of an Australian power network. Simulation results are presented to illustrate the feasibility and effectiveness of the proposed method.

Keywords
assessment, parameters, feasibility, optimizing, distributed, economic, generation

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Optimizing Distributed Generation Parameters through Economic Feasibility Assessment

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\textit{Abstract} — To meet the fast growth of electricity demand, the traditional network solution tends to expand existing substations, build more new substations, and build transmission lines. Distributed Generation (DG) is posed as an alternative method for the network providers not only to accommodate the load increase and relieve network overload, but also to offer other additional technical and economic benefits. This paper addresses the issue of DG planning and has proposed a technique for optimizing the DG size and location to minimize the overall investment and operational cost of the system. The proposed optimization methodology assesses the compatibility of different generation schemes in terms of their cost factors that can be significantly contributed by a DG. The direct and indirect costs of power supply quality, reliability, energy loss, total power operation, and DG investment are used as key cost components of the DG siting and sizing strategy. The Particle Swarm Optimization (PSO) method is applied to obtain the optimal DG planning solutions. Finally, the proposed approach is tested on a distribution feeder of an Australian power network. Simulation results are presented to illustrate the feasibility and effectiveness of the proposed method.
Keywords— Distributed Generation, Optimal Placement, Optimal Size, Supply Quality, Supply Reliability, Energy Losses.

I. INTRODUCTION

In recent years, Distributed Generations (DGs) play an important role in the operation of distribution networks to cope with environmental and economic issues raised by conventional large power plants. Also, both system security and reliability, especially in distribution networks, are becoming critical because of the growth in the power demand, the difficulties of building new power plants, and in expanding network capacity [1]. Recently, these obstacles together with strong encouragement to reduce emissions have been main drivers for distribution network planners to explore the economic and technical potentials of small generators, known as Distributed Generation (DG) units. DGs are defined as small-scale generating units placed close to the loads that are being served; they have variety of size from a few KWs to MWs and include two general classifications: non-renewable (like combustion gas turbines, micro-turbines, fuel cells, and micro-Combined Heat and Power (CHP) plants) and renewable energy resources (wind turbines, photovoltaic, full-cells, biomass, micro hydro turbines, etc.) [2]. A number of alternative DG technologies, such as fuel cells, storage devices, photovoltaic, and wind turbine are now approaching commercial economic viability. Moreover, conventional small generation technologies such as diesel generator and gas turbine can offer improved performance and flexibility for the distribution systems [3].

Connection of DGs fundamentally alters distribution network operation and can creates a variety of well-documented impacts: (a) reducing any penalty/payment or negative impact towards the supply quality and outages, (b) reduction of the “payment” related to grid energy losses, (c) reduction of electricity delivery cost by serving loads locally, (d) reducing the required reserve margins and increasing the energy efficiency, therefore, reduction of the capital and operation costs in some cases, and (e) reducing or deferring upgrading costs for transmission and distribution facilities. Moreover, from the customer’s point of view, DG may (a) provide customers with an alternative electricity sources, (b) utilize heat, waste, or by-products from other processes if available to produce electricity, (c) reduce the electricity bills, especially in case of small and remote customers, (d) improve the power supply quality, security and reliability, and (e) reduce the amount of emissions. Subsequently, these benefits make it possible to consider DGs as a promising alternative of conventional power plants to provide electricity demand growth. In the other hand, an inappropriate sharing and operations of these resources may lead to reverse outcomes like power quality issues, high amount of losses, voltage rise, and
system instability [4, 5]. Indeed, the power quality of the customers is related to the quality of voltage at buses. For instance, installing DGs can boost or decline the voltage quality based on the power factor situation (lead, lag, or unity) [3]. Also, recent changes in the operation of distribution networks that enable active networks by installing DGs can lead to an increased short-circuit currents in the network apparatuses such as switchgears with lower short-circuit current levels [3]. It is evident that the placement and sizing of DGs play a significant role in the operation as well as power quality and reliability of distribution systems. Therefore, to ensure the satisfactory performance of distribution networks, it is vital to include these concerns in the placement and sizing of DGs.

