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Foundational Report Series: Advanced Distribution Management Systems for Grid Modernization

DMS Integration of Distributed Energy Resources and Microgrids

Energy Systems Division

ANL/ESD-17/8

Foundational Report Series: Advanced Distribution Management Systems for Grid Modernization

DMS Integration of Distributed Energy Resources and Microgrids

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FOUNDATIONAL REPORT SERIES

DISTRIBUTION MANAGEMENT SYSTEMS FOR GRID MODERNIZATION

This is one of seven reports on distribution management systems (DMS), their functions, implementation, and importance for grid modernization.

The reports on DMS in this numbered series of Argonne reports are as follows:

1. Importance of DMS for Distribution Grid Modernization (ANL/ESD-15/16)
2. DMS Functions (ANL/ESD-15/17)
3. High-Level Use Cases for DMS (ANL/ESD-15/18)
4. Business Case Calculations for DMS (ANL/ESD-17/3)
5. Implementation Strategy for DMS (ANL/ESD-17/6)
6. DMS Integration of DER and Microgrids (ANL/ESD-17/8)
7. DMS Industry Survey (To Be Published)

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ACRONYMS AND ABBREVIATIONS

AMI	Advanced metering infrastructure
APC	Active Power Control
CT	Combustion turbine
DER	Distributed Energy Resource
DERMS	Distributed Energy Resource Management System
DG	Distributed generation
DMS	Distribution Management System
EMS	Energy Management System
EV	Electric vehicle
FCI	Faulted Circuit Indicator
FLISR	Fault Location Isolation and Service Restoration
ICE	Internal combustion engine
IED	Intelligent Electronic Device
LC	Local controller
LDC	Line drop compensation
LTC	Load Tap Changer
MCC	Microgrid Central Controller
MMS	Microgrid Management System
OMS	Outage Management System
PFL	Predictive Fault Location
POI	Point of interconnection
PV	Photovoltaics
SCADA	Supervisory Control and Data Acquisition
VPP	Virtual Power Plant
VR	Voltage regulator
VVO	Volt-VAR optimization

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1 INTRODUCTION

Deregulation of the electric utility industry, environmental concerns associated with traditional fossil fuel-based power plants, volatility of electric energy costs, Federal and State regulatory support of "green" energy, and rapid technological developments all support the growth of Distributed Energy Resources (DERs) in electric utility systems and ensure an important role for DERs in the smart grid and other aspects of modern utilities. DERs include distributed generation (DG) systems, such as renewables; controllable loads (also known as demand response); and energy storage systems.

Large-scale implementation of DERs can lead to situations in which the distribution/medium-voltage network evolves from a "passive" system (with local/limited automation, monitoring and control) to a global/integrated, self-monitoring, semi-automated system that responds to the various dynamics of the electric grid. This evolution poses a challenge for design, operation and management of the power grid, as the network no longer behaves as it was originally designed to. Consequently, the planning and operation of new systems must be approached somewhat differently, with a greater amount of attention paid to overall distribution system challenges.

Distribution management systems (DMS) and other elements of grid modernization will play a major role in managing the impacts of DERs on the electric distribution system. This management includes mitigating the adverse impacts of DERs on distribution system performance, as well as using DERs to improve (optimize) the electric distribution system.

This report describes the role of aggregators of DERs in providing optimal services to distribution networks, through DER monitoring and control systems—collectively referred to as a Distributed Energy Resource Management System (DERMS)—and microgrids in various configurations.

1.1 OBJECTIVES AND SCOPE

As the penetration of DERs in electric distribution systems increases, the impacts of these devices (both positive and negative) will become more significant. Adverse impacts of intermittent renewables, including voltage regulation concerns, will require more active management by control center personnel to avoid degradation of overall power quality. Active management of DERs by the electric utility will provide opportunities for improved distribution system performance. For example, distributed generators that are equipped with smart inverters will be able to play a role in accomplishing Volt-VAR optimization (VVO) strategies by supplying or absorbing reactive power when needed. In addition, DERs, including energy storage devices as well as distributed generators, will play a significant role in achieving the "self-healing" grid by freeing capacity for load transfers when needed and by creating microgrid islands to restore power to customers and portions of the electric distribution system that have no backup source of power.

This report describes the role of the DMS in enabling an active control of DERs for mitigating adverse impacts and accomplishing overall improvement of the electric distribution system's performance. This report also includes an overview of smart distribution applications for monitoring and controlling DERs. The importance of DERs for VVO, reliability improvement measures, system reconfiguration, microgrid operation and control, and other DMS applications is explored.

1.2 ORGANIZATION OF THE REPORT

This report comprises six chapters:

- Chapter 1 – Introduction: This chapter provides important background, and describes the overall organization of the report.
- Chapter 2 – Impact of Distributed Energy Resources on Distribution System Design and Operation: The principal goal of this chapter is to address the topic of high penetration of DERs and their impact on grid design and operations.
- Chapter 3 – Impact of Distributed Energy Resources on Grid Modernization Strategy: This chapter describes the potential impacts—both positive and negative—that increasing penetration of DERs can have on the operation and effectiveness of grid modernization applications.
- Chapter 4 – Distributed Energy Resource Management Systems: This chapter discusses using electric utility-owned monitoring and control systems, such as DMS, to manage the DERs themselves to improve distribution system reliability, efficiency, and performance.
- Chapter 5 – Using Standards to Integrate DERs with DMS: This chapter describes industry standards that are being developed to facilitate integration of DERs with other enterprise systems. The chapter includes a set of proposed functions for managing smart AC inverters. The role of standards for DER integration, communication, and enterprise integration is also discussed.
- Chapter 6 – Conclusions and Recommendations: In this chapter, the needs for a proactive approach and for industry-wide standards are noted.

2 IMPACT OF DISTRIBUTED ENERGY RESOURCES ON DISTRIBUTION SYSTEM DESIGN AND OPERATION

This chapter addresses the topic of high penetration of DERs and their impact on grid design and operations. The following sections describe centralized vs. distributed generation, the portfolio of DER technologies, and DER design/engineering challenges.

2.1 CENTRALIZED VS. DISTRIBUTED GENERATION

The bulk of electric power used worldwide is produced at central power plants, mostly via fossil fuel combustion, hydro, or nuclear reactors. Most of these central stations have an output between 30 MW (industrial plant) and 1,700 MW. This capacity makes them relatively large in terms of both physical size and facility requirements, as compared with DG alternatives. In contrast, DG is:

- Installed at various locations (closer to the load) throughout the power system.
- Not centrally dispatched (although the development of "virtual" power plants, or VPPs, where many decentralized DG units operate as a single unit, may be an exception to this definition).
- Defined by a power rating in a wide range, from a few kW to tens of MW (in some countries, the MW limitation is defined by standards; e.g., IEEE 1547 defines DG as up to 10 MW, either from a single unit or as aggregate capacity).
- Connected to the distribution/medium-voltage network (this term generally refers to the part of the network that has an operating voltage ranging from 600 V up to 110 kV, depending on the utility/country).

Ownership has nothing to do with classifying a generator as a DG system or not. DG systems can be owned/operated by electric customers, energy service companies, independent power producers, or utilities.

The main reasons that central, rather than distributed, generation still dominates current electricity production include economy of scale, fuel cost and availability, and lifetime costs. Increasing the size of a production unit decreases the cost per MW; however, the advantage of economy of scale is decreasing because technological advances in fuel conversion have improved the efficiency and fuel economy of small units. Fuel cost and availability remain as reasons to build large, central power plants. Additionally, with a lifetime of 25–50 years, large power plants will remain the prime source of electricity for many years to come.

The potential benefits of DG include higher efficiency; improved security of supply; improved demand-response capabilities; avoidance of overcapacity; better peak load management; reduction of grid losses; network infrastructure cost deferral (CAPEX deferral);

power quality support; reliability improvement; and environmental and aesthetic concerns (DG offers a wide range of alternatives to traditional power system design). DG provides a flexible range of trade-offs between cost and reliability. In addition, DG may eventually become a more desirable generation asset because it is "closer" to the customer and is more economical than central station generation and its associated transmission infrastructure. The disadvantages of DG are the complexities of ownership and operation, fuel delivery issues (machine-based DG, remote locations), cost of connection, dispatchability, and controllability (especially for wind and solar).

Technologies that are available to adapt to changes in generation mix are found in distribution automation, distribution management, and demand management.

- **Distribution Automation:** Grid performance can be improved by advanced distribution and substation automation (self-healing); wide-area adaptive protection schemes (special protection schemes); wide-area monitoring and control systems (PMU-based situational awareness); asset performance optimization and conditioning (CBM); dynamic rating; advanced power electronics (FACTS, intelligent inverters, etc.); high-temperature superconducting systems; and many other approaches.

- **Distribution Management:** Distribution utility-side applications include DMS; Energy Management Systems (EMS); Outage Management Systems (OMS); demand response; advanced applications to enable active voltage and reactive power management (IVVC, CVVC); advanced analytics to support operational and enterprise decision making; DER management; microgrids and VPPs; work force management; geospatial asset management (GIS); KPI dashboards and advanced visualization; and many others.

- **Demand Management:** Customer-side technologies include advanced metering infrastructure (AMI); home/building automation; EMS and display portals; electric vehicle (EV) charging stations; smart appliances; and many others.

2.2 DER TECHNOLOGY LANDSCAPE

DER technology has significantly advanced in recent years. Today, DERs not only act as an active source of energy, but they also participate in demand response, storage, and energy transactions. They also form the basis for microgrids. On the basis of their needs and operational capabilities, a wide range of stakeholders (residential and utility, commercial and industrial, institutional and campuses, vendors, remote off-grid) are taking advantage of advances in technology, applications, and diverse deployment configurations in the DER domain to improve their portfolios.

DER technologies are characterized according to a number of criteria:

- Type of generation
  - Non-renewable generation
    - Combustion turbine (CT) generators
    - Microturbines
    - Internal combustion engines (ICEs)
    - Small steam turbine units
  - Renewable generation
    - Low/high-temperature fuel cells (e.g., AFC, MCFC, PAFC, PEMFC, SOFC, DMFC)
    - Photovoltaics (PV) (mono-, multicrystalline)
    - Concentrated PV
    - Thin-film solar
    - Solar thermal
    - Hydroelectric (e.g., run-of-river)
    - Wind/mini-wind turbines
    - Tidal/wave
    - Ocean thermal energy conversion (e.g., land-, shelf-, floating-based plants; open, closed and hybrid cycles).
- Size of generation (a few kW to hundreds of MW)
- Distribution network (radial, meshed, open/closed loop)
- Location where the DER needs to be deployed and accessed
- Load control potential
- Energy storage potential and need
- Control capability and response time (primary, secondary and tertiary control, frequency reserve, ramping reserve, load-following reserve, fault ride-through capability, dispatchable/non-dispatchable)

All these technologies differ from each other in such parameters as electrical efficiency, performance, installation footprint, initial capital investment, and cost of operation. Depending on the technology portfolio, the technology configurations, and the needs of stakeholders, greater or lesser benefits will be realized; there are tradeoffs specific to the utility. Thus, particular attention should be paid to these tradeoffs when selecting a technology portfolio for deployment.

2.3 DER DESIGN AND OPERATIONAL CHALLENGES

DER interconnection engineering and engineering details depend on the specific installation size (kW vs. MW); however, the overall components of the installation should include the following:

- DG prime mover (or prime energy source) and its power converter
- Interface/step-up transformer
- Grounding (when needed—grounding type depends on utility-specific system requirements)

- Microprocessor protective relays for:
  - Three-, single-phase fault detection and DG overload
  - Islanding and abnormal system conditions detection
- Voltage and current imbalance detection
  - Undesirable reverse power detection
  - Machine-based DG synchronization
- Disconnect switches and/or switchgear(s)
- Metering, control and data logging equipment
- Communication link(s) for transfer trip and dispatch control functions (when needed)

Table 2-1 summarizes the common DG interconnection requirements of utilities for various DG sizes (some details will vary on the basis of utility-specific design and engineering practices).

TABLE 2-1 DG Interconnection Requirements of Utilities

Requirements	DG less than 10kW	DG 10-100kW	DG 100-1000kW	DG >1000kW or >20% feeder load
Disconnect switch	Yes	Yes	Yes	Yes
Protective relays: islanding prevention and synchronization	Yes	Yes	Yes	Yes
Other protective relays (e.g. unbalance)	Optional	Optional	Yes	Yes
Dedicated transformer	Optional	Optional	Yes	Yes
Grounding impedance (due to ground fault contribution current)	No	No	Optional	Often
Special monitoring and control requirements	No	Optional	Yes	Yes
Telecommunication and transfer trip	No	Optional	Optional	Yes

DG Integration and "Penetration" Level

Integration of DG may have an impact on system performance. This impact can be assessed on the basis of the following:

- Size and type of DG design: power converter type, unit rating, unit impedance, relay protection functions, interface transformer, grounding, etc.
- Type of DG prime mover: wind, PV, ICE, CT, etc.
- Interaction with other DG system(s) or load(s)
- Location in the system and the characteristics of the grid:
  - Network, auto-looped, radial, mesh
  - System impedance at point of interconnection

– Voltage control equipment types, locations and settings
– Grounding design
– Protection equipment types, locations, and settings
– Others

DER system impact is also dependent on the "penetration" level of the DG system connected to the grid. A number of factors should be considered when evaluating the penetration level of DG in the system. Examples of DG penetration level factors include the following:

- DG as a percent of feeder or local interconnection point peak load (varies with location on the feeder)

- DG as a percent of substation peak load or substation capacity

- DG source fault current contribution as a percent of the utility source fault current (at various locations)

DG Impact on Voltage Regulation

Voltage regulation, and in particular voltage rise effect, is a key factor that limits the amount (penetration level) of DG that can be connected to the system. Figure 2-1 shows the first example: a network with a relatively large (MW-size) DG system interconnected in close proximity to the utility substation.

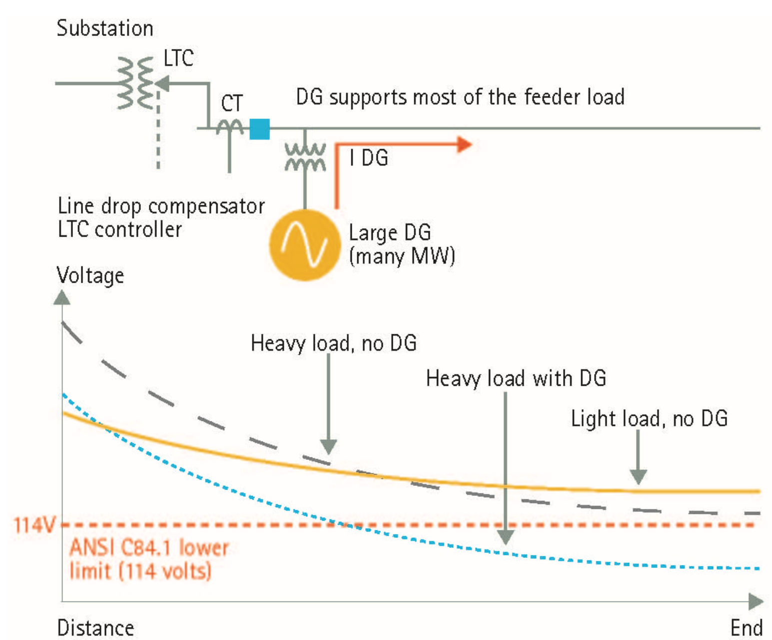
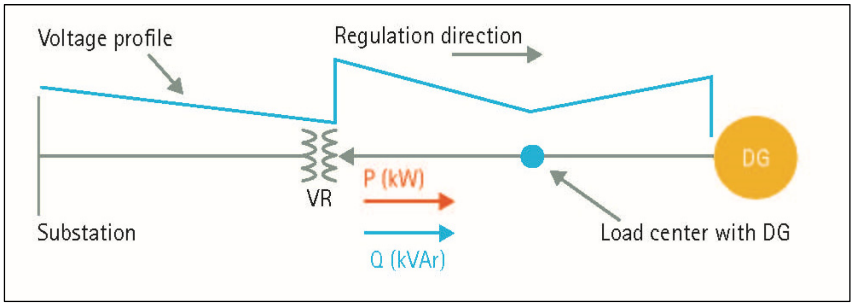


FIGURE 2-1 DG[1] Connection Close to the Utility Substation

[1] Large DG refers to either a single DG unit or the aggregation of several DG units.

