REVIEW OF THE CONCEPTS TO INCREASE DISTRIBUTED GENERATION INTO THE DISTRIBUTION NETWORK

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REVIEW OF THE CONCEPTS TO INCREASE DISTRIBUTED GENERATION INTO THE DISTRIBUTION NETWORK

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Abstract

of

REVIEWS OF THE CONCEPTS TO INCREASE DISTRIBUTED GENERATION INTO THE DISTRIBUTION NETWORK

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Distributed Generation (DG) level of penetration is expected to be increasing due to the state and federal government’s mandates for utilization of renewable resources. State of California’s renewable standards [1], and the U.S. solar installations rapidly growing to 2.15GW in grid tied installed capacity in 2010 [2] are examples of such assertive mandated programs. The current Distribution Network (DN) was not originally designed for integration of DG at such high penetration levels. Improvements will need to be made to DN to facilitate safe and reliable interconnection of DG at higher penetration levels. This paper gathers and documents the major concerns such as; voltage, protection, and power quality related to DG interconnections as well as the issues with the existing design standards and criteria. Several different DN changes have been proposed to help resolve these issues. The focus of this paper is about the exiting DN
topology and DG integration issues, as well as documentation and discussion of the proposed solutions. Additional areas of research are identified for further consideration.

_________________________, Committee Chair
Dr. Mohammad Vaziri

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INTRODUCTION

In North America, the original design of the DN is based on uni-directional power flow, known as “radial” feeders. This radial design is to keep the voltage in acceptable parameters based on the minimum and the maximum load demands. Past investments in the feeder to improve the characteristics is based on fixing a problematic area, or a response to an increase in load [2]. Renewable targets created by state and federal regulatory commissions have set targets for the percentage of renewable energy being served to the consumer. California is leading the United States by requiring that 33% of all retail electricity sales be from renewable resources by the year 2020 [1]. Often these renewable resources are located in remote areas, and are limited in size. These small remote generation sites are often connected with the DN without any detailed studies or analysis. However, when DG is connected to the DN, it alters the performance of the entire DN [39-40]. The DN is no longer a radial system with a unidirectional power flow pattern. The problems associated with bi-directionality of the power flow are amplified with increased levels of DG. Some of the known impacts of DG are: voltage quality, protection equipment settings, desensitized relays, increased fault currents, increased maintenance of “hunting” equipment, and even islanding portions of the DN[11][15]. Much research has been done in these various areas identifying the concerns and issues as well as proposals for change of current standards and feeder design criteria [39]. The objective of this paper is to review the current DN topology, describe the problems
associated with DG penetration, and to compare, analyze and document some of the proposed solutions to increases in the amount of DG penetration levels on DN.
TOPOLOGY OF NORTH AMERICAN SYSTEMS

Historically, power is generated by large generation units and immediately stepped up to high voltage power lines. These power lines traverse significant distances from some remote areas to populated load centers where the voltage is stepped down to MV or even Distribution Substations (DS) for connections to distribution feeders. The main primary feeder branches into several primary laterals that then branch into several sub-laterals to serve the distribution transformers. The most common type of primary feeder is the radial-type feeder with uni-directional power flow. Generally, the main feeder is three-phase, with the laterals either three-phase or single-phase. This topology has low service reliability, due to any fault in the unidirectional power flow results in an outage for the entire section of the feeder. The distribution voltages range from 4kV to 35kV with the most common primary distribution voltage in use in North America as 12.47kV [3].

In a normal DN, the highest voltage is within the DS, usually at the output of the Load-Tap Changing transformers (LTC). The lowest voltage is usually at the furthest customer’s site. Both the high and the low voltages must be kept within tightly regulated standards of 0.95pu to 1.05pu (114V-126V on a 120V base) utilization voltage, as stated by the American National Standards Institute (ANSI) Service Voltage Standard C84.1 [4] [39].