DG placement and sizing by considering various technical concerns has been discussed considerably over the last decade. Indeed, this problem has been solved from different point of views. From the utilities’ standpoint, DG placement problem can be modelled while considering economic objectives as well as multiple technical issues such as loss reduction, voltage profile improvement, voltage stability enhancement, network upgrade deferral, and reliability [6–12]. Also, a number of studies have been proposed in the literature to assess the compatibility of different DG planning schemes. Authors of [13] have developed an optimization model for DG siting and sizing, aiming to reduce the energy costs as well as the minimization of environmental impact in terms of CO₂ emissions. Reference [14] introduces analytical expressions to determine the optimum sizes and operating strategy of DG units considering the DG impacts on power loss minimization in the system by involving time-varying demand and possible operating conditions of DG units. An Improved Analytical (IA) method has been developed in [15], to solve the problem of accommodating different DG types into the large-scale primary distribution networks for achieving a high loss reduction. In [16], a multi-objective Chaotic Improved Honey Bee Mating Optimization (CIHBMO) was proposed to daily Volt/VAr control in distribution systems including DGs, considering objective functions counting costs of energy generation by DGs and distribution companies, electrical energy losses and the voltage deviations for the next day. Authors in [17] solved a DG placement problem, based on voltage stability analysis as a security measure. Modal analysis and continuous power flow have been used in a hierarchical placement algorithm in [17]. In [18], the DG sizing and siting have been obtained by a heuristic cost-benefit analysis based approach, with the objectives of maximizing the revenue from selling of electricity and minimizing the cost from the DG investment and operation. An overview of the state of the art on the models and methods applied to the optimal DG placement problem, and analysis and classification of the current and future research trends in this field has been presented in [19]. Also, the numerous strategies and techniques that have been developed in recent years to address DG integration and planning can be found in [20]. As well, a planning scheme has been presented in [21] for PV integration with the
objectives of reducing the cost of installation, operation and maintenance as well as the energy imported from the grid side. Also, analytical approaches have been proposed to find the location, size and power factor of DG using dual indices including minimizing power losses and the enhancement of loadability and voltage stability [22, 23]. In [24], a multi-objective expansion planning of distribution networks have been presented in the presence of DGs.

In Australia, Distribution Network Operators (DNOs) have been separated from the retail markets recently and hence do not have direct contact with the customers. However, they are able to own DG units under the current framework of Australian Electricity Regulator (AER) and freely decide to install the DG in the networks and can control the DG units owned by them. This paper addresses the issues and concerns of the utilities regarding the DG inclusion in the networks. One of the main challenges of utilities is to evaluate the network power quality as well as system reliability in the presence of DGs. To cope with this issue, it is desirable to develop a procedure to include the system performance index regarding power quality and reliability when DGs are located. As above mentioned in [6-24], while the optimal design and operation problem of DGs has motivated much research in the last decade, few existing tools seem to offer the evaluating tool required by utilities for financial aggregated assessment of reliability and power quality in the distribution networks in the presence of DGs. The majority of current approaches is often strongly focused to a specific project and necessitates extensive reformulation in the event of the future modifications, such as changes in DG technology options and price structures. In this regard, when a utility has made a conclusion to install a DG, decisions have to be made regarding the DG size and its location. This paper presents a methodology for optimizing a utility-owned DG size and location on the basis of economic considerations under existing loading patterns. DG is considered as voltage regulation equipment and also a back-up generation to enhance supply reliability, and to reduce energy losses in the distribution network as well. From this perspective, different DG schemes are available that can be compared on the basis of their direct or surrogate financial performance in terms of voltage quality and reliability costs, energy losses and DG capital investment cost and power operation cost. Indeed, recently, a few studies have presented DG allocation while considering the optimal performance of the network, in which the power quality and reliability of the network are optimized simultaneously. Accordingly, to the best of our knowledge, the new contributions of this paper with respect to the previous ones, e.g., [6-24], can be summarized as follows:

- Presenting a new DG placement framework, where, the most important issues in the distribution network such as losses, voltage regulation, and reliability have been incorporated in a unique cost-based function.
- Modeling the DG as the voltage regulation equipment, with an Advanced Line Drop Compensator (ALDC) and a proportional controller.
- Application to a real case example, with the practical assumptions.

The remaining parts of the paper have been organized as follows. In Section II, the problem statement is briefly reviewed. In Section III, the proposed approach for optimal placement of DG is formulated. In Section IV, a distribution system extracted from the Tasmanian power system as a test system has been illustrated and its main features have been outlined. Numerical results obtained from implementing the proposed method on the test system, are presented in Section V. Section VI concludes the paper.

II. PROBLEM STATEMENT

DG units can be installed in the distribution system either by the utilities or by individual customers. DG units that belong to the end users are usually designed with definite sizes by the owners, and are located usually at their own locations. On the other hand, the utility owned DG units could be located at a much wider range of locations. Also, their sizes could vary widely from a few kWs to a few MWs, and this is only governed by the maximum permitted penetration level of the connected DG units into the system. It is worth to mention that the maximum penetration of DG is limited by thermal and voltage constraints of the network. In fact, installation of a distributed generator in the network may cause over voltages, particularly in the vicinity of DG connection point. In addition, line losses will restrict the DG penetration.