Careful investigation of the voltage profile indicates that under heavy load conditions, with connected DG, voltage levels may drop below acceptable/permissible standards. The reason for this condition is that relatively large DG reduces the circuit current value seen by the Load Tap Changer (LTC) in the substation (DG current contribution). Since the LTC sees "less" current (representing a light load) than the actual value, it will lower the tap setting to avoid a "light load, high voltage" condition. This action makes the actual "heavy load, low voltage" condition even worse. As a rule, if the DG system contributes less than 20% of the load current, then the DG current contribution effect will be minor and can probably be ignored in most cases.

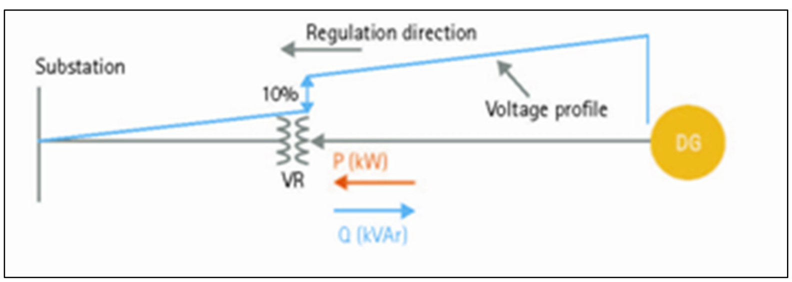
Figures 2-2 and 2-3 show a second example: a network with DG connected downstream from the bi-directional line voltage regulator (VR). During "normal" power flow conditions (Figure 2-2), the VR detects the real power (P) flow condition from the source (substation) toward the end of the circuit. The VR will operate in "forward" mode (secondary control). This operation is as planned, even though the "load center" has shifted toward the VR.



Source: General Electric

FIGURE 2-2 Voltage Regulator Bi-directional Mode (Normal Flow)

However, if the real power flow direction reverses, toward the substation (Figure 2-3), the VR will operate in the reverse mode (primary control). Since the voltage at the substation is a stronger source than the voltage at the DG unit (which cannot be lowered by the VR), the VR will increase the number of taps on the secondary side; therefore, voltage on the secondary side will increase dramatically.



Source: General Electric

FIGURE 2-3 Voltage Regulator Bi-directional Mode (Reverse Flow)

DG Impact on Power Quality

Two aspects of power quality are usually considered to be important during evaluation of DG impact on system performance: (1) voltage flicker conditions and (2) harmonic distortion of the voltage. Depending on the circumstances, a DG system can either decrease or increase the quality of the voltage received by other users of the distribution/medium-voltage network. Power quality is an increasingly important issue and generation is generally subject to the same regulations as loads. Increasing the grid fault current by adding generation often leads to improved power quality; however, it may also have a negative impact on other aspects of system performance (e.g., protection coordination). A notable exception is that a single large DG unit, or an aggregate of small DG units, connected to a "weak" grid may lead to power quality problems during starting and stopping conditions or output fluctuations (both normal and abnormal). For certain types of DG systems, such as wind turbines or PV, current fluctuations are a routine part of operation because of varying wind or sunlight conditions (Figure 2-4).

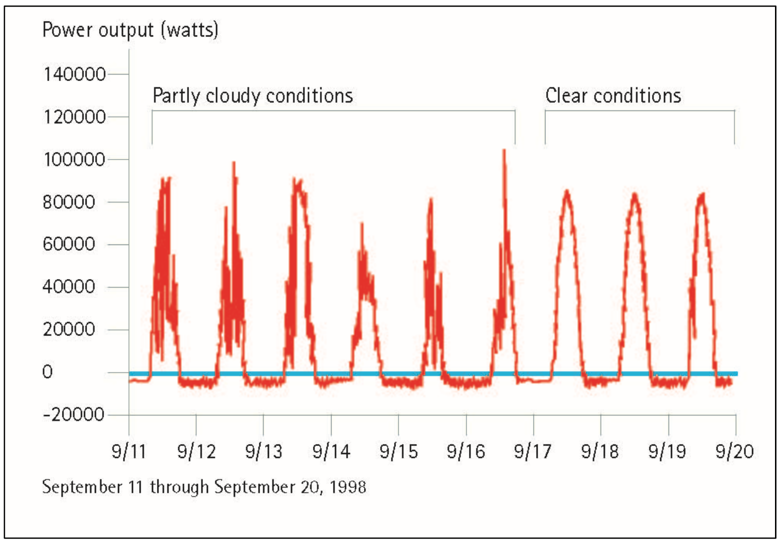


FIGURE 2-4 Power Output Fluctuation for 100-kW PV Plant

Harmonics (waveform distortions) may cause interference with operation of some equipment, including overheating/de-rating of transformers, cables and motors, leading to shorter life. In addition, they may interfere with some communication systems located in close proximity to the grid. In extreme cases, they can cause resonant overvoltages, "blown" fuses, failed equipment, etc. DG technologies must comply with pre-specified standards with respect to harmonic levels (Table 2-2).

To mitigate harmonic impact in the system, the following can be implemented:

- Use an interface transformer with a delta winding or ungrounded winding to minimize injection of triplen harmonics.
- Use a grounding reactor in neutral to minimize triplen harmonic injection.
- Specify a rotating generator with 2/3 winding pitch design.
- Apply filters or use phase-canceling transformers.
- For inverters: specify PWM inverters with high switching frequency. Avoid line-commutated inverters or low-switching-frequency PWM; otherwise, more filters may be needed.
- Place DG units at locations with high ratios of utility short-circuit current to DG unit rating.

TABLE 2-2 Current Distortion Limits for General Distribution Systems (IEEE 519 – 1992)

Maximum harmonic current distortion in % of I_L						
Individual harmonic order (odd harmonics)						
I_{SC}/I_L	< 11	$11 \leq h < 17$	$17 \leq h < 23$	$23 \leq h < 35$	$35 \leq h$	TDD
< 20*	4.0	2.0	1.5	0.6	0.3	5.0
20 < 50	7.0	3.5	2.5	1.0	0.5	8.0
50 < 100	10.0	4.5	4.0	1.5	0.7	12.0
100 < 1000	12.0	5.5	5.0	2.0	1.0	15.0
> 1000	15.0	7.0	6.0	2.5	1.4	20.0

Even harmonics are limited to 25% of the odd harmonic limits. TDD refers to total demand distortion and is based on the average maximum demand current at the fundamental frequency, taken at the PCC.

*All power generation equipment is limited to these values of current distortion regardless of I_{sc}/I_L.

I_{sc} = Maximum short circuit current at the PCC

I_L = Maximum demand load current (fundamental) at the PCC

h = Harmonic number

DG Impact on System Protection

Some DG units will contribute current to a circuit current on the feeder. The current contribution will raise fault levels and, in some cases, may change fault current flow direction. The impact of DG fault current contributions on system protection coordination must be considered. The amount of current contribution, its duration, and whether or not there are any protection coordination issues depend on the following:

- Size and location of DG unit on the feeder
- Type of DG unit (inverter, synchronous machine, induction machine) and its impedance
- Settings for DG unit protection equipment (how fast it trips)
- Impedance, protection and configuration of feeder
- Type of DG unit grounding and interface transformer

Machine-based DG systems (ICEs, CTs, some microturbines and wind turbines) inject fault current levels of 4–10 times their rated current with a time contribution between 1/3 cycle and several cycles, depending on the machine. Inverters contribute about 1–2 times their rated current to faults and can trip off very quickly—many in less than 1 cycle, under ideal conditions. Generally, if fault current levels are changed less than 5% by the DG system, then it is unlikely that fault current contribution will have an impact on the existing system/equipment operation. Utilities must also consider the interrupting capability of the equipment; e.g., circuit breakers, reclosers, and fuses must have sufficient capacity to interrupt the combined DG system and utility source fault levels. Examples of DG fault contributions to system operation and possible protection miscoordination are shown in Figures 2-5 and 2-6.

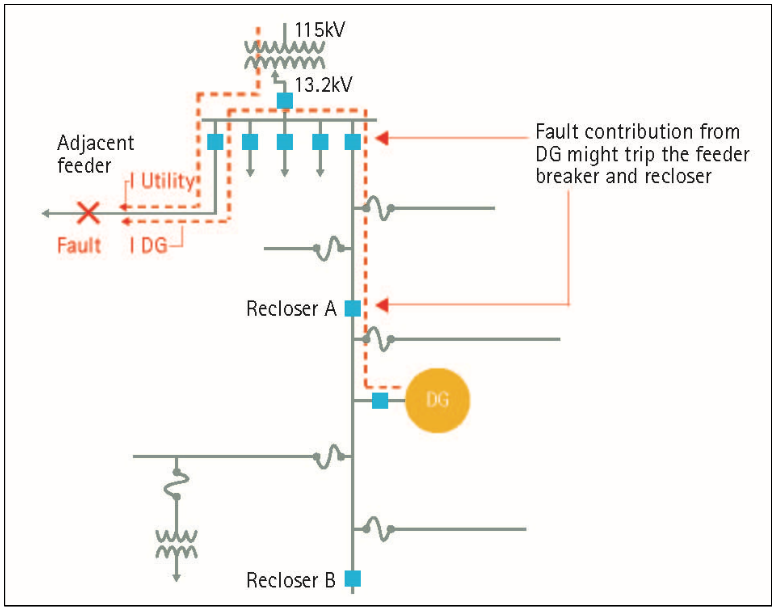


FIGURE 2-5 Undesirable Protection Trip (Back-feeding)

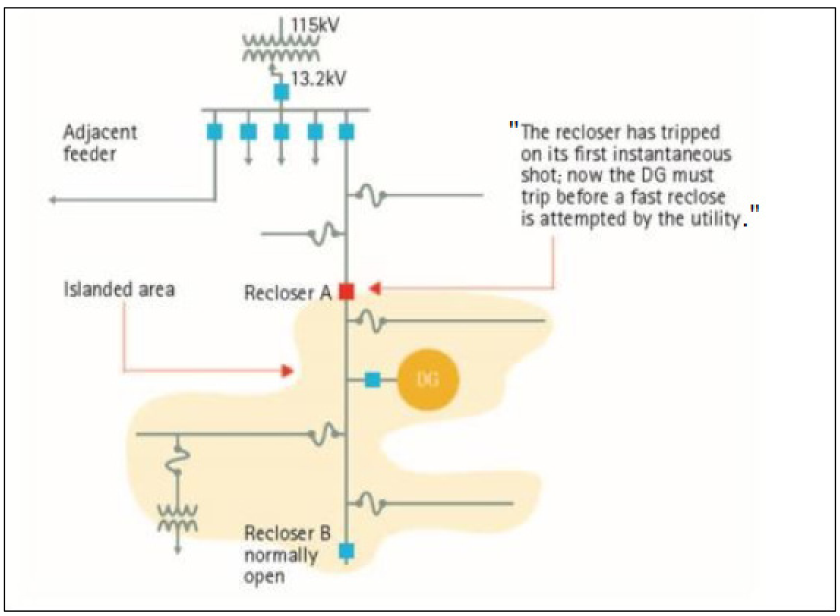


FIGURE 2-6 Unintentional DG Islanding

3 IMPACTS OF DISTRIBUTED ENERGY RESOURCES ON GRID MODERNIZATION STRATEGY

In recent years, many distribution utilities have developed and have begun implementing grid modernization strategies. Key objectives of these strategies include improving overall efficiency through reduced losses and energy conservation, and implementing a "self-healing" distribution grid. Volt-VAR control and distribution automation schemes have been developed and implemented to help accomplish these objectives.

This chapter describes the potential impacts—both positive and negative—that rising penetration of DERs can have on the operation and effectiveness of these grid modernization applications.

3.1 IMPACT OF DERS ON VOLT-VAR CONTROL AND OPTIMIZATION

Elements of the smart grid impose numerous challenges for the voltage control requirements for electric distribution feeders. Perhaps the most significant challenges are associated with the presence of large-scale DERs (distributed generators, renewables, and energy storage) out on the distribution feeders.

Impact on Line Drop Compensation

Traditional voltage control schemes often use line drop compensation (LDC) to regulate feeder voltage. The LDC scheme uses the bus voltage measurement, measured power flow through the VR or LTC, and VR settings representing the line resistance and reactance to compute the voltage at a fictitious point on the feeder that is near the load center of the feeder. Figure 3-1 illustrates the use of line drop compensation on a feeder that does not have a significant amount of DG present.

The LDC scheme usually assumes that all power delivered to the distribution circuit passes through the substation transformer LTC. LDC uses the current flow measurement and LDC settings that represent the resistance and reactance on the line to compute the voltage at a specified point out on the distribution circuit. When the voltage drop computed by LDC is small, the VR will lower its tap setting to lower the substation bus voltage and avoid possible high-voltage problems on the feeder. This condition is shown as the solid black line in Figure 3-1.

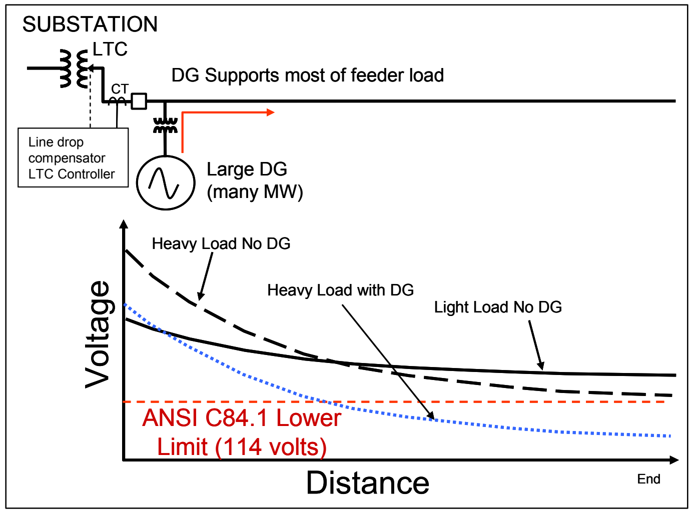


FIGURE 3-1 Conventional Line Drop Compensation

During peak load periods, if no DG is present on the feeder, current flow through the substation transformer increases and the voltage drop computed by LDC is higher. Therefore, the LTC raises its tap position, as shown in the dashed black line in Figure 3-1, to keep the minimum feeder voltage above the minimum acceptable voltage.

If a large DG unit is present close to the substation (as shown in Figure 3-1), a significant portion of the load may be supplied by the generator and a portion will pass through the LTC. In such cases, a traditional VR or LTC using LDC may interpret the lower through-current flow as a feeder minimum load condition when the load is actually near peak load. If so, the VR or LTC may actually lower the voltage when increased voltage is needed, as shown in the dashed blue line in Figure 3-1.

To address this situation, the VR must adjust its LDC settings to account for electric power that does not pass through the substation transformer. One approach is to use a DMS or equivalent processor to monitor or estimate the output of DG units connected to the feeder. This monitored or estimated value is added to the measured substation load to determine the actual feeder load for LDC purposes. The DMS may then download new settings to the VR's Intelligent Electronic Device (IED). Alternatively, the DMS may use the as-operated model to determine the desired VR or tap changer position and then use Supervisory Control and Data Acquisition (SCADA) to directly raise or lower the tap setting as needed.

Impact of Variable Distributed Energy Resources

If a high enough penetration of DERs exists on the distribution feeder, these resources can produce power flow in the reverse direction (back towards the primary electric utility substation), often producing a voltage rise as one moves further from the substation instead of the normal voltage drop.

The power output of wind-powered and solar-powered DERs may vary considerably throughout the day. As the power output from these generating sources rises and falls, a corresponding change in the power drawn from the normal, electric utility-supplied source (the substation) occurs so that the total power delivered to the feeder matches the consumed power at any given time. Such changes in power delivery sources can have a significant impact on power flow direction and magnitude and voltage magnitude at any point on the feeder.

This section discusses the impact of power and voltage fluctuations associated with DERs and ways to mitigate them.

With no generating sources on the feeder, or when the output from DERs is zero or near-zero, power flow is unidirectional (from the substation to the end of the feeder). Ignoring the effects of capacitor banks and VRs that are installed on the distribution feeders (outside the substation fence), distribution primary voltage drops off further from the substation. Figure 3-2 depicts this situation.