To maintain the voltage level at a customer’s site, automatic voltage control is provided by bus regulation at substation, individual feeder regulators at the substation, and supplementary pole top line regulators along the feeder. A Voltage-Regulating Relay
(VRR) controls the tap changes based on the voltage settings, the bandwidth, and the time delay. LTC’s are limited to raising or lowering the voltage levels at the point of the tap changing transformer. Capacitors installed in a radial network, affect the voltages between the transformer, and the capacitor. One of the most economical, and therefore prevalent, ways to achieve voltage control is the use of LTC at the substation and shunt capacitors on the feeders and at the stations [2].

The approximate formula for Voltage Drop (VD) calculations given by (1) shows the relation between the parameters of the system and the load demand.

\[ VD = I_R R + I_X X_L \]  

(1)

Where; \( I_R \) and, \( I_X \) are the real and the reactive components of the current required by the load, \( R \) is the resistive component of the line and \( X_L \) is reactive component of the line.

VD is related to the Resistive (R) and Reactive (\( X_L \)) parameters of the line, with \( I_R \) and \( I_X \) flowing through the conductors of the distribution feeder.

Corrective measures such as adding a shunt Capacitor with reactance (\( X_C \)) as suggest be (2), can reduce the effect of the \( X_L \), lowering the vector magnitude of VD. This also will lower the magnitude of the current seen by the conductor and lower the line losses caused by \( I^2 \).

\[ VD = I_R R + I_X X_L - I_C X_C \]  

(2)
Where; $I_R$, $I_X$, $R$, $X_L$ are the parameters defined above, $I_C$ is the reactive current through the and $X_C$ is the reactive component of the capacitor.

\[
VD = |I_L| \times R_{\text{eff}} \times \cos \theta + |I_L| \times X_{\text{eff}} \times \sin \theta \quad (3)
\]
Where; $|I_L|$ is the magnitude of the line current, $R_{\text{eff}}$ is the calculated resistance to d, $X_{\text{eff}}$, is the calculated reactance to the point at distance “d”, and $\theta$ is the angle difference between the I and the V.

Distribution protection’s primary goals are; 1 - to detect and isolate the fault; 2 – to minimize the number of customers affected by a fault, and 3 - to minimize the duration of the fault, and if possible, 4 - to locate the fault. The most common fault experienced on a DN system is a line to ground fault, which may be sustained or momentary. A sustained fault refers to a conditions requiring repair of the line, such as the conductor that has fallen to the ground due to an accident. Momentary or transient fault refers to a condition that line may be re-energized without a need for any repairs. If a momentary fault was to occur on a fused lateral, then it needs to be cleared before fuses are blown to prevent interruption of service to the customers served by the lateral. To prevent fuses from blowing for this transient fault, the protection scheme requires a high-speed tripping breaker that can clear the fault before blowing of the fuse. Then an automatic reclosing scheme can re-energize the system by closing the breaker again resume the service to the customers. If the fault is a sustained or permanent type, then the fuse closest to the fault should blow to limits the number of customers affected and to isolate the troubles line location for repairs. To have the fuse closest to the permanent fault blow, the fuse and all other interrupting devices in series with it up to the feeder breaker must be time coordinated with one another. Usually the main feeder and feeder tie line are protected by breakers or reclosers rather than fuses. The coordination of these individual
components requires knowledge of the loads at each of the various taps and loads, as well as the characteristics of the protection devices should they fail [2]. Again, proper coordination of protective devices are designed to; eliminate service interruptions, minimize the extent of customers affected, and assist with the locating of the faults. As one can see by Fig. 2, a minimum of expensive equipment is used to achieve the goals of protection with a bidirectional power flow.