This paper considers only the implementation of utility-operated DG units. As a result, utilities need to know the best possible options for introducing DG into their networks. They also need to know the strategies how to select the most suitable DG size and location to assist the system to meet technical requirements and to minimize the total costs. The cost minimization addressed in this paper belongs to one of the two possible classes:
- DG units driven by some specific renewable energy sources (such as wind and solar) are to be sited near to a particular type of resources. Therefore, their locations are predefined and only their sizes need to be optimized.
- For DG units driven by less site-specific-renewable energy (e.g. biodiesel and fuel cells) and non-renewable resources (such as diesel and gas), both the DG size and its location are subject of the optimization.

As the capital investment and operating costs of DG are usually substantial, they require careful assessment before implementation. Based on the factors discussed above, an optimization approach has been developed in this paper to evaluate the economic feasibility of the best selection of DG installation.
III. PROBLEM FORMULATION AND SOLUTION

This section is divided into three parts. The first and second parts describe the two phases of the proposed approach: (A) developing the objective function; (B) selecting an optimization algorithm to determine the best DG solution that provides the minimum value of the objective function; and the last part (C) demonstrates how the approach could be applied to determine an optimal DG plan through economic assessment.

A. Objective function

The total costs incurred by a distribution utility, represented by the performance index (PI) in this paper, consist of two main elements: the initial capital investment, and the annual operating cost. The first cost includes the cost of equipment, installation, and other auxiliary costs that are spent during the implementation of the DG. The second cost contains the costs associated with generating power and DG maintenance costs as well as penalties for voltage violation, energy losses, and loss of loads.

In this paper, an objective function is formulated based on the following assumptions:
- The cost of the DG installation depends on both location and size of DG. But, it is assumed here that every location has the same cost for the DG units to be installed, and this cost only depends on the DG size.
- Many of the energy sources have a fuel cost and it is assumed here that efficiency is constant so that fuel cost is proportional to the amount of kWh generated. This cost can be calculated as:

\[ \text{Cost of DG operation} = \sum \text{kWh operation} \times \text{rate}^{op} \]  

where, \( \text{rate}^{op} \) is the cost associated with the energy generated by the DG in dollars per kWh of DG output.
- The DG maintenance is expressed as an annual cost, which is dependent of the DG size and its life cycle.
- Calculation of equivalent costs of voltage quality, supply reliability, and distribution energy losses is more complex and is discussed in the later part of this section.

Meeting upper and lower voltage constraints is a critical component of the distribution system design [25]. According to the regulatory standards, voltages at the customer site have to be maintained within specified limits (1.0 ± 0.05 p.u.), and there are some consequences for utilities failing to meet the standards. In this paper, we consider the DG as an alternative mean to meet the voltage requirements and thus we consider a penalty on the voltage excursion. This is to ensure that there is a priority, to some extent, for the system to operate such that the regulatory requirement could be achieved. The voltage quality in the system is proposed to be evaluated by System Under-specification Duration Index (SUDI). The index defines the duration when the supplied voltage is
below the specification for customers served during a specified time period. SUDI is calculated by taking the sum of customer-minutes under voltage violation during a certain period of time, as follows:

$$SUDI = \sum_{i=1}^{TU} N_i^U \times t_i^U$$  \hspace{1cm} (2)$$

where, $N_i^U$ is the number of under-threshold customers connected to bus $i$, and $t_i^U$ is the duration of bus $i$ suffered from voltage violation throughout the examined period. Also, $TU$ is the total number of under-threshold buses.

In order to convert the SUDI into the cost function, it is multiplied by the rate of payment toward one customer-minute suffered from voltage-under-threshold. This rate of penalty may vary from one customer to another, depending on their importance. Therefore, the cost of voltage quality can be computed as,

$$Cost\ of\ Voltage\ Quality = \sum_{i=1}^{TU} N_i^U \times t_i^U \times rate_{i}^{SO}$$  \hspace{1cm} (3)$$

where, $rate_{i}^{SO}$ is the cost for bus $i$, in dollar per customer-minute, associated with the voltage violation.