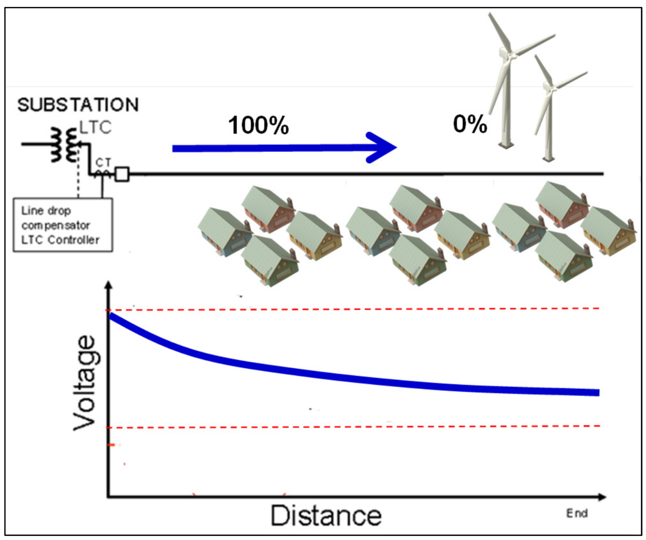


FIGURE 3-2 Voltage Profile with No DG

With a high penetration of the feeder by DG (e.g., DG supplies more than 20% of the feeder load), power flow in the reverse direction (towards the substation) may occur. This is especially likely to occur during off-peak periods, when the feeder is lightly loaded. Figure 3-3 shows the voltage profile when a DG unit that is connected towards the end of the feeder supplies 40% of the load on the feeder under lightly loaded conditions. In this simple example, the electric power output of the wind-power generators is enough to supply the entire load that is downstream of the generator (further from the substation) plus a portion of the upstream load. This results in a voltage drop-off towards the substation in portions of the feeder that experience reverse power flow. In other words, a voltage rise occurs further from the substation. As seen in Figure 3-3, primary voltage is near the maximum allowable value under these conditions.

Since the load supplied via the substation transformer is reduced, the LTC will reduce the voltage at the substation end of the feeder after a short time delay (10 to 30 seconds). This time delay is needed to prevent the LTC from operating during short-duration load changes, which could greatly increase the total number of tap changer operations (and thereby increase LTC maintenance costs). Figure 3-4 shows the resulting voltage profile.

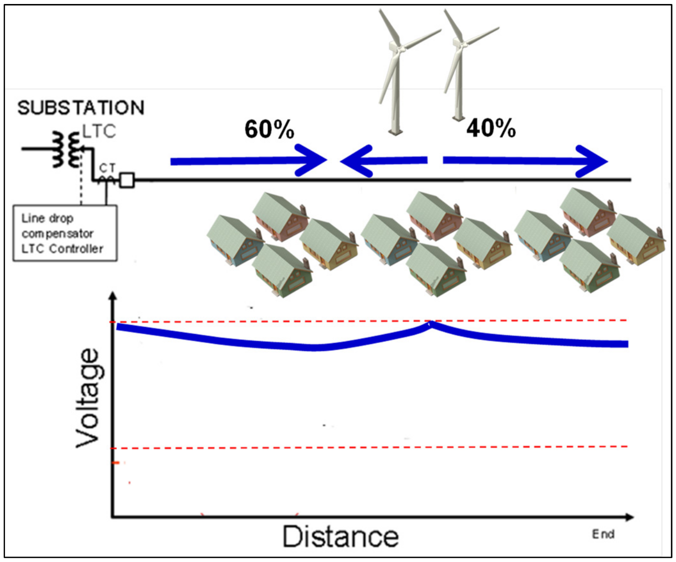


FIGURE 3-3 Voltage Profile with Significant DG Power Output

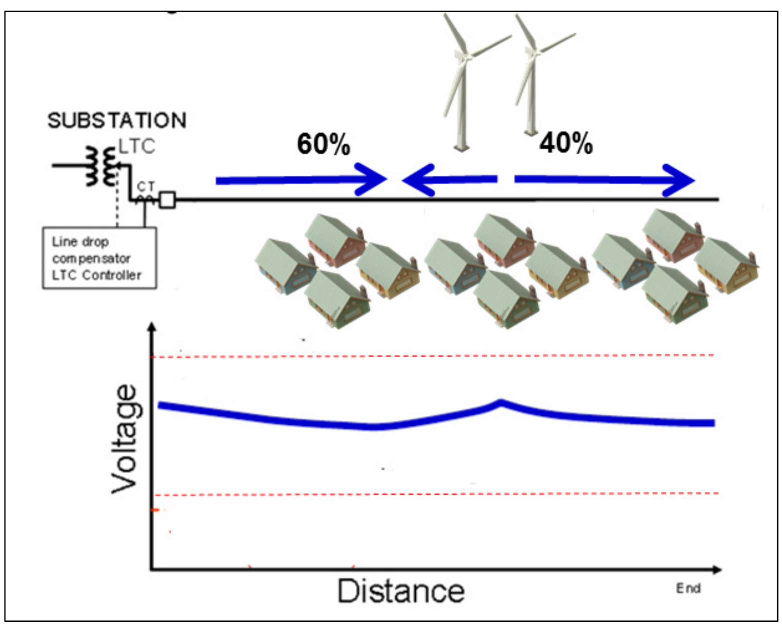


FIGURE 3-4 Voltage Profile Following LTC Operation

If the output of the wind power generators suddenly drops off to zero, then all of the electrical demand on the feeder will be fed from the substation. This results in the voltage profile shown in Figure 3-5: voltage may drop to nearly the minimum acceptable level for some customers at the end of the feeder when a significant drop-off in wind power occurs.

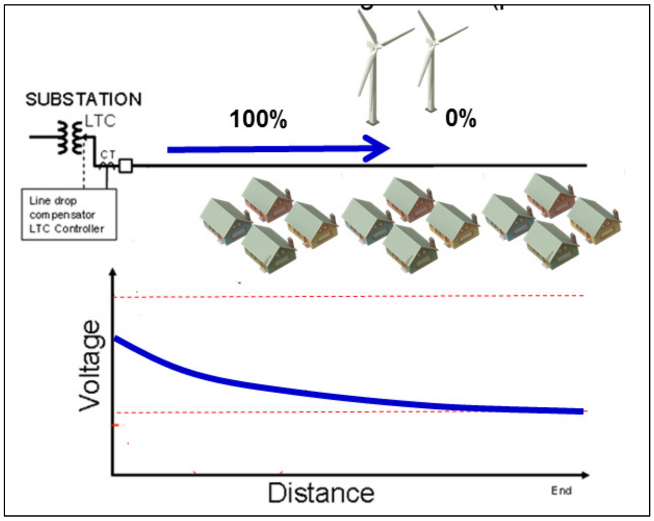


FIGURE 3-5 Voltage Profile Following Wind Power Drop-off

The LTC VR control at the substation detects the sudden change in power demand at the substation and, after a short delay, will boost the voltage, as shown in Figure 3-6.

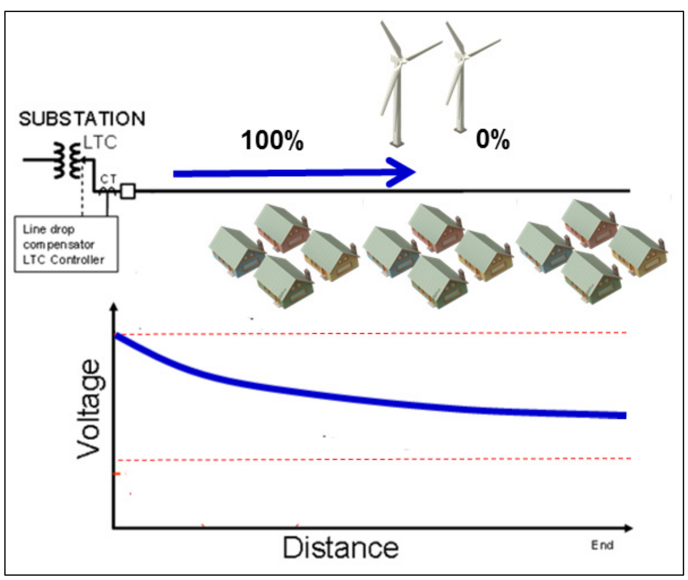


FIGURE 3-6 Voltage Restored to Normal Level by Substation LTC Operation

As illustrated in the above example, variations in the power output, which are often encountered with wind-power and solar PV generating units, can significantly increase the number of LTC operations. This increases the maintenance requirements for the substation transformer LTC and shortens its useful life.

Power output fluctuations can increase the number of operations for switched capacitor banks. When the voltage increases because of an increase in DG output, voltage-controlled switched capacitor banks may switch off; when DG output suddenly decreases, the capacitor banks may switch on. These additional switching operations increase maintenance requirements for these capacitor banks and may reduce their lifetime. In addition, increased capacitor switching may produce unacceptable levels of harmonics on the feeder.

As described above, capacitor controllers and VRs typically apply time delays (30 seconds to 2 minutes) before responding to load and voltage changes. Despite the built-in delays, there can be a greatly increased number of operations for these devices, and considerable voltage swings (up and down) may occur during built-in delay periods. Figure 3-7 depicts these potential voltage swings for a feeder with a high penetration of PV generating units.

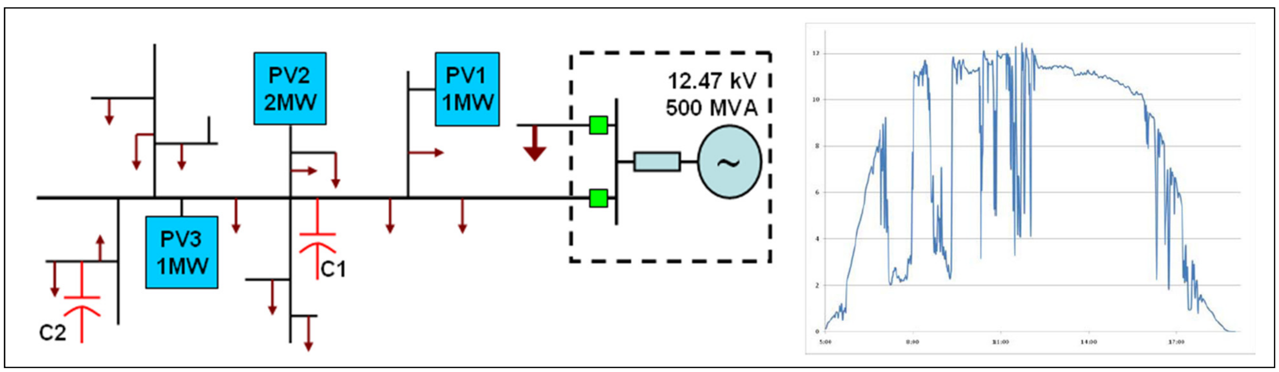
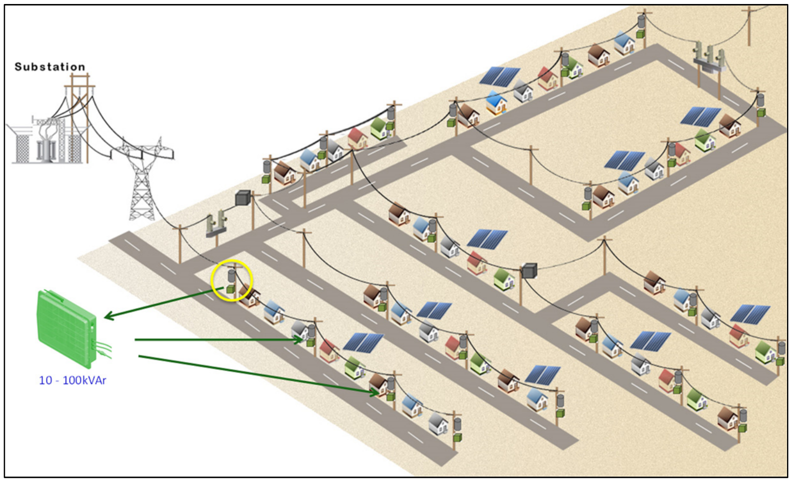


FIGURE 3-7 Voltage Fluctuations over Time with Conventional Volt-VAR Control

Use of Static VAR Sources

The dynamic voltage fluctuations described in the previous sections can be mitigated using static VAR-compensating and voltage-regulating devices that respond rapidly to voltage and power fluctuations caused by renewables without producing excessive wear on these dynamic voltage control devices and without producing harmonics that are associated with capacitor bank switching.

Low-cost reactive power injection devices that can be installed throughout the electric distribution system are currently being developed to address the voltage fluctuations associated with power sources with variable output, such as wind and solar power. Such devices inject reactive power as needed on the basis of local voltage measurements. That is, if the local voltage measurement is below a specified threshold at a given location, the static VAR source will inject VARs to boost the voltage at that location. Similarly, if the voltage at a given location is above a specified threshold, the static VAR device will act as an inductive device by absorbing reactive power in order to lower the voltage at this location. Figure 3-8 shows a portion of a distribution feeder that has numerous static VAR devices installed.

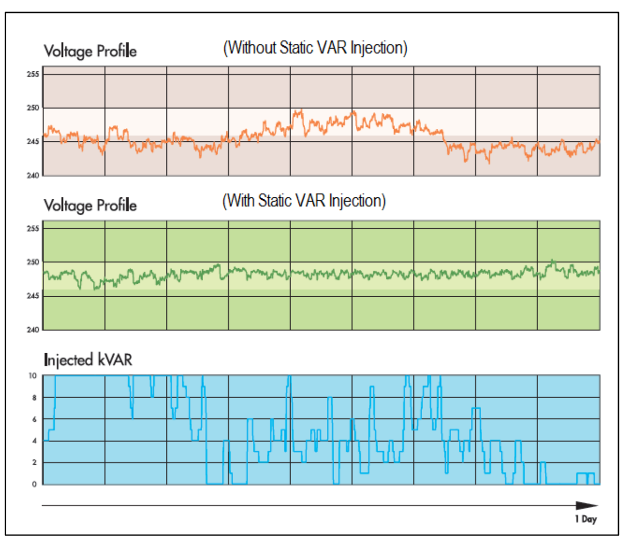


Source: Varentec

FIGURE 3-8 Static VAR Injection Devices

Chapter 5 of this report describes the use of "smart" AC inverters to accomplish the basic functions of static VAR compensators that are described above.

Figure 3-9 shows the voltage level at one point on the feeder over a 24-h period without and with static VAR injection devices installed. The voltage profile at this location is considerably smoother with the static VAR device installed.



Source: Varentec

FIGURE 3-9 Voltage Profile Without and With Static VAR Compensation

Conflicting Bus Voltage Control Requirements Imposed by DG Reverse Power

If distribution feeders with a high penetration of DERs are fed from the same substation bus as a feeder that does not have a high penetration of DERs, the situation shown in Figure 3-10 may occur, in which one feeder experiences high voltage while a feeder fed from the same bus experiences low voltage. As seen in Figure 3-10, lowering the substation bus voltage to avoid high voltage on the feeder to which the DG unit is connected (blue) may cause the non-DG feeder (green) to experience low voltage.

Possible solutions to this dilemma include installing a midline VR to either reduce voltage on the blue feeder or raise voltage on the green feeder. Alternatively, the blue feeder may be an express feeder (no customers connected) from the substation to the DG unit.

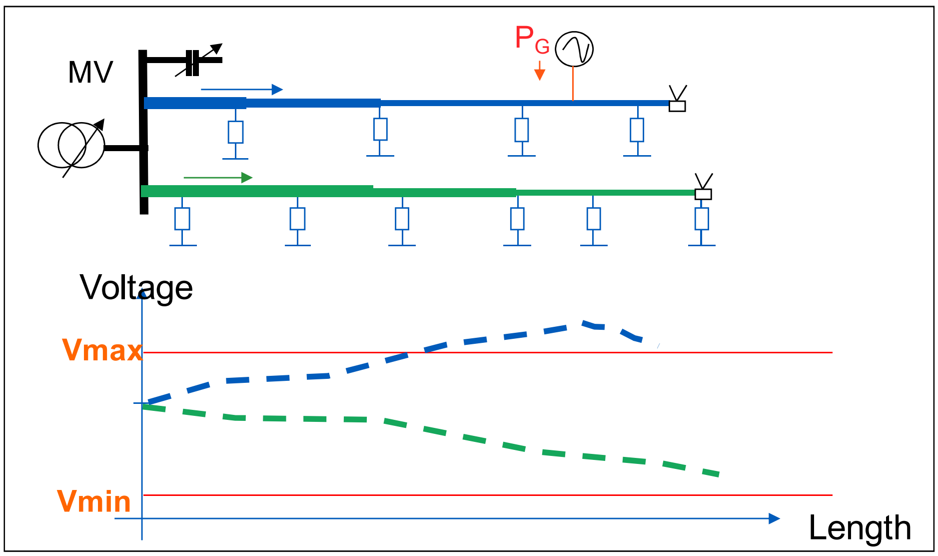


FIGURE 3-10 Conflicting Voltage Control Requirements

DMS Model-Driven Volt-VAR Control

The static VAR compensation devices described above are well-suited for managing the dynamic voltage fluctuations at any given point on the feeder. However, since these devices are stand-alone, autonomous units, they may not be well-coordinated with conventional VRs and LTCs. For example, when the output from DG resources suddenly decreases, and there is a corresponding increase in the power drawn from the substation, both the static VAR devices and the conventional Volt-VAR control devices respond as follows:

- Static VAR devices sense the drop in voltage and quickly react to boost the local voltage by injecting VARs.