Figure 2. Example of a DN with switches, fuses and protection overlap shown.
HOW DG IS CAPABLE OF DISRUPTING THE DN

Adding DG into a simple DN drastically changes the DN environment and variables. One of the advantages is the reduction of demand on the main feeder and its tie lines, resulting in the delay or postponement of equipment upgrades due to load growth. Evenly dispersed generation also has the ability to support the local voltage, making the voltage profile more constant for DN is that suffered poor voltage levels before installation DG during peak loading scenarios. In reference [6], the authors were able to show that under normal operating conditions, the possibility of 100% DG integration resulted in voltages within operating limits. However, there are a large number of effects that are viewed as negative for the; design, voltage profile and protection of the DN. These negative effects limit the amount of generation that can be adopted on a DN.

With small generation (usually below 25% of individual customers power consumption), at only a few customers sites, few changes to the system are noticed. This type of generation is non-exporting in nature, and maintains the systems bidirectional power flow, reducing the load on the DN. The DG is generally incapable of islanding and therefore does not need to be monitored for such problem. The DG has the effect of improving voltages, and slightly destabilizes the protection equipment by changing the demand values and short circuit ratings originally used in the protection study. The losses in the DN are also reduced, benefiting the Distribution Network Operators (DNO)
costs [7]. If the generation is induction type, capacitor correction is recommended at the Point of Common Coupling (PCC) to keep power factors near unity.

With the introduction of small DG capable of exporting power from a customer’s site onto the lateral, some concerns although small are noticed. The voltage at the PCC on a weak network can cause the voltage to rise on the lateral with DG’s; while nearby laterals can be operating at significantly lower voltages. The voltage discrepancies can make for challenging voltage control issues on the DN, possibly requiring additional voltage regulating equipment, or the re-location of existing equipment. This size DG is capable of islanding a portion of the feeder, and needs to be monitored to prevent accidental islanding, and most importantly prevent the island from re-connecting with the grid while out of phase. The bidirectional power flow disrupts the simple protection equipment, requiring more protection equipment and complete review of the protection system and coordination of devices. Losses in the DN begin to increase costs for the DNO, and accelerate as more DG is added [7].

When larger number of small exporting DG’s, or large DG’s, that are capable of reverse power flow on the laterals and main feeders are present, the DN requires a complete re-design. The voltage regulating equipment will be incorrectly programmed, the protection equipment is completely inadequate in components and coordination for the power flows, and the system is a serious risk to the DG equipment and the DN operator. Many islanding scenarios of the feeder sections are possible with high
probabilities. Such conditions require preventative measures to safeguard the DG and DN equipment.

Capacitor Related Disruptions

Pole top switched capacitors correct power factor and improve voltage profile between the capacitor and power source. Due to daily load curves, mixtures of switched and fixed capacitors are often used on DN. Most capacitor banks are placed near the location of reactive demand, or roughly 2/3 of the distance down the mains on evenly loaded feeders. The addition of DG alters the effectiveness of the capacitors in several ways. If the DG is near unity PF, or if it is a synchronous generator (which is normally set at a fixed power factor schedule), the voltage at the PCC will usually rise, requiring the reduction of fixed capacitive support, and even the possible need of switched reactors to bring the voltage down. However, if the DG is an induction unit, the reactive support of the capacitors may no longer be adequate [8]. In addition, the dynamic nature of DG’s must be taken into account. Solar concentrating panels output greatly reduces with cloud shadows and wind turbines are equally affected by wind variability. This very non-uniform output further stresses the voltage control schemes.

Tap Changer Settings Disruption

On-Load Tap Changer (OLTC) transformers controlled by Automatic Voltage Control (AVC) relay are commonly used in the DN. As DGs are added to the DN, voltage regulation problems can arise, altering the performance of the AVC relay. Both
the power factor of the DG and the power factor of the load flowing through the OLTC can cause the AVC relay measured voltage to be shifted. This results in an inaccurate voltage control. At the very minimum, any introduction of DG into a DN requires a re-evaluation of the settings for the control equipment to verify that standards are upheld in individual worse case scenarios and loading conditions [9].