The supply reliability cost is evaluated based on the System Interruption Duration Index (SIDI). The index defines the duration of interrupted power supply for customers served during a specified time period. SIDI is calculated by taking the summation of customer-minutes outage under interruption events during a certain period of time, as given in (4).

$$SIDI = \sum_{j=1}^{E} \sum_{i=1}^{TI} N_{ji}^I \times t_{ji}^I$$  \hspace{1cm} (4)$$

where, $N_{ji}^I$ is the number of interrupted customers connected to bus $i$ during the interruption event $j$, and $t_{ji}^I$ is the interrupted duration of bus $i$ during the interruption event $j$. Also, $TI$ is total number of interrupted buses during interruption event $j$, and $E$ is total number of the interruption events throughout the examined period.

The dollar penalties regarding to loss of supply is calculated by multiplying the SIDI by the rate of payment for one customer-minute outage, as in (5).

$$Cost\ of\ Supply\ Reliability = \sum_{j=1}^{E} \sum_{i=1}^{TI} N_{ji}^I \times t_{ji}^I \times rate_{ji}^{SR}$$  \hspace{1cm} (5)$$

where, unit of $rate_{ji}^{SR}$ is the cost for bus $i$, in dollar per customer-minute, associated with the interruption event $j$.

It is not common for utilities to have actual payments associated with the voltage errors or reliability. The equivalent cost is a mean of expressing the desirability of improvements in these customer related aspects.

Finally, the cost of energy losses is calculated as:
\[ \text{Cost of Energy Losses} = \sum_{e=1}^{n_{br}} |I_e|^2 \times r_e \times g_e \times \text{rate}^{EL}. \]  

(6)

where, \( n_{br} \) is total number of branches in the system, \( |I_e| \) is the magnitude of current flow in branch \( e \), \( r_e \) is the resistance of branch \( e \), \( g_e \) is the time duration in which line losses exist, and \( \text{rate}^{EL} \) is the cost associated with the energy losses, in dollar per kWh.

Once the DG is connected to the system, its operation will affect the economic benefits of the distribution company throughout its life cycle, say NY-years. The equivalent expenses of the system paid by utility in NY-year time, which are expressed as the PI, are actually the present value compounding with discount rate. The present value of annual cost can be expressed as [26]:

\[
PV = AC \left( \frac{1}{1 + dr} + \frac{1}{(1 + dr)^2} + \ldots + \frac{1}{(1 + dr)^n} \right) = AC \frac{(1 + dr)^n - 1}{dr(1 + dr)^n}.
\]

(7)

where, \( PV \) and \( AC \) are the present value and annual costs, respectively. \( dr \) is the discount rate at which the amount will be compounded each period (per annum in this case), and \( n \) is the number of periods. Thus, the performance index (PI) is calculated as follows:

\[
\text{PI} = \left[ \sum_{i=1}^{W} \left( \sum_{j=1}^{V} \left( I_{ij} \times \text{rate}_{ij}^{E&I} \right) + \sum_{j=1}^{V} \left( I_{ij} \times \text{rate}_{ij}^{M} \right) \right) + \sum_{j=1}^{V} \left( I_{ej} \times \text{rate}_{ej}^{EL} \right) + OP_{an} + MT_{an} \right] \times \frac{(1 + dr)^n - 1}{dr(1 + dr)^n} + EI.
\]

(8)

Where, \( EI \) is the capital investment cost of the DG equipment and installation (E&I), and is calculated as:

\[
\text{E&I cost} = k \times \sqrt{\text{DG size}}.
\]

(9)

Note that, equation (9) is an empirical formula. This formulation is established based on the data gathered by the utility on DG investment. This can be different for various types of DGs. This indicates that, in practice, the larger the size of the DG installed, the smaller the increment rate of the E&I. In equation (8), \( MT_{an} \) is the annual maintenance cost of DG. Also \( OP_{an} \) is the annual cost associated with the total power operation of the network (includes substation cost and DG operation cost).

The DG size and location problem can be formulated as an optimization problem with the objective function as in (8).
B. Optimization algorithm

The Particle Swarm Optimization (PSO), which is a well-known and suitable algorithm for problems with multi-constraints, is applied to obtain the optimal DG planning solution. The PSO technique can generate an acceptable quality solution and stable convergence characteristics during a short calculation time than other stochastic methods [27]. Unlike the others, the PSO has a flexible mechanism to improve the global and local exploration abilities.