- VRs (including LTCs) that include LDC sense the increase in load and (after a short time delay) change the tap position to boost the voltage for downstream loads.

- Conventional switched capacitor banks sense the change in voltage and may or may not switch on to boost the voltage, depending on their proximity to static VAR sources.

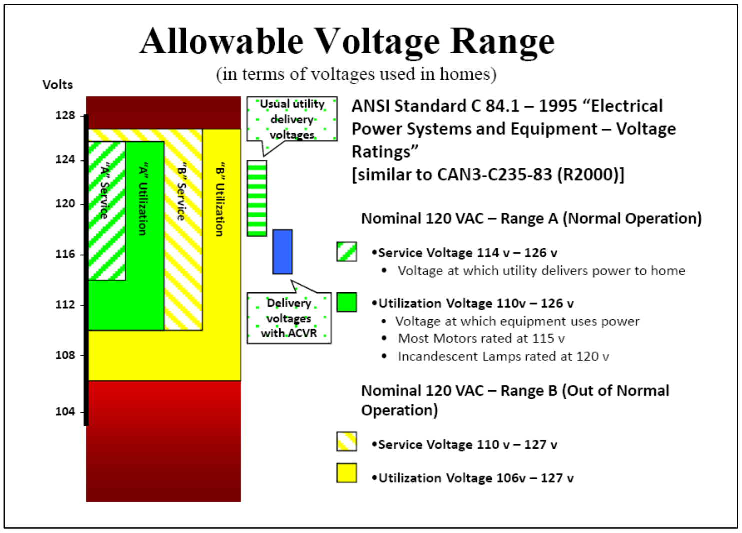
- Static VAR devices sense the change in voltage caused by VR and capacitor bank operation and may reduce the amount of injected VAR to compensate for the operation of the conventional Volt-VAR control devices.

As seen above, using independent, autonomous devices for voltage and reactive power control may not reduce the number of operations of conventional devices. Furthermore, independent device operation may not produce optimal distribution system performance under all operating conditions.

With a DMS model-driven approach to Volt-VAR control, it is possible to coordinate the operation of all voltage and VAR control devices to achieve optimal performance and fewer operations of conventional VRs and capacitor banks. The DMS as-operated model used for VVO must include suitable models of all conventional and static Volt-VAR control devices used on the feeder.

Impact of Distributed Generating Resources on Voltage Reduction Schemes

Recently, as electric utilities have been seeking to address energy efficiency and conservation portfolios, many electric distribution utilities are turning to voltage reduction as a way to satisfy energy efficiency, demand reduction, and energy conservation objectives. Voltage reduction involves operating the distribution feeder at a voltage that is in the lower portion of the acceptable voltage range (see Figure 3-11). When voltage reduction is performed at all times (24 hours per day, seven days per week), the term “conservation voltage reduction” is used, as 24-hour-per-day operation is primarily intended to promote energy conservation. If voltage reduction is used only during peak load periods for purposes of peak shaving, the term “voltage reduction” or “voltage optimization” is commonly used.



Source: Utilidata

FIGURE 3-11 Acceptable Voltage Ranges

A goal of voltage reduction is to lower the voltage as much as possible to achieve maximum benefits without violating the established low voltage limits. Careful analysis must be performed to ensure that the feeder voltage does not drop below the established minimum level following loss of DG resources.

Some utilities use automatic meter-reading systems or on-line voltage sensors to monitor the voltage at feeder extremities, where the lowest feeder voltage often exists. These sensors provide valuable feedback to ensure that voltage is not reduced below the minimum acceptable amount. The potential for voltage rise along the feeder due to the presence of DG units often results in lowest-voltage points that are not at the feeder extremities. The main reason is that in a radial network, typically the lowest voltage point occurs at the end of the feeder in the absence of DG, but the presence of DG may change this location. Therefore, a greater number of measurements are needed to provide lowest voltage feedback.

Owing to the difficulties that may be encountered when deploying voltage reduction on feeders with a high penetration of DG, a DMS model-driven VVO solution is often needed. This solution uses an as-operated model of the distribution system (including the DG resources) to accurately determine the voltage control actions that may be performed without violating high and low voltage limits.

Impact of Bi-directional Power Flow on Mid-Line Voltage Regulators

Mid-line VRs are often installed to boost the voltage if necessary on the portion of the distribution feeder that is furthest from the substation. Long feeders that have moderate to heavy loading are frequently equipped with mid-line VRs. When large DG units are located downstream of a mid-line recloser, careful analysis is needed to ensure that the VRs operate correctly under normal power flow and with power flow in the reverse direction.

This section describes some of the challenges that may be encountered when deploying mid-line VRs on feeders that have a high penetration of distributed generators.

Voltage Regulation with Power Flow in the Forward Direction

The VR must adjust its tap position as load changes to supply the desired voltage on the load side of the VR. If the load flow through the VR increases, the VR must adjust its tap position to maintain acceptable voltage downstream of the VR. Figure 3-12 depicts a feeder that is equipped with a mid-line VR. This feeder includes a backup source that may be used to supply the feeder if the normal source of supply is lost. For the initial examples discussed in this section, it is assumed that there are no large DERs on this feeder.

As seen in Figure 3-12, the normal source is supplying an average load in the forward direction of the feeder. For the average load, the mid line VR is in a neutral position which neither raises nor lowers the voltage.

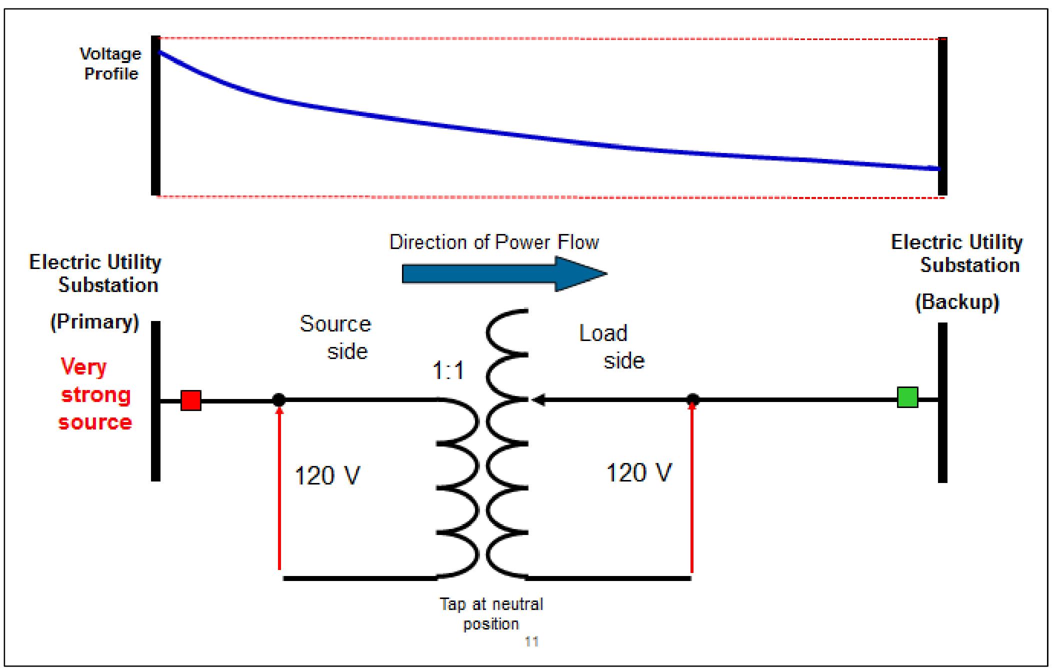
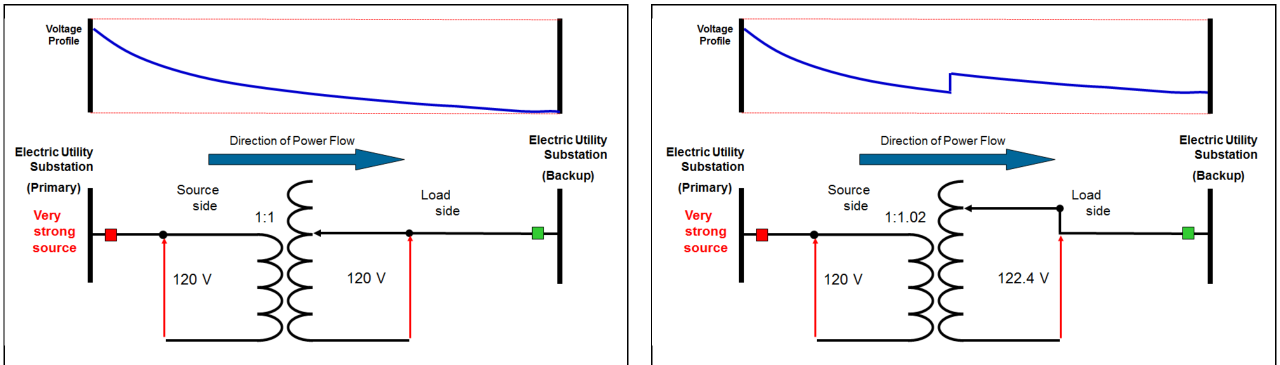


FIGURE 3-12 Voltage Regulator with Average Power Flow in Forward Direction – No DG

As the load increases in this sample case, the VR is required to boost the voltage so that voltage on the load side of the VR does not drop below the minimum acceptable value. As the load increases, the moveable tap on the load side of the VR is raised to elevate the voltage on the load side of the VR. Figure 3-13(a) shows the voltage profile before the tap position change, and Figure 3-13(b) shows the voltage profile following the tap change.



(a) Before tap position change

(b) Following tap position change

FIGURE 3-13 Voltage Regulator with Heavy Power Flow in Forward Direction – No DG

Voltage Regulation with Power Flow in the Reverse Direction Due to Feeder Reconfiguration

This section describes operation of the mid-line VR with power flow in the reverse direction. As seen in Figure 3-14, the feeder is being supplied from the backup source under average loading conditions.

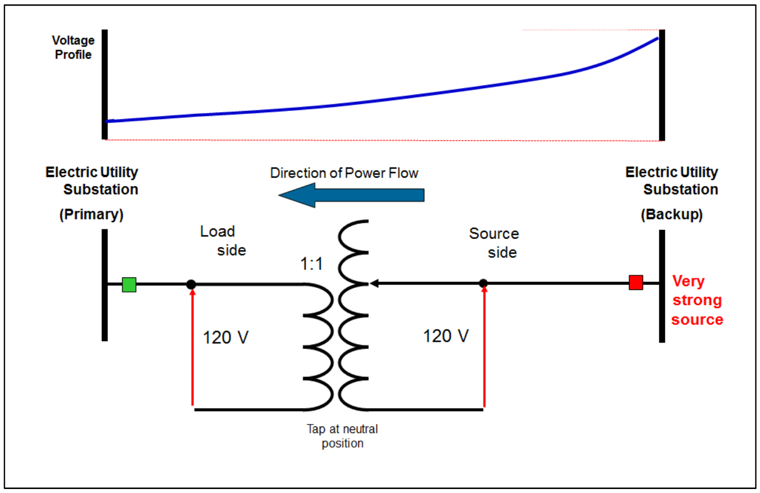
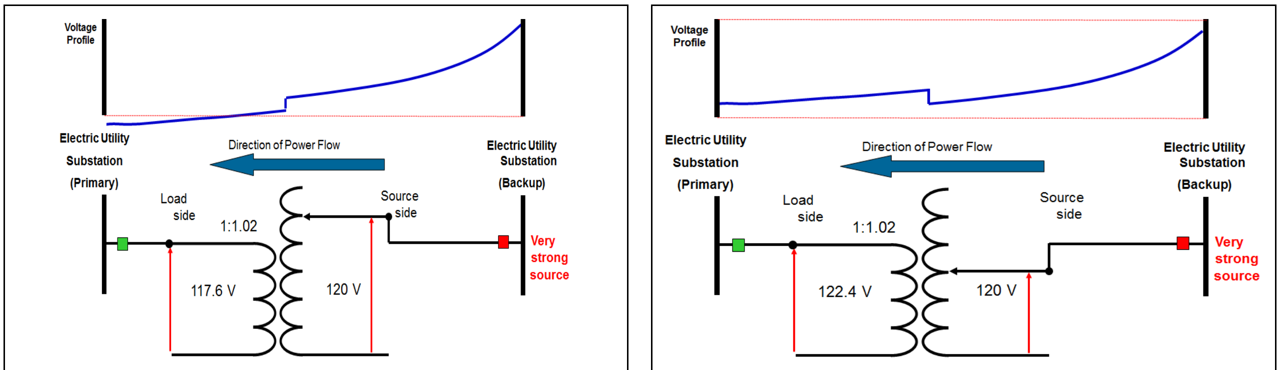


FIGURE 3-14 Voltage Regulator with Average Power Flow in Reverse Direction – No DG

When the load in the reverse direction increases, it is necessary to use the VR to elevate the voltage on the load side of the regulator. Since the moveable tap is now on the source side of the VR, the voltage control operation is somewhat different from forward-direction operation.

If the tap position is raised when load increases (as it was for power flow in the forward direction), this will lower the voltage beyond the VR, which is the opposite of the desired effect. Figure 3-15(a) depicts this situation. To elevate the voltage beyond the VR with power flow in the reverse direction, it is necessary to move the tap downwards to produce the tap ratio needed to raise the downstream voltage, as shown in Figure 3-15(b).



(a) Tap moved in upward direction

(b) Tap moved in downward direction

FIGURE 3-15 Voltage Regulator with Heavy Power Flow in Reverse Direction – No DG

The operation described above, which reverses the direction of tap movement, is commonly handled by a bi-directional VR. The bi-directional VR determines which direction to move the tap, on the basis of power flow direction.

Voltage Regulation with Power Flow in the Reverse Direction Due to Large DG Unit

In this case, the direction of power flow through the bi-directional VR is reversed because of the large power output of a DG unit located near the end of the feeder. Figure 3-16 depicts this situation.

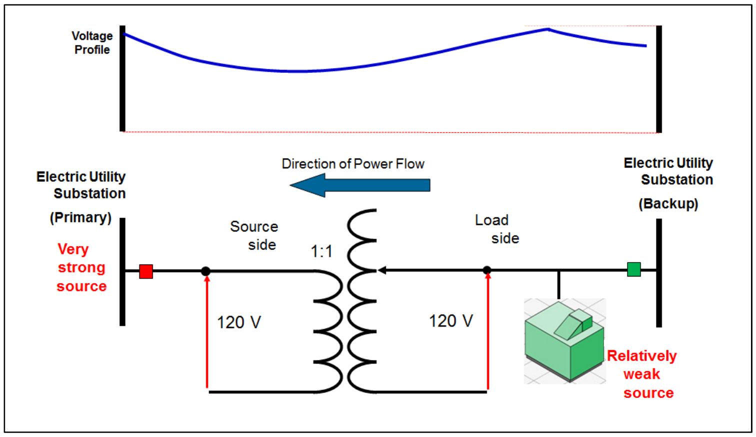


FIGURE 3-16 Average Power Flow in the Reverse Direction Due to Large DG Unit

As the load in the reverse direction increases (see Figure 3-17), the action taken by the bi-directional VR would be to move the tap in the downward direction. However, this may be the incorrect operation when reverse power flow is caused by DG output. This is because the voltage on the source side of the VR is held steady by the very strong source at the substation. So moving the tap in the downward direction has the effect of lowering the voltage on the load side (the DG side) of the VR (see Figure 3-17(a)). As seen in Figure 3-17(a), the voltage is near the minimum acceptable value following this control action. In this example, it would be better to move the tap in the upward direction, as shown in Figure 3-17(b).