A simplified example of this inaccurate voltage control is shown in Fig. 3. Using equations (1) and (3), the actual VD and the value as determined by the LDC have been calculated for the location at the distance “d”. Load1 and Load2 are each set as 2MW with a Power Factor (PF) of 1. Load1, point “d”, and Load2 are located 4, 5, and 8 miles from the substation respectively. The feeder conductor used is 266.8-kcmil all aluminum conductor, with 37 strands and 53-inch geometric spacing. The impedance on the line is \( z = 0.386 + j0.6611 \) \( \Omega/\text{mi} \). The line-to-line operating voltage is 13.2kV. The DG’s output is varied from 0 to 4MW with PF=1 to determine its effect on the LDC’s accuracy. Once the values are obtained, (4) is used to show the percent difference between the actual VD and the one determined by LDC.

\[
\text{%Diff} = 100 \times \frac{\text{VD}_{\text{Actual}} - \text{VD}_{\text{LDC}}}{\text{VD}_{\text{Actual}}} \quad (4)
\]

Where; \( \text{VD}_{\text{Actual}} \) represents the true VD, and \( \text{VD}_{\text{LDC}} \) represents the LDC’s estimated VD.
Before the DG delivers power into the system, the LDC is accurate. As shown in Fig. 4, once the DG begins to inject power at Load1, the accuracy of the LDC deteriorates. This phenomena changes with the location of “d” with respect to the loads and DG(s) on a given LDC monitored line.
Protection Disruptions

The total fault current is the vector summation of the individual fault current contributions from each of the sources. This is primarily the short circuit ratings of the feeder, and all rotating loads. With the introduction of DG, the total fault current rises while, the contributions from each source decreases [15], [40]. Depending on the type and size of the cumulative DG, the larger the contribution, it could have to the fault current [10]. As the total fault current increases, the interrupting rating of the protective equipment must be re-evaluated for their adequacy [40]. Protection equipment is installed and set according to the current load profile and short circuit ratings. These settings are altered with the introduction of DG, and require the addition of more protection equipment, with updated protection schemes [11]. Currently to limit the need for large changes to the DN, National Standard IEEE 1547 [12] requires all generation to disconnect in the presence of a fault or disturbance on the feeder. As DG increases, the need to keep more generation online during nearby faults becomes more advantageous for system stability and reliability [13].

For example, in Fig. 5, the power flows from the substation to a main feeder equipped with other lateral feeders protected by breakers at each of the relays R1 through R3. If a fault occurred at location “F”, the protection scheme would be designed to trip R2 before R1, with R1 providing backup protection in case of miss-operation by R2.
However, if exporting capable DG is added in Fig. 6, then a fault at location “F1” must also be detected by each of new DG sources, namely G2 and G3. As the DG penetration levels increase, the contributions from each source will decrease, thus making fault detection less sensitive with longer clearing times from each of the sources [15]. This is highly undesirable.

The changing system conditions such as variability, present further issues. As G2 and G3 change dynamically, due to lack of wind or clouds on concentrating solar panels, the maximum and minimum fault values also change. As the fault values drift, the
protection scheme may not operate properly [11]. In Fig. 7, sympathetic tripping of G2 or G3 can also occur when fault “F2” occurs, and the DG’s contribution to the total instantaneous fault current exceeds the DG’s relay setting before the relay R2 or R3 senses and opens [14].

The DG is also capable of rendering a relay completely insensitive. In Fig. 7, if fault F2 occurs, the G4 generator adds to the total fault current, while the R3 relay sees lower fault values of fault current due to the reduced contributions from other sources depending on the type of DG and the distances between relay, generator and load [15]. This desensitization of the relay R3 causes a slower response, or even a lack of tripping, until the unit G4 trips [14].

![Diagram of DN with possibility of relay desensitization.](image)

Figure 7. Example of DN with possibility of relay desensitization.