As mentioned earlier, two cases of DGs are considered: the first case is the site-specified DG and the second is the non site-specified DG. In the first case, the decision variable \( \text{DG}_\text{para} \) is an array of single dimensions of the DG size (\( \text{DG}_\text{para} = [\text{DG}_\text{size}] \)), and in the second case, the decision variable \( \text{DG}_\text{para} \) is an array of two dimensions of the DG size and DG location (\( \text{DG}_\text{para} = [\text{DG}_\text{size}; \text{DG}_\text{loc}] \)). The PSO algorithm is used to determine these variables, such that: \( P1 (\text{DG}_\text{para}) \) is minimized.

C. Implementation

The implementation of the optimization of the DG parameters is demonstrated on a simple system shown in Fig. 1. The system has a single lateral attached to it.

Calculations are performed for a one-year load cycle. In our study, for the sake of simplicity, it is assumed that the loads do not change significantly within 15 minutes intervals. Thus, we consider variations of load curves in time steps of 15 minutes for every single node in the network. However, the time step is treated as a variable so that it can be assigned by the user. In this study, the loads are measured and analysed every 15 minutes, as per the procedures given in Fig. 2 and Fig. 3 to determine the relevant DG output, the total number of customers experiencing the voltage violation, the energy losses, and the total number of customers subjected to the outage. The costs of voltage quality, power operation, energy losses, and supply reliability are calculated as the procedure proposed in Section III-A.
The flowchart given in Fig. 2 is explained as follows. At time $i$, the load measurements are taken place. The local voltage and current values at the DG connection point are obtained. These values are then supplied to the DG controller to calculate the suitable DG output. In this study, the DG controller is modelled with an Advanced...
Line Drop Compensator (ALDC) and a proportional controller. As the DG is designed for looking after the weakest voltage point in the system (normally at the far end of the feeder), it is required to obtain a proper voltage prediction at the downstream of the feeder. The ALDC predicts remote end voltage by using the local voltage and current measurements. The ALDC works based on this assumption that the line current drops linearly from the measurement point to the end of the feeder. Thus, at a point $x$ (which is a distance) from the substation, the estimated current can be written as:

$$I(x) = I_d - \frac{x-d}{l-d}I_d$$

(10)

where, $l$ and $d$ are the distances from the remote end and regulation point to the substation, respectively, and $I_d$ is the measured current at the regulation point.

The voltage prediction $V_{pr}$ at the point of load, which is $f$ (km) far from the substation, can be determined by subtracting the estimated voltage drop from the local voltage at DG point $d$, as in (11).

$$V_{pr}=V_d - \int_{x=d}^{f} zI(x)$$

(11)

where, $V_d$ is the local voltage at $d$, and $z$ is the line impedance per unit of length. It should also be noted that if the load is roughly uniformly distributed, the ALDC can be applied to predict the system voltage. If other information about customer’s load such as composite billing data is available, modification of the ALDC will provide more accurate results. Next, the error of the system voltage compared to the reference level, $\Delta V$, is calculated.

$\Delta V$ is defined as the difference in magnitude between the voltage prediction made by the ALDC ($V_{pr}$) and the reference voltage of DG controller ($V_r$) and expressed as below:

$$\Delta V = |V_{pr}| - |V_r|$$

(12)

Reference voltage is chosen as the lower voltage limit plus some level of the tolerance.

Then, the DG, based on this error, will adjust its output current to correct the system voltage using the proportional controller:

$$M = K_p \Delta V$$

(13)

where, $K_p$ is the proportional constant.

Note that the constant of the controllers as well as the voltage reference value should be adjusted such that a reasonable voltage support can be provided by the DG. The minimum reference voltage is suggested to use for
obtaining a cost-effective solution. However, it is possible to raise the voltage level above the required minimum. If the reference voltage is higher than the lower limit or the required minimum, a larger size of the DG will be required which may result to an expensive solution. In a radial system, the remote end voltage is usually close to the lower limit due to the voltage drop throughout the feeder. To increase this to the level of the upper voltage limit, a significant investment in DG system will be required. It is worth to note that the proposed solution methodology is flexible to set a user-defined value for the required reference to achieve the target of the voltage support. The actual DG output is influenced by the probability of the DG failure. If the DG fails at time \( t \), DG output will be zero. Otherwise, it will generate the desired output, \( M \). Then, the power flow analysis is performed. The same process is repeated until the DG controller becomes stable, which means that the difference between output values obtained in current iteration \( j \) and previous iteration \( (j-1) \) is less than a tolerance of \( 10^{-4} \). The value \( 10^{-4} \) represents the DG controller sensitivity, and can be assigned by the user.