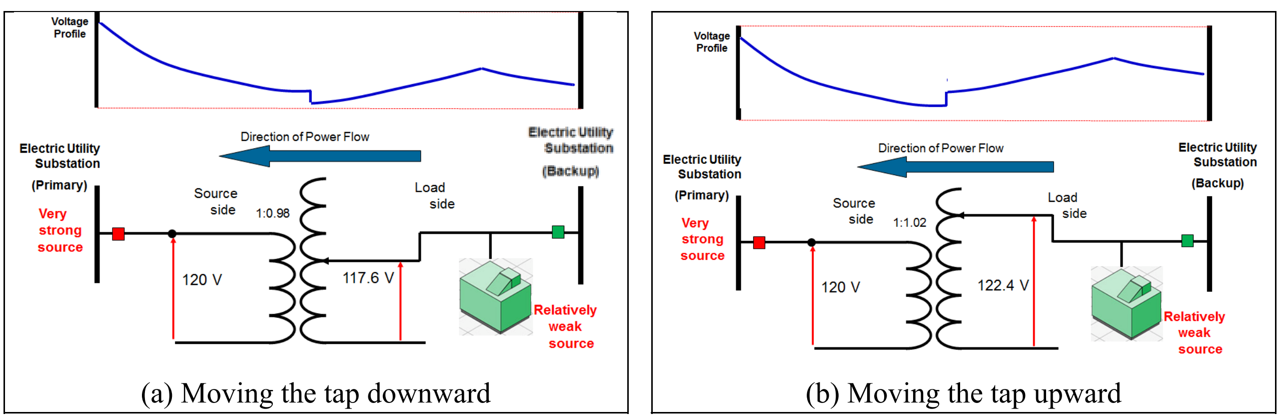


FIGURE 3-17 Load Increase in the Reverse Direction Due to Large DG Unit

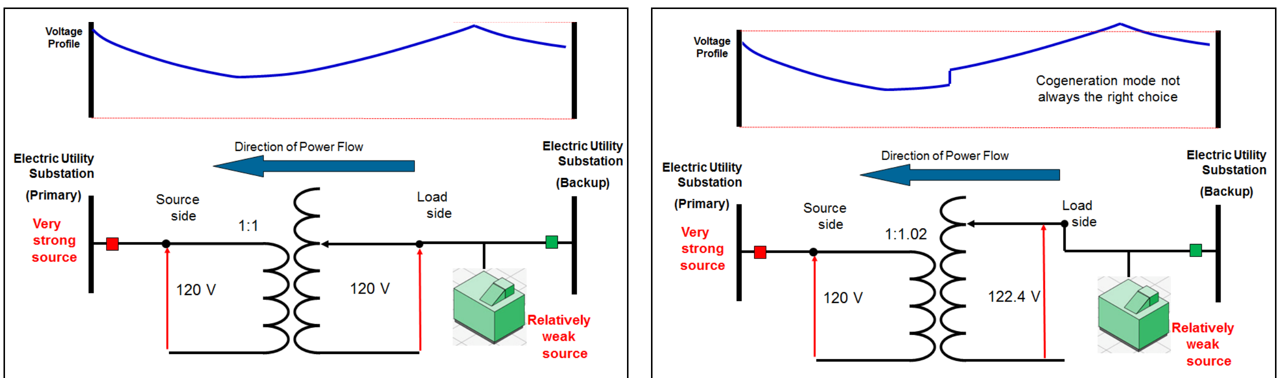
To accomplish the preferred voltage control action illustrated in Figure 3-17(b), newer bi-directional VRs include a "co-generation" mode in which the controller reverts to normal forward-direction voltage regulation when the reverse power flow through the VR is caused by DG. For proper operation, the VR must be able to distinguish between reverse power flow caused by feeder reconfiguration and reverse power flow caused by a DG unit. There are (at least) two possible ways to accomplish this:

- Determine power flow direction using both real and reactive power flow measurements. If real power flow is reversed (flow is towards the normal supply) and reactive power flow is toward the DG unit, reverse power flow is due to the DG unit. In this case, the VR should operate in co-generation mode. If real and reactive power flow is in the reverse direction, this is most likely due to feeder reconfiguration. In this case, bidirectional mode should be used.

- Determine whether the feeder has been reconfigured by comparing the open/closed status of circuit breakers that connect the normal or backup sources. If power flow is reversed and the circuit breakers are in their normal position, then reverse power flow is most likely due to a large DG unit. In this case, co-generation mode should be used. Note that this approach requires SCADA/communication facilities to acquire the current status of the circuit breakers.

The presence of a very large DG unit near the end of the feeder can impose additional complications for controlling the mid-line VR. Figure 3-18(a) shows the voltage profile during average load conditions. Figure 3-18(b) shows the voltage profile following a load increase with the VR operating in co-generation mode. As seen in Figure 3-18(b), operating in co-generation mode may cause high voltage in the vicinity of the DG unit. In this case, moving the VR tap in the downward direction would have resulted in a more desirable voltage profile.

In such cases, a DMS model-driven solution may be needed to perform the correct voltage-regulating actions under all operating conditions in the presence of large DG units.



(a) Before tap change operation

(b) Following tap change operation in co-generation mode

FIGURE 3-18 Voltage Regulation with Large DG Unit

3.2 IMPACT OF DERS ON FAULT LOCATION AND AUTOMATIC RESTORATION

Improving distribution system reliability is one of the key objectives of many electric distribution utility companies' grid modernization strategies. A growing number of utilities are implementing or planning to implement automatic restoration systems, accurate fault location schemes, and other such measures to achieve these objectives.

A high penetration of DERs may have significant impacts—both positive and negative—on the performance of such systems. This section describes ways to mitigate the adverse consequences of the presence of DERs on the performance of fault location and automatic sectionalizing systems. This section also describes ways to improve the performance of these grid modernization applications through intelligent management of DERs.

Fault Current Contributions of DERs

Some grid modernization applications, such as fault location and automatic sectionalizing, require an accurate assessment of fault current. Most systems that have been installed to date have assumed that the only significant source of fault current is the electric utility substation. If the penetration of DG resources is low, this is a reasonable assumption. However, if the penetration is high, fault current contributions from these resources can have a significant impact on the performance of some grid modernization applications.

The fault contribution from a single, small DG unit is not significant; however, the total contributions of many small units may alter the fault current level enough to cause overcurrent protection miscoordination and nuisance fuse operation, or hamper fault detection. A DG system may impact the fault coordination of a system to the point that relay setting and fuse sizing changes are required. Also, fault current contributions from DERs can reduce the accuracy of fault location calculations and may result in incorrect control actions by automatic sectionalizing systems.

Some approaches for estimating fault current contributions are discussed in a report published by NREL[2]. Some of the key conclusions follow:

- Fault current contributions of inverter-based DG units contain a "rule of thumb" of one to two times an inverter's full load current for one cycle or less.

- On the basis of lab testing, a DG unit that is connected to the electric distribution system via an inverter can deliver up to five times the rated load current, but this current decays very quickly as compared with synchronous and induction machines that can deliver six-fold current increases for several cycles. Figure 3-19 shows the fault current test result for a 1-kilowatt inverter.

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[2] J. Keller and B. Kroposki, "Understanding Fault Characteristics of Inverter-based Distributed Energy Sources," National Renewable Energy Laboratory, Golden, CO, NREL/TP-550-46698, 2010.

- One manufacturer's literature indicates that the inverter fault current is approximately 2 to 3 times the rated peak output current, with a duration time of approximately 1.1 to 4.25 milliseconds.

From the above, it is evident that the fault current contribution can be several times the maximum load current, and the inverter fault current decays rapidly (in less than one cycle).

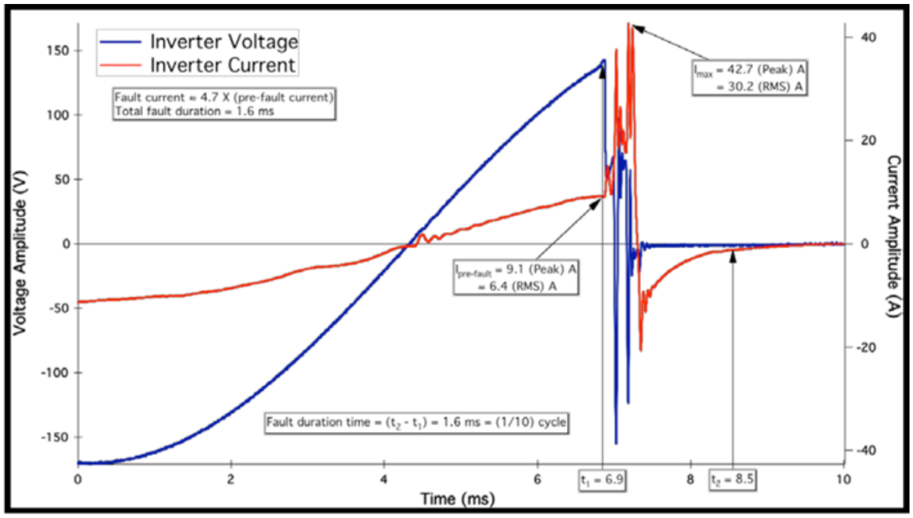


FIGURE 3-19 Fault Current Test Result for 1-kW Inverter

Predictive Fault Location Application

Modern DMS often include a Predictive Fault Location (PFL) application that can determine fault location with a higher precision than is possible with OMS prediction engines, "last-gasp" messages from AMI meters, faulted-circuit indicators (FCIs), or protective-relay "distance-to-fault" calculations. More accurate prediction of fault location will shorten the fault investigation (patrol) time, which, in turn, reduces the total restoration time and the duration of the outage experienced by the customer.

Distance-to-fault calculations performed by protective-relay IEDs compute the electrical "distance" to the fault by simple application of Ohm's law. The substation bus voltage measured while the short circuit is present is divided by the fault current magnitude to determine the electrical impedance to the fault. Dividing the impedance to the fault by the ohms per mile of the primary distribution conductors provides an approximation of the physical distance (in miles) to the fault location. Figure 3-20 and Equation 3-1 illustrate this calculation.

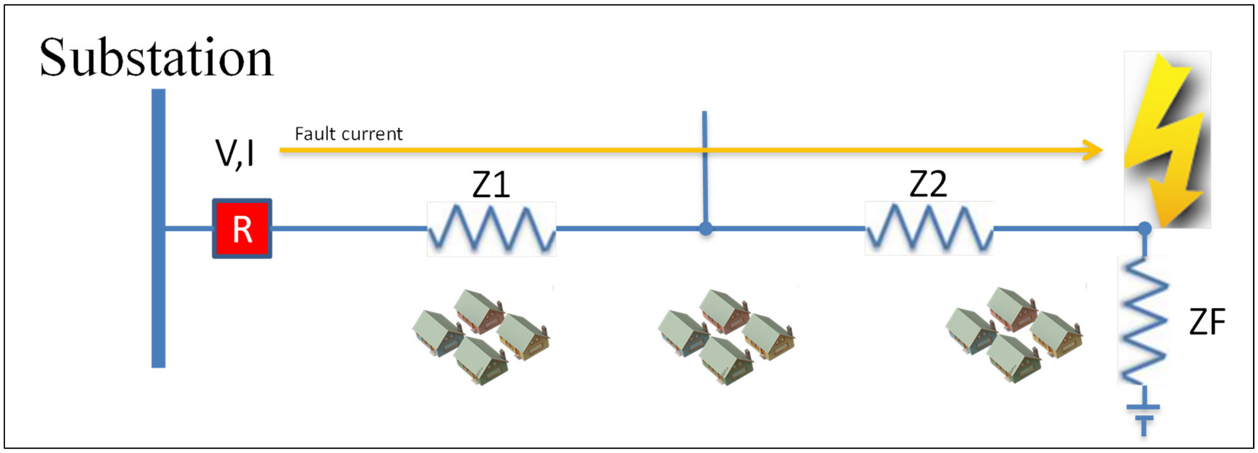


FIGURE 3-20 Distance-to-Fault Calculation – No DG

Equation 3.1 shows the electrical distance to the fault computed by the PFL application in the case pictured in Figure 3-20.

$$Electrical\ distance\ to\ fault = \frac{V}{I} = (Z1 + Z2 + ZF) \tag{3.1}$$

If there are DERs on the feeder that are capable of supplying fault current, the PFL application will identify a different electrical distance-to-fault for the exact same fault. Figure 3-21 and Equation 3.2 illustrate the calculations for a feeder with DG included.

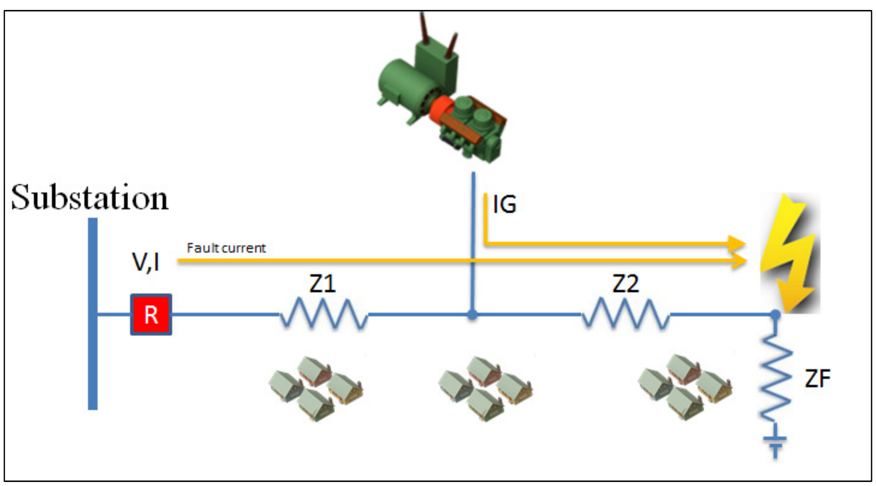


FIGURE 3-21 Distance-to-Fault Calculation – DG Present

The voltage (V) and the current (I) measured at the substation bus will be slightly different when there is a fault current contribution from DG units located out on the feeder. Equation 3-2 shows how the fault current contribution from DG units on the line affects the distance-to-fault calculations performed by the protective-relay IEDs. As can be seen in this equation, the predicted distance-to-fault with DG present is greater than the actual distance-to-fault. It can also be seen that the larger the fault current contribution from the DG unit, the greater the error.

$$Electrical\ distance\ to\ fault = \frac{V}{I} = (Z1 + Z2 + ZF) + \frac{IG}{I} * \ (Z2 + ZF) \qquad (3.2)$$

To improve the distance-to-fault calculation, the DMS PFL application uses the actual as-operated model of the distribution system to compute the estimated distance-to-fault. The as-operated model accounts for the fault current contribution from DG units located out on the feeder.

Impact on Fault Location, Isolation and Service Restoration

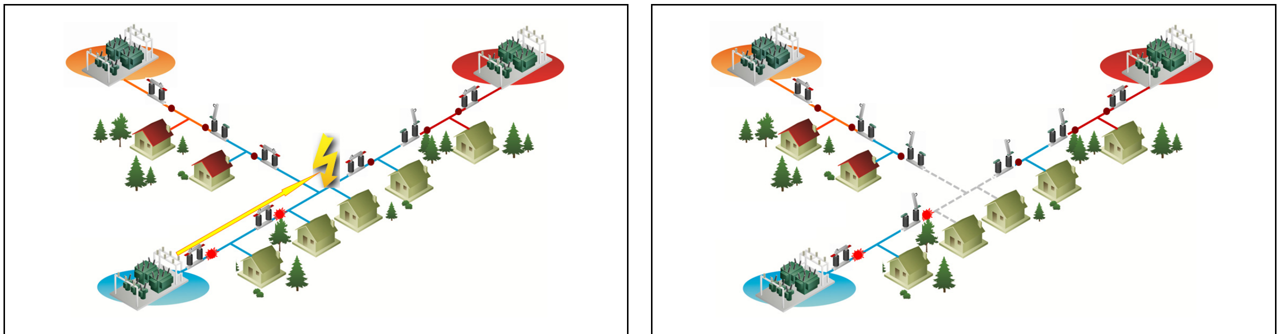
The Fault Location Isolation and Service Restoration (FLISR) application function automatically detects that a fault has occurred, locates the fault (between two medium-voltage switches), issues control commands to open the switches that bound the damaged area to isolate the damaged section of the feeder, and then closes other switches (where possible) to restore service to healthy sections of the feeder. The current state of the art allows all of these actions to be completed without manual intervention (via fully automatic control).