Islanding Concerns

Islanding is possible when the DG is independently capable of supporting any portion of the DN. Human safety issues arise, as equipment may be energized when the servicemen believe it is de-energized. The island may not be operating correctly per
operational standards [4], with the possibility for improper grounding, voltage, frequency or adequate protective equipment. Reconnection to the rest of the grid when out of phase can cause fault like conditions and stresses to the equipment [16 17]. Passive islanding detection and disconnection can be accomplished by monitoring voltage, frequency and other system parameter variations and rate of changes at the DG’s PCC. However, if the DG and the islanded DN load are balanced, then the island can become a Non-Detection Zone (NDZ) [18]. Active anti-islanding monitoring is accomplished by the introduction in fluctuations in frequency, phase shifting, reactive power injection, current injection, positive feedback and other methods. These small fluctuations result in negligible changes when the system is operating normal, yet create significant detectable changes when the DG is part of an island. Hybrid approaches that combine both active and passive monitoring techniques will provide more robust systems of detection for the various islanding conditions [16-17].
HOW THE IMPACT OF DG CAN BE MINIMIZED TO ALLOW FOR MAXIMUM DG PENETRATION

Strategic investments in enabling technologies can greatly increase the DN’s ability to utilize an increase in DG. There have been a host of ideas to increase the capacity, and still maintain quality of service. Some concepts are simplistic, and some are revolutionary. The main proposals published for this purpose including their benefits and/or shortcomings are presented in the following sub-sections.

Upgrading Conductors

One of the original solutions to improve the DN power transfer capability has been the upgrade of feeder conductors. As an example, each DG can be put on its own, properly sized radial feeder, serving the local High Voltage / Medium Voltage (HV/MV) substation. While this solution works, it is inherently expensive and limits the realization of DG in remote locations where renewable resources such as wind and solar are more likely to be found. If the DG is placed on a weak network, and is incapable of realizing its full potential during low local consumption, the conductors between the DG and the HV/MV substation necessitate upgrading to increase the capacity of the DN to accept more DG. This is also an unattractive solution, as the cost to the DG may outweigh the gain in capacity increase.
Optimal Placement Planning

Individual DG related problems could be mitigated by technically proper placement of DG on feeders. However, there is concern that poorly placed, or incorrectly sized DG in a DN could limit the placement of additional DG [19]. Optimal Power Flow (OPF) is a widely available tool that most DNO’s use in case studies. The OPF software can be utilized to determine the maximum capacity of the DG on DN systems. The program can also determine the optimal placement of DG in the DN. To utilize this readily available tool, DG’s are modeled as negative loads. By using this method, the capacity evaluation can be modeled as a load addition problem, with the voltage and thermal limits of the lines taken into account. The system is at its capacity when the cost associated with negative load is minimized. This method can help point out where on the DN a particular DG unit would be most beneficial. Or, the locations where additional DG in would degrade the remaining network capacity. For example, a 1MW increase in a poor location can lower the DN capacity for DG at another bus by more than 2MW. Furthermore, using the OPF allows the identification of limiting factors, allowing the DN owner to accurately determine where strategic investments would allow additional DG to be added to the network. This is, however, a single point analysis, and would have to be repeated each time a DG is connected to the system [20].

Voltage Control

Voltage control is one of the most widely studied topics, and one of the most mature systems in the DN. The equipment includes capacitors, reactors, tap changing
transformers, Static Var Compensators (SVC), Static Synchronous Compensators (STATCOMS), and other devices. Many algorithms and fuzzy logic systems have been proposed and analytically shown that the existing voltage control equipment, with the proper modeling, may be capable of handling the increased dynamics of intermittent or increased DG [5,9,21-31]. However, all of these proposals will have to be tested and implemented in the field to prove practical viability. With the addition of FACTS devices further control may be possible [32-33]. As research in this area is so broad and widely studied, only a brief summary of two cost effective DG enabling mitigation techniques is required.

Specific case studies have shown that local voltage rise can be mitigated with the addition of a reactor at the DG’s PCC, and additional capacitors at the HV/MV substation. Although this is an inexpensive capacity increasing solution, this topology greatly increased the active power losses for the DN. The study also determined that the lowering of the upstream HV/MV stations voltage facilitated the most efficient network transfer capacity. Though this is one of the most cost-effective methods, it was noted that many DN operators would be unwilling to accommodate such a request [8].