Fig. 3 shows the algorithm to determine the total outage in MW with respect to a single line fault at a specified line section \( k \) on the feeder. The term “line section” represents a portion of the feeder, which is faulty and can be separated from the rest of the system using proper protection devices. Fig. 3 reveals that, when a fault occurs, protection system acts as follows: automatic/manual switching to disconnect the faulty section from the main grid, restoration process, and automatic/manual switching to reconnect the feeder to the main grid. At every step of the protection actions, the number of island(s) formed is determined. We define that an island is able to operate only if there is no line failure and at least one DG is able to generate electricity in that island. According to the number of customers that can be supplied by the main grid as well as by the DG system(s) in the island(s), we can compute the number of customers suffering from the electricity outage. The cost of supply reliability is computed using the technique discussed in Section III-A.

Next, calculation of one-year cost data is performed by summing up all the cost values associated with each load measurement over the yearly pattern. Long term planning costs can be obtained by converting the payment of each year (or each \( N \)-years in the case of the equipment and installation cost of DG) compounded by the annual discount rate into the Net Present Value (NTV). Based on the cost analysis, we can determine the performance index (PI) proposed earlier.

In the proposed framework, decision variables, objective function, and constraints are clearly defined. The PSO technique is used to obtain the optimum value. Note that, the planning procedure (include the analyses of DG operation, voltage quality, energy losses, and supply reliability) are solved for all the populations and iterations of the PSO algorithm. In order that the optimization would converge more quickly, the optimal
solutions for the system shown in Fig. 1 can be obtained through two independent searches. The first search is made for the DG located on the main feeder only, while the second search is made on the lateral. The values of the objective function for these two sets of solutions are then compared and the lower cost solution is selected. If the system has more than one lateral, a similar process is applied to each lateral.

Furthermore, the proposed methodology can be applied for more complex systems (i.e. with non-uniformly distributed loads, transformer, regulator, etc.) by including their effects in the admittance matrix when performing the network analysis.

IV. TEST SYSTEM

A distribution system extracted from the Tasmanian power system in Australia is shown in Fig. 4. This system has a 48-km radial feeder connected between Smithton substation and Woolnorth, which belongs to the Tasmanian Distribution Company, known as Aurora Energy. Nominal voltage at the substation $V_S$ is 22 kV and Thevenin equivalent source impedance is $(0.7278 + j2.6802) \, \Omega$. It is assumed that the loads are uniformly distributed on the main feeder and nine laterals with different levels of load distribution. Line impedance for the main feeder is $Z_{\text{line-main}} = (0.6672 + j0.3745) \, \Omega/km$ and for the laterals is $Z_{\text{line-lateral}} = (0.5959 + j0.3345) \, \Omega/km$. The main feeder has a total of 69 load buses in which bus 1 is closed to the substation and bus 69 is at the remote end.

The protection devices of the test system include one automatic circuit breaker between bus 1 and bus 2, and one automatic recloser between buses 34 and 35 on the main feeder. Also, there are two manual air-break switches at two ends of each line section. This is to ensure that the faulty section will be disconnected from the rest of the system in the case of failure.

The procedure which has been used to produce feeder load data for the test system is given in Fig. 5. Typical daily load data is adapted from [28]. In this case study, it is assumed that the percentages of residential, commercial and industrial loads are 70%, 20% and 10%, respectively. Also the maximum load is 1.65 MW for this rural network and it varies at different days of the week. The maximum load during the weekend is lower than the maximum load in weekdays. This is due to the fact that most industrial loads and a large part of residential and commercial loads are not switched on during the weekends. Random factors are also added to the base load to produce different load patterns for different days during the week. The daily load variation of the feeder is assumed to be within $\pm 5\%$ of the typical load. The weekly load curve from Monday to Sunday is shown in Fig.6.
Fig. 4: Smithton – Woolnorth test feeder.

Fig. 5: Daily load estimation procedure

Fig. 6: Typical weekly load curve
The load is also affected by seasonal changes of the temperature. Temperature in a day alters the load level as people tend to use heaters in the cold days and air conditioners or fans in the hot days. Thus, more loads are connected to the main grid either when the temperature rises too high or drops too low. For this reason, it can be assumed that the increment of load during hot weather is defined based on the daily high temperature, while during cold weather it is calculated according to the daily low temperature. The additional loads due to the seasonal factor are computed in term of the percentage of the base load. It is assumed that, if the lowest temperature of the day is lower than 50°F or the highest temperature of the day is higher than 69.8°F, the load will increase. However, in our study, different rates of the load increase are applied to demonstrate the different tendencies of the load rise during the summer and winter periods.