There are several ways in which DERs can have an impact on FLISR operation. These impacts are described in the following sections.

Fault Location and Isolation

Faulted Circuit Indicators (FCIs) play an essential role in the fault location process. FCIs indicate whether fault current has recently passed through the device, indicating that there is a short circuit somewhere downstream of the FCI (further from the substation). FCIs are commonly used by first responders who are tasked with initial fault investigation, location, and damage assessment. FCIs and functionally equivalent Fault Detectors are also used by FLISR to locate the fault between two switches so that the faulted portion of the feeder can be automatically isolated.

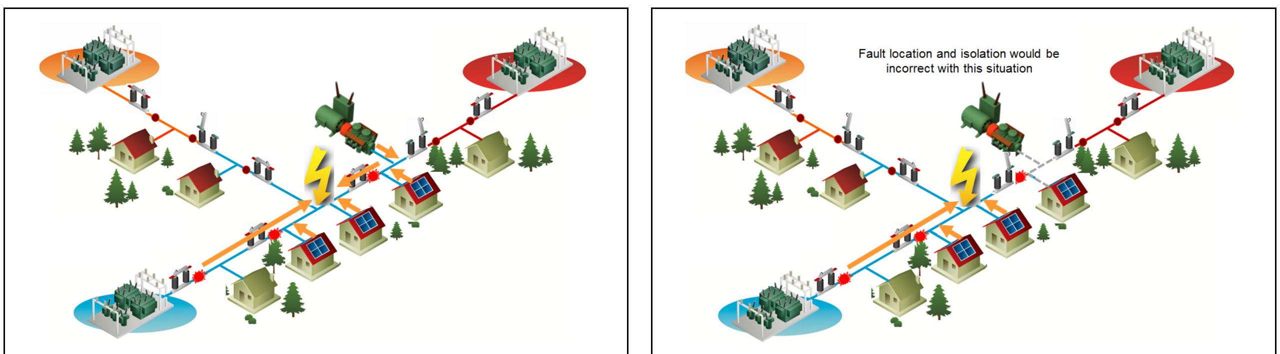
Figure 3-22 shows a sample feeder with FCIs that support automatic FLISR functionality. If a fault occurs in the middle section of the feeder, fault current passes through only the first two FCIs, as shown in Figure 3-22(a). The remaining FCIs do not see fault current. The faulted feeder section is bounded by one FCI that has seen the fault and one or more FCIs that have not seen the fault. This information is used to isolate the faulted section, as shown in Figure 3-22(b).



(a) Fault Detection and Location (b) Fault Isolation

FIGURE 3-22 FLISR Operation with No DG

FLISR logic works well if there is only one source of fault current on the feeder, as is the case with radial distribution feeders that do not have any DG units. However, if more than one source of fault current (such as a DG unit) is present on the feeder, it is possible that the faulted feeder section will be fed from multiple directions, as shown in Figure 3-23(a). This may result in incorrect fault location and isolation (see Figure 3-23(b)), which may lead to feeder lockout during automatic service restoration activities. Numerous utilities have discovered that existing FLISR systems have operated incorrectly as the penetration of DG has increased.



(a) Fault Detection and Location (b) Fault Isolation (Incorrect)

FIGURE 3-23 FLISR Operation with DG Present

One possible solution to this problem is to install directional FCIs that operate on the basis of fault magnitude and direction. This functionality can also be achieved using directional overcurrent relays out on the feeder that may serve as directional fault detectors for the FLISR function. With directional fault detectors, the faulted feeder section is bounded by one or more directional FCIs that detected fault current flow into the segment and one or more directional FCIs that did not see a fault.

"Net Load" Problem with DG Present

Before performing any load transfers to restore service to customers that are located downstream of the faulted feeder section, FLISR must verify that the load being transferred does not exceed the available spare capacity on the backup source. Normally, the FLISR application tracks the total load on each section prior to the fault by determining the net load flowing into the feeder section. If the net load does not exceed the available spare capacity on the backup feeder, then downstream restoration will occur.

One issue that is often overlooked is that any DG that is connected to the feeder section will drop off-line following the fault and will not be reconnected until at least five seconds after normal primary voltage is restored. As a result, the net load that must be transferred is actually greater than the pre-fault net load determined by FLISR, and may in fact exceed the available spare capacity on the backup feeder. Figure 3-24 depicts this situation.

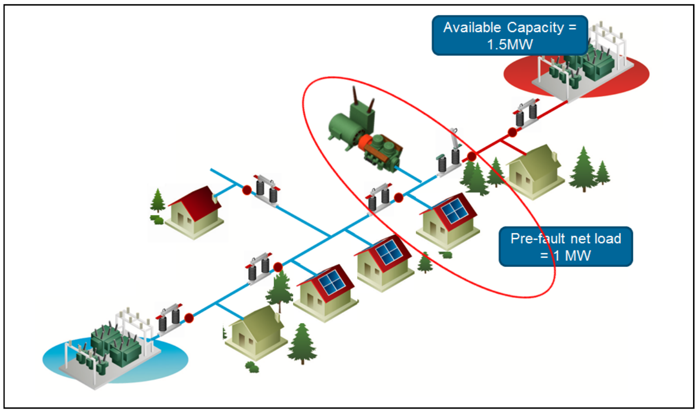
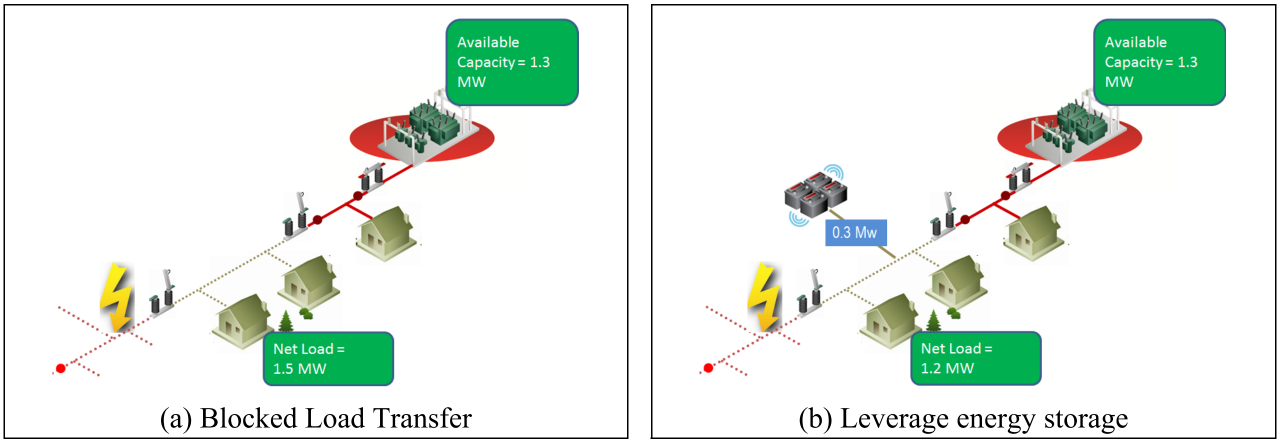


FIGURE 3-24 Net Load Problem with DERs

Using Energy Storage to Avoid Blocked Load Transfers

Service restoration is often blocked owing to lack of spare capacity on available backup power sources. This is an especially common occurrence for heavily loaded feeders. Possible solutions to this problem include dividing the feeder into smaller sections with additional automated switches and connecting more backup sources to the feeder. This can be a very expensive solution to the problem.

Another possible approach is to leverage existing energy storage facilities (including community energy storage) to supply a portion of the load, thus reducing the net load that needs to be transferred. Figure 3-25 illustrates this method.



(a) Blocked Load Transfer

(b) Leverage energy storage

FIGURE 3-25 Avoiding Blocked Load Transfers Using Energy Storage

4 DISTRIBUTED ENERGY RESOURCE MANAGEMENT SYSTEMS

Previous chapters of this report discussed the potential impacts of DERs on conventional voltage regulation and protection systems and ways to mitigate these impacts. This chapter discusses using electric utility-owned monitoring and control systems, such as a DMS, to manage the DERs themselves to improve distribution system reliability, efficiency and performance. These DER monitoring and control systems are collectively referred to in this report as a DERMS.

Note that the term "DERMS" has been adopted by several DMS vendors to refer to specific product offerings for managing DERs. However, in this report, "DERMS" is used in a generic sense, and does not refer to any particular vendor's product offering.

The topics discussed in this chapter include:

- DERMS components and architecture
- Energy management
- DER firming and VPPs
- Islanding (microgrids)

The DERMS software is used to monitor and control DERs. The software will provide accurate generation models for each type of DER and field validation of DER operation. Integrated with the DMS, the DERMS will enable dynamic adequacy assessment for intermittent generation on the grid along with forecasts of output for each intermittent generation resource. Initial control of DER devices will be disconnect/connect only, to ensure the security of the grid. In the future, islanding and microgrid control functions can be added to the DERMS.

Integrating a DERMS with the DMS will allow the DMS to have a full view of all DER assets connected to the grid. The DMS will utilize asset information (on/off, output level, etc.) to determine the best method of control of other Volt-VAR resources to optimize the grid. In the event of a fault, the DMS will ensure that all DG resources are disconnected until after the feeders are reconfigured and service is restored. Then the DMS will command the DG resources to return to normal operation. In the future, the DMS will be able to optimize dispatching of DG resources for the utilities' benefit and island operation of the grid utilizing all available DG resources in emergency conditions.

The DERMS software integrates various forms of distributed energy with a decentralized controls strategy and makes innovative capability available to the system operator in the form of ancillary services and local power management functions, such as VPP operation, peak load management with DER, intermittency management, and islanding.

4.1 DERMS ARCHITECTURE

This section describes the general architecture and major components required for implementing a DERMS. As seen later in this chapter, the general DERMS architecture is consistent with and compatible with the major DER integration applications, such as DER energy management, DER firming and smoothing, and island microgrid operation.

The DERMS architecture is usually based upon a layered strategy for enabling a distributed wide-area controls- and services-based model for accessing capabilities and dispatch of DERs such as wind and other renewable sources, conventional generation, energy storage, and controllable loads (a.k.a. demand response). Figure 4-1 depicts the configuration of the components that comprise the DERMS: the DERMS uses a “layered” architecture that includes three main levels, as described in the following sections.

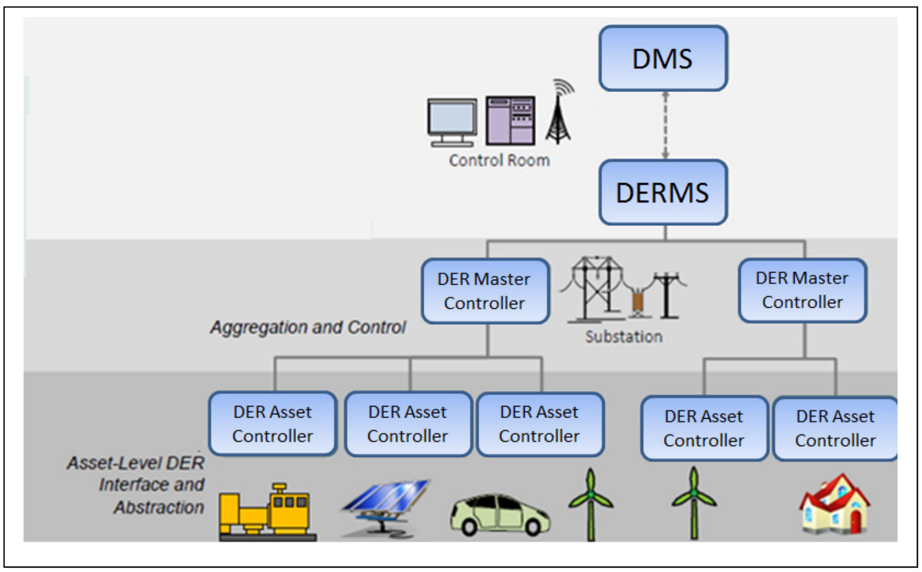


FIGURE 4-1 DERMS General Architecture

DER Asset Level

This level includes the facilities needed to control an individual DER based on the strategy established by the DERMS higher-level components. Each DER site is equipped with programmable remote terminal units that act as local controllers (LCs) for the associated DER. The DER asset-level controller resides close to the DER and speaks “native” DER protocols. Owing to the close proximity of the DER assets, the asset controller is able to execute fast control loops in the range of 1 millisecond to 100 milliseconds.

The DER asset-level controller should be able to expose all functionality of the DER, including enabling/disabling, active and reactive power control, ramp rates, and other features of the DER, to higher levels of the DERMS architecture.

Master DER Controller Level

The master DER controller manages the operation of all DERs that are connected to a specified feeder or substation as needed to accomplish the "system-level" operating objectives established by the Central Management System. The master controller is primarily used for carrying out distributed control and aggregation functions. This controller may be a ruggedized PC that is commonly installed at an electric utility substation. Each master controller is used to manage the LCs that are normally connected to feeders that are connected to that substation.

Supervisory control functions initiated by the master controllers are suitable for executing medium-speed control loops in the range of 100 milliseconds to 1 second.

Enterprise Level

Enterprise level functionality typically resides at the head end of the system and provides network power management functions. DERMS components at the enterprise level establish the overall operating strategy for all DERs on the basis of overall system needs. This includes all facilities to enable the distribution system operator to monitor and control the DERs that are connected to the distribution system. The DERMS enterprise-level components are most commonly integrated with the electric utility's DMS.

The enterprise level aggregates all generation, storage, and demand resources and provides a single controllable interface for distribution network operators. This enables "aggregated virtual generators" or microgrids capable of rapidly islanding a facility from the power grid for reliability or security purposes and gaining active control over power import and export.

The enterprise-level facilities are able to initiate some control actions required to operate the DERs. However, these control actions are limited to application functions that do not require very low latency. In most cases, the supervisory control loops are in the range of 1 second to 100 seconds. This level of latency is well suited for downloading set points and operating strategy to the master DER controllers, but it is insufficient for balancing microgrid load and generation or providing high-speed response to electric transients on the feeders.

The DERMS enterprise-level software should include accurate dynamic models for each specific type of DER. This enables the DMS application software (e.g., on-line power flow) to determine the impact of DERs on distribution system operation and enables future active control of the DERs. The enterprise-level models of DERs will also enable the DERMS to forecast the operations of intermittent DERS (such as wind and solar power) under normal and emergency conditions. The DER dynamic models will also improve the ability of the electric distribution utility to plan, monitor and control the operation of distribution systems that may include a high penetration of DERs.

The DERMS will enable the distribution system operators to have a full view of all DER assets connected to the grid. In the event of a fault, the DMS will ensure that all DG resources are disconnected until after the circuit is reconfigured and service restored. Then, the DMS/DERMS will command the DG resources to return to normal operation. In the future, the DMS will be able to optimize dispatching of DG resources for the electric utility's benefit. The system will also support island operation (microgrids) utilizing available DG resources under emergency conditions.

System operating objectives developed at the central management level are passed to multiple master DER controllers, which in turn download specific operating set points to the individual DERs.

4.2 ENERGY MANAGEMENT FUNCTIONS

The DMS may be used to manage the DERs, including generation, storage, and load of all entities within a distribution feeder or substation. By deploying DERMS functionality, electric distribution utilities will benefit from the ability to control the dynamic exchange of power between the DERs and the bulk grid over the interconnecting tie-lines (e.g., the feeder connection between the distribution system and the bulk power grid).

The DERMS is able to manage the feeder power flow and voltage at the point of interconnection (POI) to meet the needs of the system operator. Control is implemented by coordinating the applicable DERs, allowing the collection of these assets to appear as one aggregated dispatchable producing or consuming entity connected to the bulk grid. This section outlines the reactive and active power controls required for this capability.

Reactive Power and Voltage Control

The primary functions of Reactive Power Control are voltage regulation and power factor control at the POI. Capabilities include voltage set point, steady-state voltage response, and transient VAR response. The Reactive Power Controller can receive either an external remote reactive power command or a voltage command from the DMS or distribution system operator. The local controls ultimately are responsible for regulating the VARs locally in each component.

The controller compares the VAR output at the POI and adjusts the reactive power command to obtain the desired system voltage.