DG capable of variable reactive injection support, coupled with utilization of SCADA communication on the distribution network, would facilitate the coordination between the voltage controlling equipment and ultimately a better system voltage profile. With this more complete information, all available voltage controlling equipment in the DN can be managed by a single algorithm. This centrally coordinated voltage algorithm
allows for more accurate usage of each individual component and keeps individual voltage controlling equipment from “hunting” of the regulating equipment. “Hunting” refers to a problem encountered when each regulating component utilizes only local voltage and current readings to control its output independent of other voltage controlling equipment. The independent local controls often causes initiate unnecessary steps depending on the corrective actions taken by other voltage regulators. With variable reactive support from the DG, even fewer actions are required by the existing voltage controlling equipment.[34] The cost for establishment of a centralized control system and associated communication scheme for this purpose will be significant.

Redesigning the Network to a Mesh System

As more DG is introduced, the power becomes bidirectional, much like the mesh networks of the HV power grid. This complete re-design also creates its own problems. The paralleling of the transmission network and the DN increases the short circuit duties on the system. The increased levels of fault currents alone will require equipment with higher interrupting rating which can easily go beyond the limits for distribution equipment, thus making the option impractical. Another meshed option may be balanced looped secondary sub-feeders, connecting consumers and producers. Despite the increased fault values, one of the advantages of such a system is for isolation of the faults. If a fault is on the main feeder, the normally open breakers, and closed breakers, can be rearranged to keep as much of the system energized as possible. If the fault is inside one of the loops, the fault is localized, and other loops are not affected. If the loop
is equipped with fault locating relays, the fault can be further isolated, splitting the loop into two radial sub-feeders. The study showed an increase from 47% maximum reachable DG insertion for a secured feeder, to 67% depending on the number of secondary loops. The authors verified that this topology is capable of service continuity and then argue that the cost savings due to the reduced power losses can be comparable to the secured feeder [35]. This point will have to be verified by future research and field implementation.

Islanding

Islanding falls into two categories; intentional and unintentional. Unintentional islanding can have disastrous effects as the island may be out of phase during the reconnection, system operators may be unaware that the equipment is energized, and systems of protection and voltage regulation will be inherently compromised. Standards IEEE 1547 [12] has a maximum delay of 2 seconds for a DG to detect and disconnect from an unintentional island. However, passive and active monitoring may not be enough for a timely detection and isolation of an unintentional island. Hybrid approaches that utilize passive and active monitoring are able to improve the speed of detection, decrease the threat of NDZ’s, and maintain little change in the power quality of the DG [16]. Some promising research has been completed in comparing the behavior of islanded and non-islanded Automatic Load Frequency Controllers (ALFC). The actions of the ALFC coupled with learned behavior of self-organizing map neural networks have shown to detect the difference between islanded and non-islanded operation within
200ms and 97.98% accuracy. The detection would signal the relay to disconnect at the PCC far faster than the required 2 seconds [36].

With intentional islanding, regulating and protecting the equipment is the primary concern. The benefits gained in terms of service reliability and deferment of revenue losses from larger area blackouts is promising. However, the infrastructure changes are also significant. Most synchronous generators are capable of islanded operation due to the nature of their excitation systems and the ALFC. However, induction generators absorb reactive power from the system thus requiring voltage support from equipment such as capacitors. Inverters are currently designed and set as constant current devices, not as voltage control devices. If the inverter based DG’s within the detected island are capable of sensing the island conditions and switching to a voltage control scheme, it is possible to intentionally control the island with load shedding schemes in place to keep high priority loads in service inside the island. This controlled island must also be able to re-syncronize with the grid as part of the scheme with the inverter based DG’s reverting back to the constant current mode of operation [37].