The daily peak load over a year is shown in Fig. 7. As can be seen, the system load is lower during autumn and spring, higher in summer and reaches its peak value in the winter time. The load curve also reveals specific Tasmanian load characteristics with the significant number of heating loads compared to the air-conditioners and fans. This results in the peak load in winter considerably higher than the peak load in summer. Where specific measurements of load are available, this would be preferred to this load synthesis.

![Load Synthesis](image)

**Fig. 7: Daily peak load in a year**

V. **RESULTS AND DISCUSSIONS**

Simulations are carried out based on the following assumptions:
- DG is being operated at unity power factor.
- The start-stop cost of DG is ignored.
- The probability of a successful starting of the DG is 90%. In other words, every time a DG unit is switched on, the probability that it fails to start is 10%.
− Once the DG fails to operate, it takes from one hour to 24 hours to repair it.

− The line fault probability is 1 fault/km/year. The ratio of the permanent faults to transient faults is 1 : 5. This ratio is typical for Tasmania and is taken on an advice of Aurora Energy experts (Aurora Energy is a Distribution Utility in Tasmania, Australia). The permanent fault requires 3 hours for repair, while transient fault is automatically cleared by a successful recloser.

− Operation times of the circuit breaker, recloser and air switch are 2, 7, and 10 seconds, respectively. However, the air switch requires a manual operation. A technical staff member has to travel to the air switch location and manually open or close the switch. In this study, the speed of travel is assumed to be 70 km/hr.

− Once an island is formed, a control system is activated to control the voltage and frequency of the island.

− Loads have automatic frequency load shedding devices.

− The DG life expectancy is 10 years. In other words, after 10 years of the DG operation, renovation of the facilities is required.

− To solve the optimization process using PSO, the number of populations and iterations required are found to be 500 and 100, respectively.

Also, it should be noted that, if the DG penetration is low, DG implementation can be carried out without explicit consideration of the protection system. However, in the case there is need for high DG penetration, the protection system must be revisited.

The penalty used for each customer-minute under voltage specification is $1 on the basis of 69 customer points. The reliability cost varies widely with respect to the customer type, depending on the load priority and the contract agreement between the electricity supplier and the customer [29]. In our simulation, it is assumed that the cost paid by the utility for 1 MWh outage varies from $0 to $10,000. The cost of 1 MWh transmission line losses is $25.

In equation (9), DG_size is expressed in kW and $ is $3,000, a typical value used for diesel type of DG. The initial investment of the DG versus the DG size is shown in Fig. 8.

The electricity price of the substation is changed from 5 to 10 cents/kWh. The DG operating cost is of 30 cents/kWh, while the annual DG maintenance cost is 20% of the E&I cost. The discount rate is assumed to be 7% per annum.

Two nominal loading levels, which are 1.046 MW and 1.148 MW on the average, are considered in the simulation and their optimal results are examined to observe the effect of the load growth. Fig. 9 shows the DG
output compared to the load level in one week for the two load levels. From Fig. 9, it can be seen that DG operates in a reasonable manner to contribute to the peak-time power demand of the network. It is only turned on when the load is considerably high, and remains off-line for the rest of the time. The output levels of the DG shown in Fig. 9 prove that, with the current settings of voltage reference and constant for the DG controller, the DG is running only when the voltage at remote end is lower than the reference voltage, and therefore will not lead to a significant increase in operating cost.

![Fig. 8: DG capital cost versus DG size](image)

![Fig. 9: DG weekly output with the average load (a) 1.046 MW, (b) 1.148 MW](image)

Now, we consider the case for the site-specified DG. Let us assume that the DG is located at the remote end on the main feeder (which may be close to the energy resource). Also, for this scenario, the reliability penalty used is $10,000/MWh for the loss of load. By using the proposed approach, we found that when a DG rated at 84% penetration is applied in the system (for both load scenarios), the total payment from the utility is found to be the lowest. Note that the term “penetration” used here actually represents the ratio of the DG size to the maximum load level. The maximum load levels are found to be 1.65 MW and 1.81 MW for two nominal loading levels mentioned above, respectively.
In order to see how each component of the performance index (PI) contributes to the total cost and how they vary with the DG size, the following studies have been carried out. Figs. 10 and 11 show the utility’s weekly expenses related to the voltage quality, reliability, energy losses, and DG capital, operating and maintenance costs, with respect to the DG size for two loading scenarios. The cost of quality, in both cases, reveals that when the DG size reaches a certain level, the DG controller is able to totally eliminate the voltage violation problem in the system. Thus, it reduces the cost of quality to $0 in this case. The DG size level is about 2% penetration for 1.046 MW nominal loading and 6% for 1.148 MW nominal loading. In other words, when DG is big enough and an effective voltage control system is used, it is possible to maintain voltage at the customer site within the specified limits.