Active Power Control

The primary function of Active Power Control (APC) is to control steady-state and transient active power flow at the POI. The objectives of APC include:

- Enforcing power limits at the POI
- Enforcing ramp-rate limits at the POI
- Responding to system frequency excursions

The parallel control loops for power limit, ramp rate limit, and frequency limit will not be activated if all the operating conditions are within allowable limits. However, if any one of the controls is triggered, an adjustment command is generated with the intent to bring the system back to the normal operating condition. In most cases, power limit control will have the highest priority and ramp rate limit control the lowest.

The total adjustment command is allocated among the available controllable assets on the basis of their participation factor, assigned by the optimal dispatch control.

4.3 DER FIRMING AND VIRTUAL POWER PLANTS

DER "firming" is the organization of individual DERs into an operational entity whose purpose is to make the energy of the aggregator available to the grid. Realizing extensive benefits requires organizing DER into aggregations that are large enough and sufficiently responsive to changing system needs to align with the requirements of the operation of the larger, overarching electricity grid. This result requires the integration of smaller resources into larger, but not necessary very large, aggregations or resource communities consistent with grid scale and scope requirements.

There are a number of technologies and tools that support the firming of DERs for service delivery and program/market participation. They include communications-enabled devices and assets, system-integrated electronics, software systems and applications, and control and management methodologies. These technologies and tools are well aligned with the concept of the DERMS architecture and functionality.

Local Controllers and Grid Interconnection

A low-cost, durable and reliable electronic interface is necessary on the DER side for the proper interconnection of DERs with both utility and customer systems. Power electronics are switching devices that control and convert electrical power flow from one form to another (AC to DC, primarily). They include a control system, semi-conductor switches, thermal devices, protection devices, magnetic devices such as transformers and filters, and DC and AC disconnects and enclosures.

Power electronics are critical to firming DERs because they convert source power into a format that is grid-compatible so that energy from the resources most efficiently interacts with the grid system, optimizing value and minimizing loss/negative factors.

The grid interconnection is comprised of hardware, software and power electronics to ensure safe and efficient interoperation of the DERs with the power grid. The grid interconnect both facilitates the physical integration of energy from these resources and buffers the grid from any potential adverse impacts from the interconnected devices. Advanced sensors, controls and communications equipment are essential for optimizing operation and diagnosing DER status so that the system can be controlled on-site or remotely. The grid interconnect is critical to firming

DERs because it ensures that issues such as harmonics, voltage irregularities, and other potentially harmful impacts are adequately managed at the point of delivery.

Communication Facilities

To a large extent, the firmness of DERs is dependent upon the degree to which they can be integrated at the system level through interactive monitoring, measurement and control. A central component of this integration is the communications capability between the DER interface and the grid operator that is necessary to support DER control interfaces. The more granular the monitoring and control capability, the more closely system attributes (DER capability characteristics) can be monitored and controlled, and consequently the more flexible the resource will be in meeting the diverse needs of the energy delivery system.

Energy Storage

Cost-effective and efficient energy storage devices may be critical components in enhancing DER reliability. Coupled with renewable and natural gas generation systems, power conditioning equipment, and remote power systems, energy storage devices can be used to provide safe and reliable power for on- and off-grid applications to support peak-shaving strategies for improved asset utilization, power quality, and maintenance.

Energy storage is a valuable firming tool, as it can store power that is otherwise not available for serving system needs that require firm delivery (for example, energy generated by intermittent resources such as wind), condition the power, and make it available for firm delivery at a more beneficial time.

Sensors and Controls

Advanced sensors are needed for the safe and efficient integration of DERs into the power system. These sensors measure various DER performance parameters such as temperature, pressure, efficiency, emissions, costs and other factors. Sensors and control systems can also be harnessed to the measurement of power output, revenue metering, and conveyance of real-time price signals, data acquisition, and communications. Real-time data communications open the way for adaptive control, which involves measuring some aspect of the system condition and defining actions to meet the service needs dynamically. This control supports the ability to match the variable needs of the energy delivery system with the variable capabilities of integrated DERs. These tools will enable remote dispatch and control, a cost-effective means for aggregating distributed power supplies or demand management (direct load control) devices into larger resources to support grid operations, thereby enhancing the efficiency and reliability of the energy delivery system.

Coordination with Current Dispatch Systems

While electric demand is instantaneous, the decision to commit the resources needed to meet forecast demand occurs in advance. Using integrated DERs as a firm, dispatchable resource to supplant traditional central/thermal generation requires the DER to be coordinated in a manner that is compatible with the overall unit-commitment and/or dispatch context. Moreover, as DER generation and control technologies improve, it is possible that DERs will start to be included in the base load calculation as a substitute for traditional base load generation. There may be planning scenarios where this approach is attractive—for example, using load reduction to reduce the shoulders from a load curve during non-peak operational periods could allow a distribution company to forego the purchase of an incremental load block for which it only has an active load requirement of 10%. As these scenarios and services are developed, utility personnel will likely be asked to analyze the comparative value of DERs in their Integrated Resource Plans.

Utility operations span several time scales. Unit commitment is done in several steps, beginning the day ahead to establish an "economic merit order" unit commitment schedule, then 90 minutes, five minutes, and five seconds ahead, with each step adjusting the commitment schedule on the basis of current information on demand and unit availability. Within these time frames, decisions must be made regarding which generating units to start so that they are available when needed. In a traditional dispatch curve, the unit-commitment decisions are made well in advance of the time the generator might be needed because of the relatively long time required to ramp up and ramp down some types of generators.

4.4 MICROGRIDS

One of the best examples of managing DERs in a manner that improves the overall performance of the electric distribution system is the microgrid. The microgrid concept is not new. For years, chemical plants, refineries, military installations, and other large facilities have had the ability to generate and manage their own electricity needs while remaining connected to centrally located generation for supplemental needs. Electric utilities have recently deployed microgrids to serve portions of their network where the loss of a single line would result in a lengthy outage for all customers served via a damaged circuit. With a microgrid, the utility may continue to serve the affected customers by disconnecting the damaged circuit and using local generating resources to supply power to some or all of the customers using local generation and energy storage devices.

There is considerable interest in using microgrids to maintain power to as many customers as possible following a "super storm" such as Hurricane Sandy, which caused extensive damage to the electric utilities' power delivery infrastructure, resulting in long outages for a large number of customers. Under such circumstances, microgrids can serve customers (especially critical customers like emergency authorities, hospitals, and even gas stations) in islanded operations, matching DERs with loads.

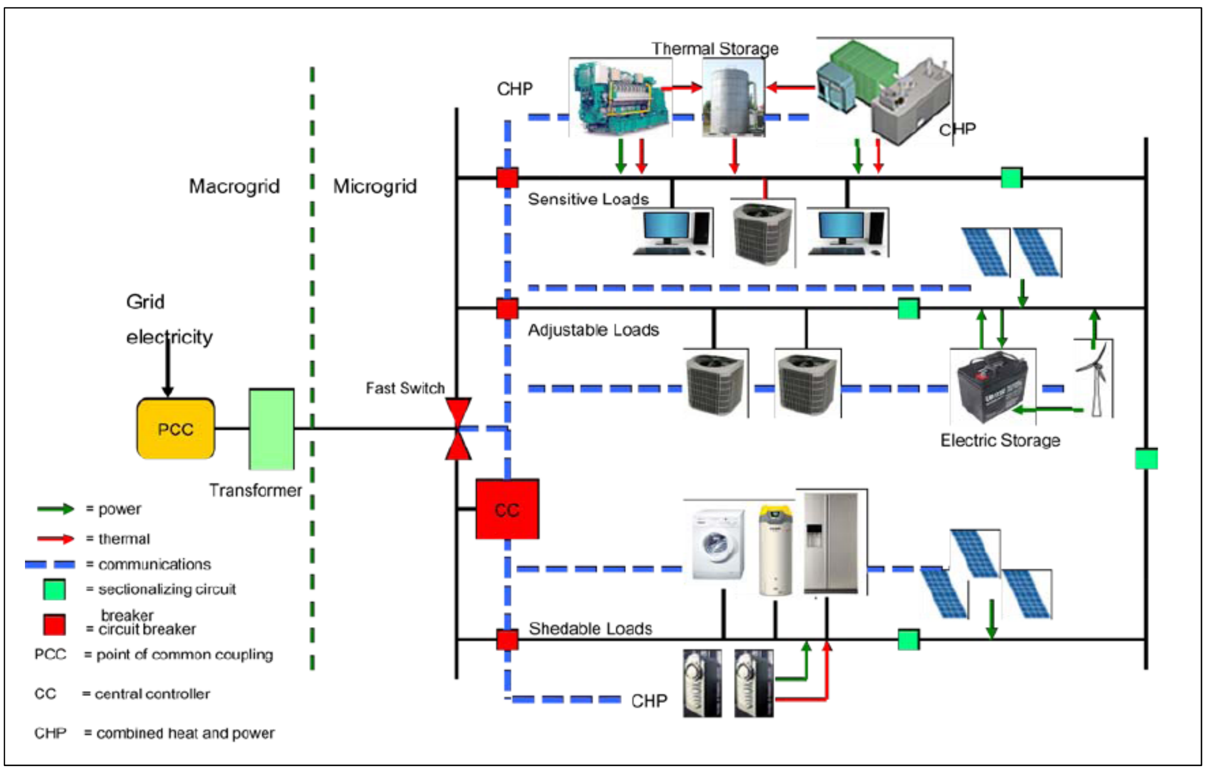
During emergency situations, DG offers benefits to both generation owners and customers. Microgrids can provide power services to consumers when the larger grid system fails. Other business reasons for implementing the microgrid concept include the following:

- Reducing total electrical losses that occur in the power delivery portion of the power grid by supplying a portion of the load from generators located in close proximity to the load.

- Deferring (or even eliminating) the capital expense needed to upgrade distribution-level facilities (wires, transformers, etc.) to accommodate increasing demand.

- "Enabling" the introduction of DERs into the distribution grid.

Figure 4-2 depicts a typical microgrid design, which contains the elements found in most microgrids.



Source: "Microgrids: An Assessment of the Value, Opportunities and Barriers to Deployment in New York State," NYSERDA, September 2010

FIGURE 4-2 Sample Physical Microgrid Schematic

Microgrid Monitoring and Control Architecture

The microgrid uses a multi-level control strategy that is consistent with the DERMS architecture described in a previous section of this chapter. The microgrid control hierarchy includes asset-level controllers (a.k.a. micro-controllers), asset management controllers (the Central Controller [CC] in Figure 4-2), and a central management controller or DMS. The role of each controller is summarized in the sections below.

Local Controllers

The operation and management of the individual DERs are controlled and coordinated via local asset or micro-source controllers, which are sited with generation, storage, and load control devices connected to the microgrid. The LCs manage the operation of individual DERs and controllable loads within a microgrid. In a centralized mode of control, the LCs receive their commands from the Microgrid Central Controller (MCC) in the form of control set points via a communication link.

Microgrid Central Controller

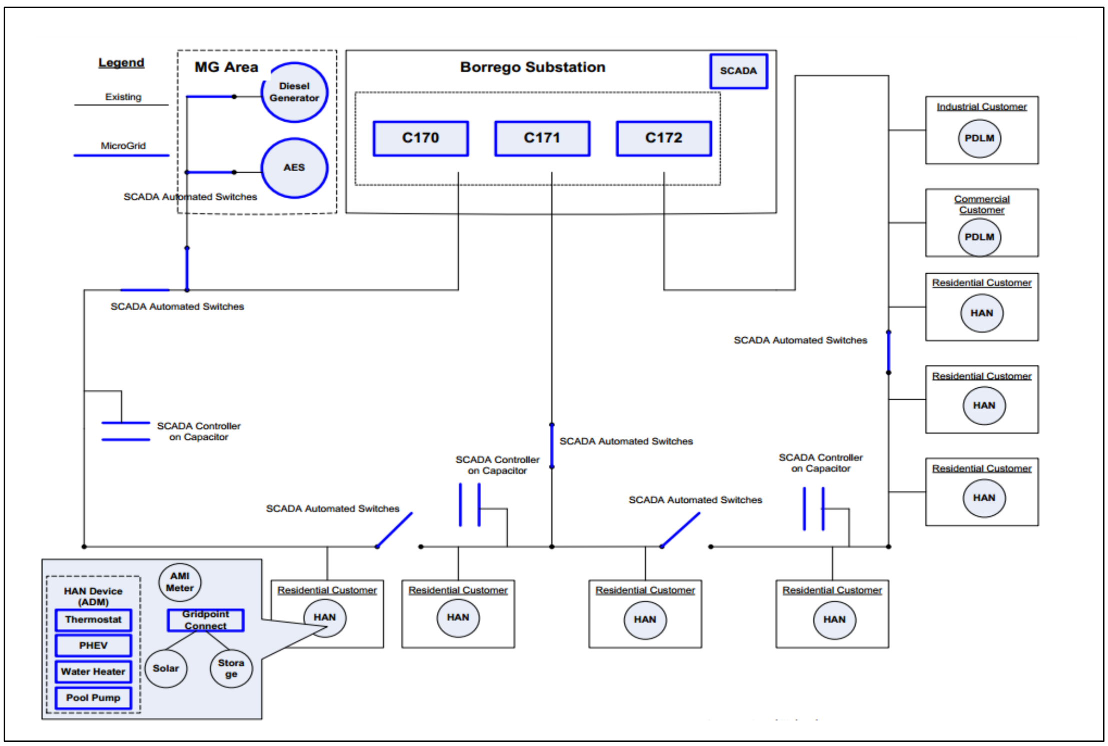
Microgrids require operating systems that are capable of managing loads and the operation of generators as well as determining when and how to switch between grid-connected and islanded operating modes. In the islanded mode of operation, the DERs are mainly controlled to regulate the microgrid voltage magnitude and frequency. Consequently, the MCC can specify the commands for steady-state voltage magnitude and frequencies of the DERs, ensuring the well-being of the loads or safe reconnection of the microgrid to the host grid once the operating mode is to be switched to the grid-connected mode. Further, the supervisory control can shed loads in the islanded mode of operation, depending on load criteria, microgrid energy reserves, or other considerations.

The MCC includes monitoring and control software, which usually includes functions like SCADA, energy management, generator and load management, system reconfiguration and black start after a fault, system efficiency monitoring, carbon dioxide contribution analysis, system health monitoring, and others. The microgrid energy manager generally has a communication link to all major generators and loads within the system. In addition, it may receive precise weather forecast data from a professional weather service for all locations of renewable power generators inside the microgrid. Merging this information with the physical characteristics of the generators, the microgrid energy manager can predict the available amount of renewable power generation for the near future. This information helps plan the utilization rate of the fossil-fueled generators within the microgrid.

The asset management controllers handle the influx of load and bi-directional flows of electricity. The micro-source controllers (also called “slave” controllers because they are subservient to the MCC) handle the operating functions of the local generators and storage devices (i.e., DERs) as well as the response of controllable loads and switches or breakers to local conditions. Micro-source controllers execute the response of DERs to real-time changes in supply and demand as well as voltage, current, power, and reactive power states.

The installation of SCADA at critical points on the microgrid distribution system (e.g., all circuit breakers and switches) can provide the necessary monitoring, communications, and control capabilities for distribution automation. On a microgrid, SCADA is deployed to monitor and control electric and/or heat generation, storage devices, distribution equipment, and other ancillary services such as capacitors and other VAR-control devices. Figure 4-3 provides one example of how SCADA is being incorporated by SDG&E into its microgrid system.

A key challenge of microgrids is to ensure stable operation during faults and various network disturbances. Transitions from interconnected to islanded mode of operation are likely to cause large mismatches between generation and loads, posing a severe frequency and voltage control problem. Storage technologies, such as batteries, ultra-capacitors and flywheels, may become important components of microgrids, with the duty to provide stable operation of the network during network disturbances. Maintaining stability and power quality in the islanded mode of operation requires the development of sophisticated control strategies and needs to include both generation and demand sides. Executing these functions is a key requirement for the MCC.



Source: SDG&E RDSI Project Overview, DOE Peer Review, November 3, 2010

FIGURE 4-3 Borrego Substation Conceptual Circuit Illustration

Microgrid Management System

The Microgrid Management System (MMS) provides executive control functions over aggregate system operation, including the individual micro-source controllers, DERs, and power conditioning equipment. This functionality is often incorporated into the DMS. The MMS ensures that power quality and reliability on the microgrid are maintained through power-frequency control, voltage control, and protection coordination. The MMS also manages economic dispatch of microgrid resources, including use of macro-grid power, which it will determine through an optimization process. The optimization takes into consideration variables including the cost of electricity, cost of gas or fuel inputs, weather, interconnected load forecasts, and microgrid DER characteristics and availability, among others. The MMS is typically designed to operate in an automated fashion under several different operating modes (i.e., normal grid-connected mode or islanded mode), but can be manually overridden if necessary.