Fault Current Limiting Devices

Higher levels of DG penetration increase the short circuit current (I_{SC}) in the DN [10],[15],[40]. There are ways to mitigate this increase through the use of Superconducting Fault Current Limiting Devices (SFCL). The two primary types are resistive and inductive superconductors. In a resistive type, the resistance is nearly negligible, until a large fault creates enough heat to quench the superconductor, then the
SFCL becomes resistive and limits the fault. An inductive type is like a transformer with a closed superconductor ring for a secondary winding. During normal operation, the resistance of the secondary is negligible, however, in the presence of a fault the superconductor is quenched and the impedance of the primary rises sharply. With all protection equipment, there is very short delay (fractions of a cycle) between a fault and when the circuit breaker is initiated to trip. With the SFCL in use, the current is limited ($I_{lim}$) for a duration equal or slightly greater than the automatic switching device by design. In [38] the installed SFCL results showed that; without the SFCL the $I_{SC}$ were 1650Amps peak, and did not diminish with time. With the SFCL in place, the tests were repeated, and the $I_{lim}$ was 960Amps at the beginning of the fault and 310Amps when the fault was cleared. This diminishing of fault current was due to the temperature dependant resistive properties of the SFCL. Such devices can theoretically allow more DG to be added into the DN while limiting the negative impacts. Further research and field tests are required for verification of results in practical systems.

Adaptive Protective Relaying

By the existing rules and criteria, each of the contributing energy sources such as the substation or any interconnected DG is responsible to detect the faults on the DN system and interrupt its own contribution. This removes the benefits that DG can offer a system support during a nearby fault that may be isolated by other devices [13]. The DN protection system could be designed to adapt to the changing environment, using a host of new equipment and communication. The configuration consists of relays with
communication links to downstream and adjacent current protective equipment. Each relay would be equipped with both adaptive primary and secondary functions. If a fault occurs in a primary zone of protection, the loads and DG currents upstream of the relay are measured and sent to the relay. The relay is capable of identifying the fault using various analytical techniques, and isolates the faulted zone with the appropriate breakers. If a fault occurs in the backup zone, the loads and DG currents downstream of the relay are transformed to branch currents, whereby the changes associated with the loads and DG’s can be eliminated. This system has shown to be highly effective, and able to improve the protection performance under changing load and generation [14]. Additional research and studies are needed to verify practicality of this concept.
CONCLUDING REMARKS

Renewable targets created by state and federal regulatory commissions, and residential installation of co-generation have begun to alter the dynamics of DN. A number of valid concerns and issues related to Voltage Regulation [11], Protection [39-40], and existing standards [15] have been reported for the DN by the research as the penetration level of DG increases. Voltage concerns are related to higher than normal voltages seen by the customers located near DG. Relay desensitization is experienced due to reduction in levels of fault current contributions associated with interconnection of additional DG. As shown in Fig.4 LDC’s lose the ability to accurately predict the VD with the introduction of DG, and may cause voltages to rise or fall outside of the operating standards [9]. Despite the issue and concerns, some research has also shown that strategic investments in enabling technologies can greatly increase the DN’s ability to utilize an increase in DG. National Standard IEEE 1547 [12] is a stepping-stone to furthering the possibilities of DG, as separate standards focused on high DG penetration are needed. Optimization of generation location is currently a tedious process and further research on rapid analyzing for multiple generators and locations would be beneficial. Voltage control, despite how widely it has been studied, will need further research and investigation as multiple solutions to other problems alter the existing topology. Mesh topology offers solutions to many problems, and introduces a host of new scenarios to study. Investigations will include; transitioning from radial to mesh, the cost, maintenance, short circuit studies, voltage control, and system protection. The use of hybrid detection techniques has shown effective reduction of the NDZ. Using the ALFC
for island detection although considered a novel approach, it lacks verification through additional research and case studies. FCL’s have shown to be effective in test environments. While the installation at practical sites, cost minimization, and its effect on the system need further investigation. Advancements in relay techniques focused on the interaction of varying levels of generation also needs further research to verify their adequacies for protection of the DN with higher levels of interconnected DG.
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