The cost associated with energy losses can be considered relatively small. It can be seen that as the DG size increases, the energy losses reduce to a constant value. As can be seen, further increase in the DG size does not have any effect upon the transmission line losses anymore. This is the consequence of the fact that the DG controller is designed to maintain the feeder voltage within the specified limits. Therefore, the maximum DG output, in term of kWh, will be at the level at which all customers are within specified voltage limits.

Fig. 10: System expenses with the average load = 1.046 MW

Fig. 11: System expenses with the average load = 1.148 MW
Note that, in the case with 1.148 MW nominal loading, both costs associated with voltage quality and energy losses have remained unchanged for DG penetration higher than 6%. However, in the case with 1.046 MW nominal loading, the cost of voltage quality has been zero in the DG penetration of 2%, but the cost of energy losses has remained unchanged in 5%. This is because the voltage reference and constant for the DG controller have been set for the higher loading level (i.e. 1.148 MW nominal loading). The main contributions to the total utility expenses are made by the reliability cost and the DG cost. Simulation results show that the reliability cost decreases as the DG size increases. This outcome is quite obvious since the bigger the DG size, the more chance for customers to be supplied during a system failure. The DG capital investment, operation and maintenance costs increase together with the rising of the DG size. The total cost, which is the most important factor in the optimization process, is changing with three different trends. It firstly shows a sharply decreasing, then decreases slowly, and finally starts to increase. This cost function defines the optimal DG size at which minimum payment made by the distribution company could be reached. For this particular case, it can be seen that the DG size is quite high when there are high line fault rates or when the reliability penalty is high.

Next, we examine a case when the DG location is not site-specified. This means that the DG can be located anywhere on the feeder. For this study, both the DG size and location are considered as decision variables of the optimization problem. As was shown from the previous study, the reliability penalty has a great impact on the overall results of the optimization process. To verify this finding, simulations were carried out to obtain the optimal DG planning for different prices of the load outage, ranging from $0 to $10,000 per MWh outage. Fig. 12 shows the optimal DG sizes and optimal DG locations with respect to the different reliability costs for the two levels of the nominal load demands. The results reveal that when the reliability penalty is high, optimal DG sizes and locations are mostly decided by the reliability factor. Otherwise, quality factor has the greatest impact on the optimization. The optimal DG size, as shown in Fig. 12, is the highest when the reliability cost is $10,000/MWh outage. The optimal size however reduces significantly as the reliability cost decreases. As shown in Fig. 12(a), when the reliability penalty is equal to or smaller than $2,000/MWh outage, the DG optimal size remains constant at around the 2% penetration level. Similarly, in Fig. 12(b), it can be seen that for the reliability penalty of $1,500/MWh outage, the DG optimal size is about 6% of penetration level. Also, it is shown that the best location for the DG is at the remote end. This can be explained by the fact that the DG located downstream of the feeder has more chance to form an active island in the case of a fault anywhere in the line. Yet, as the reliability cost decreases to zero, the DG moves from the remote end and is now located at bus 68 to provide a better system voltage support.
Depending on how critical the customer loads are, different rates of penalty for outage will be applied. For example, a loss of an industrial load or hospital will result in much greater costs compared to that of a residential load. Thus, types of load, which directly affect the reliability penalty, are of great importance in the optimization of the DG design and needed to be assessed with much care. The results imply that when the payment towards reliability is high, a high investment on the DG should be expected as a backup supply in the case of a system failure.

VI. CONCLUSION

This paper has introduced a DG as an alternative cost-effective solution in distribution system planning in response to increasing load demands. A new approach has been introduced to determine optimal size and location of the utility-operated DGs with the consideration of the long term cost benefits. An objective function is presented to estimate payments of a distribution company related to the capital investment, and operation and maintenance of a network as well as reliability and voltage quality charges in the presence of DGs. A realistic discount rate has also been taken into account. The proposed approach has been tested on a practical system and proved to be effective. Simulations have been extensively conducted for a variety of scenarios: constraints related to the DG location, different load demands, and consideration of the reliability penalty factor. Results show that voltage quality and transmission line losses have lesser impact on the total utility expenses than the reliability costs and the DG investment cost. In such cases that the high critical loads are connected to the
network (which means the reliability penalty is high), a higher penetration of the DG is required to provide an alternative power supply when the main supply fails.

REFERENCES