DER Communication Network

Manufacturers of DER devices face the usual issues of communication standards and protocols for monitoring and controlling DER devices, particularly when they are interconnected with the electric utility system. In the past, DER manufacturers developed their own proprietary communication technology. However, as utilities, aggregators, and other energy service providers start to manage DER devices that are interconnected with the utility power system, they are finding that coping with these different communication technologies involves major technical difficulties, implementation costs, and maintenance costs. Therefore, utilities and DER manufacturers recognize the growing need to have a single international standard that defines the communication and control interfaces for all DER devices. Such standards, along with associated guidelines and uniform procedures, would simplify implementation, reduce installation and maintenance costs, and improve the reliability of power system operations.

Grid Separation Issues

Microgrids require a suitable mechanism to rapidly detect grid conditions that may necessitate transition to microgrid islanded operation and then initiate this transition quickly enough to avoid loss of critical loads. Similarly, the microgrid control facilities must allow a transition back to normal grid-connected operation without dropping the critical loads or risking potential damage to customer-owned and utility-owned DERs.

Fast switches enable quick intentional islanding and automatic re-synchronization of microgrid systems with the macro-grid. They are important components of the grid-connected electric microgrid system because they enable the system to detect conditions on both the utility and microgrid sides and to make rapid decisions about whether to stay connected to the macro-grid or to seamlessly separate and institute islanded operations. This approach contrasts with what is in place today for macro-grid-interconnected systems that can island, which require the on-site generation to trip, or shut down. With a fast switch, microgrids could electrically isolate themselves within milliseconds, preventing the need to trip connected generation. A similar process has to occur when the macro-grid comes back on-line and the microgrid reconnects—currently, generation is tripped for a time period before re-synchronization with the utility system can occur.

One of the goals of forming a microgrid is to maintain uninterrupted power to critical loads. The SEMI F47 document ("Specification for Semiconductor Processing Equipment Voltage Sag Immunity") specifies the minimum design requirements for voltage sag ride-through capability for equipment used in the semiconductor industry. The expected equipment performance capability is shown graphically in Figure 4-4, which shows voltage sag duration and percent deviation of equipment nominal voltage. As seen in this figure, the semiconductor equipment is expected to ride through a 20% voltage sag (80% of nominal voltage) for up to one second, and a 30% voltage sag (70% of nominal voltage) for up to 0.5 second.

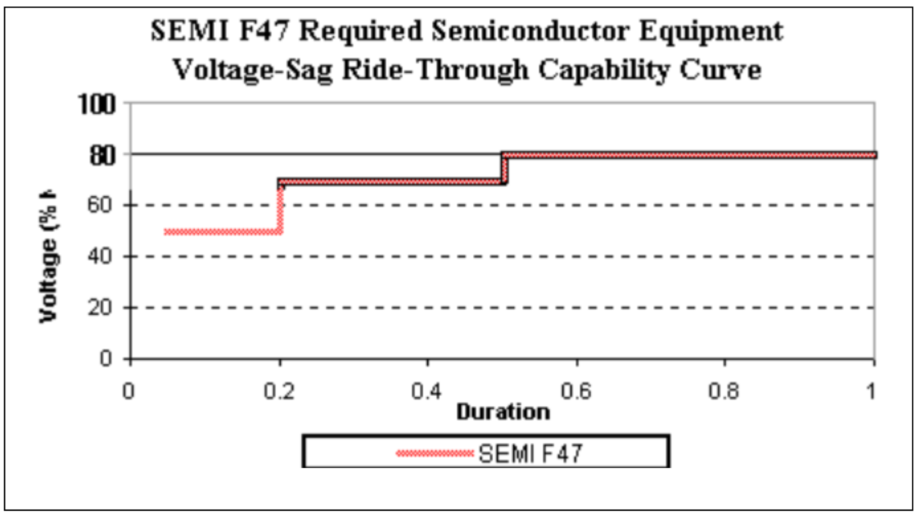


FIGURE 4-4 The SEMI F47 Voltage Sag Ride-Through Curve

If the loads of the microgrid are so sensitive to voltage dips that they require the system to meet SEMI F47 specifications, then existing protective equipment cannot act fast enough to separate from the fault under all conditions. Secure relay time to detect an under (or over)-voltage can be up to two cycles. Most medium-voltage breakers, after receiving a trip signal, require from three to five cycles to interrupt the circuit. Therefore, other system design considerations should be employed to prevent the voltage from going below 50% for three cycles or longer.

With such stringent requirements in place, the system must guard against “nuisance” separations due to temporary voltage sags caused by faults on the transmission network that do not result in permanent loss of power supply to the microgrid. One approach is to install dynamic “sag correctors,” which have recently become available. These devices target voltage sags, transients, and momentary loss of power. These devices are typically effective for only a couple of cycles. For longer protection periods, extending into the realm of many minutes, dynamic sag protectors that incorporate an energy storage device, such as a battery, are necessary.

Microgrid Protection Issues

A key design question for the microgrid is whether the microgrid should continue to operate following a fault on the microgrid or completely shut down. Per IEEE 1547, DERs are required to disconnect from the distribution circuit if the circuit becomes de-energized for any reason. However, if a nearby fault (within the microgrid) is cleared by the electric utility's protective devices or customer-owned equipment, the DERs ideally should remain in service. Note that most utilities consider this a double contingency (the first contingency resulted in transition to microgrid operation; the second contingency is a fault on the microgrid itself), and accept shutdown of the microgrid under such conditions.

If the utility desires that the DERs remain in service following a microgrid fault that is cleared by utility-owned or customer-owned equipment, coordinated fault protection must be provided for the portion of the electric distribution system that is operating as an island separate from the utility. Existing distribution system protection components (protective relays, reclosers, fuses, etc.), which are designed to provide well-coordinated fault detection and isolation under normal grid-connected circumstances, must also operate correctly when the distribution facilities they are designed to protect are operating as an island.

Most existing distribution protection systems utilize an overcurrent protection philosophy in which the protection devices operate when the current flow exceeds a threshold value. This threshold value (referred to as the "pickup" in protective relay vernacular) must be considerably higher than peak load current to prevent protective devices from operating under peak loading conditions. Under normal grid-connected circumstances, fault currents supplied by the central synchronous generators are many times peak load current, so it is possible to distinguish between peak load current and fault current.

Proper time coordination between protective devices is achieved via time delays. When a fault occurs while the distribution system is in grid-connect mode, the protective devices located furthest downstream from the normal source (the substation) operate faster than protective devices that are closer to the substation. The protection system time delays are based on fault current magnitude (i.e., the protective device will operate faster for larger fault current magnitudes).

When operating in islanded mode, high-magnitude fault currents (many times peak load current) may not exist, owing to the lack of synchronous generating sources. As stated in Chapter 3 of this report, the fault current supplied by inverters associated with solar PV units may be only 2 to 3 times normal load current, and this fault current decays rapidly. If a significant portion of the microgrid's generation has inverter interfaces, the change from utility-connected operation to islanded microgrid operation may aggravate a concern about using current-based fault detection.

The equipment used for detection of faults internal to the microgrid must work with, or around, the protection that exists for fault detection while connected to the utility. A means of detecting faults that is not dependent on a large ratio between fault current and maximum load current must be provided.

When operating such a system as an isolated microgrid, the available fault current from the microgrid resources for a fault on the utility distribution system will likely not exceed 5 times the full load current and may be considerably less. Given their extremely inverse time-current characteristics, fuses will be extremely slow in response to such faults and, most likely, impossible to coordinate with protection of the microgrid DER units. Faced with this situation, the protection engineer has two choices: (1) give up and accept the fact that a fault on the utility distribution system will result in a microgrid outage or (2) add protective devices to the utility distribution system that can be coordinated with the DER protection. If the existing protection is only fuses, choice (2) entails adding circuit breakers as well as protective relays, an expensive proposition.

5 USING STANDARDS TO INTEGRATE DISTRIBUTED ENERGY RESOURCES WITH DISTRIBUTION MANAGEMENT SYSTEMS

Technology advancements, as well as cost reductions, have been drivers for deployment of solar PV and battery storage by utilities, consumers, and third parties. These DERs are often connected to the grid at the distribution level, and distribution operational requirements are significantly impacted by their presence.

The presence of high penetrations of such units on the distribution system is having a profound effect on electric distribution designs and operating practices that have existed for a century or more. On feeders with very high penetrations of customer-owned generating resources, the potential exists for having more power supply than demand on a given feeder, resulting in reverse power flow that can cause unacceptable voltage profiles and possible overloads along the distribution feeder. In addition, some renewable DG units (solar PV and wind power) have highly variable power output, which can produce voltage fluctuations that reduce the overall quality of power supply on the feeder and, therefore, must be mitigated.

The power inverters that link solar PV and battery resources to the grid are highly capable devices with advanced message processing and fast power control and with nearly instant response to received commands and monitored conditions. Over the last few years, industry efforts have defined a wide range of standard grid-supportive functions that inverters may provide and standard communication protocols that allow these functions to be remotely managed.

Electronic inverter capabilities, if properly exposed and integrated with DMS, can transform high-penetration DERs from problematic uncertainties to beneficial tools for distribution management. To achieve these potential benefits, the DMS must account for the presence of DERs in its models and advanced applications. Furthermore, the DMS should take advantage of advanced DER control capabilities and opportunities for improving the reliability, efficiency, performance and overall quality of service for the electric distribution customers.

At this time, control of customer-owned DG units is limited to transfer-tripping larger generating units during a circuit outage (anti-island protection). However, DERs that are equipped with smart inverters and other intelligent controllers may be able to provide additional functionality, such as Volt-VAR support, to meet the changing feeder requirements on demand. For the purposes of this report, any control function that alters the normal operation of the DER (normal operation entails, for example, achieving maximum power output from the generator at all times) is referred to as “Advanced DER Management.”

In the meantime, the current generation of DMS does not consider support from DER integration. In most cases, DER support within the DMS is limited to monitoring the output of “utility scale” (> 1-MW) DERs. In addition, existing industry standards define advanced functions for DERs only at the individual device level, and lack the more aggregated, feeder-level representations that are needed for enterprise integration.

Further development of DER connection standards (e.g., IEEE 1547) is needed to ensure that such control strategies can be executed without producing unacceptable electrical conditions out on the feeder. Suitable tariffs must also be developed for compensating owners of DG resources for ancillary services (e.g., VAR support) that they provide. When these technical and commercial issues are resolved, it will be possible to use DERs to optimize the performance of the distribution system under normal and abnormal (emergency) operating conditions. The DMS is expected to interact with a DERMS to be able to use the DERs in the most effective manner. Figure 5-1 depicts the overall DMS-DERMS architecture.

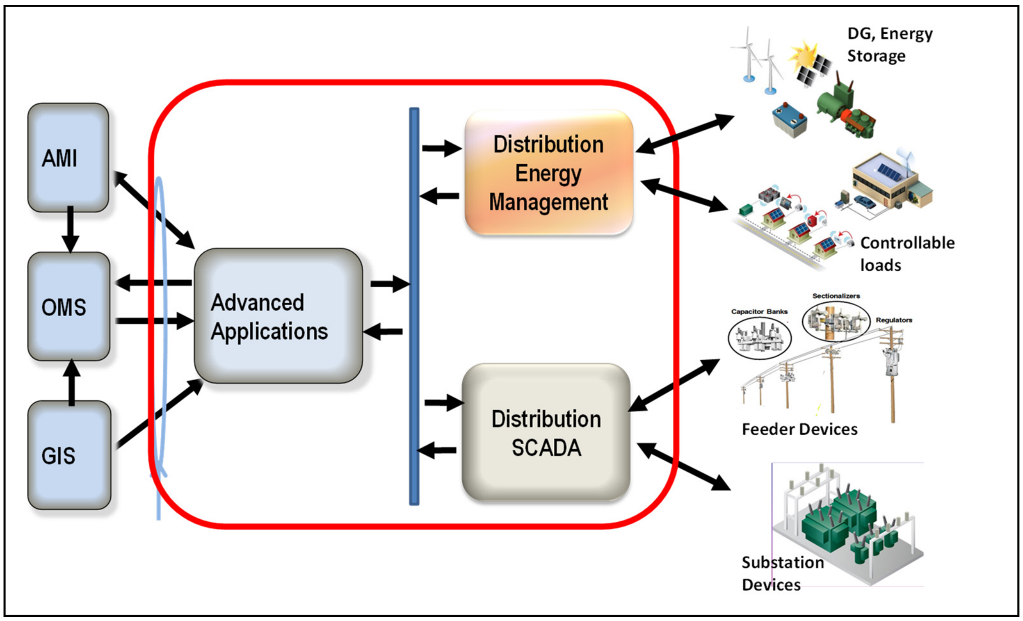


FIGURE 5-1 Example DMS-DERMS Architecture

5.1 MANAGING DISTRIBUTED ENERGY RESOURCES

Over the past few years, the utility industry has made significant progress in defining common grid-supportive functions for DERs such as solar PV and battery storage, and defining the open-standard communication protocols needed to connect these devices into utility networks. Figure 5-2 illustrates a utility enterprise, including a central office application environment (in blue) and field networks and equipment (in green).

Industry activities to create DER standards have thus far focused almost exclusively on the behaviors of individual DER units and the communication protocols over the field networks that connect directly to these devices (reference point 1 in Figure 5-2). The functional aspects of these standards are described in a publicly available report by EPRI entitled "Common Functions for Smart Inverters,"[3] and in IEC TR-61850-90-7.

[3] "Common Functions for Smart Inverters, Version 3," Electric Power Research Institute, Palo Alto, CA, 2013, 3002002233.

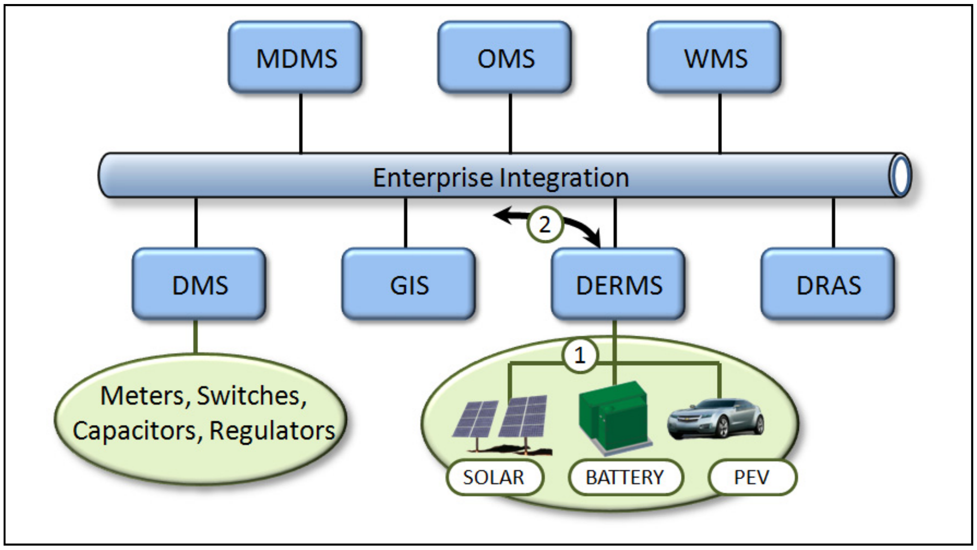


FIGURE 5-2 Utility Enterprise Diagram

The functions include, for example:

- Intelligent Volt-VAR control
- Intelligent Volt-Watt control
- Reactive power/power factor
- Low-voltage ride-through
- Load and generation following
- Storage systems charge/discharge management
- Connect/disconnect
- Dynamic reactive current injection (responding to changes in voltage, dV/dt)
- Max generation limiting
- Intelligent frequency-watt control
- Peak-limiting function for remote points of reference

These standardized functions have been mapped into various communication protocols, supporting the same set of functions in different environments, including the following:

- Support in the IEC 61850-90-7 (mapping to DNP3)
- Support in field SCADA systems using the DNP3 protocol[4]
- Support in residential home area networks using SEP2.0[5]

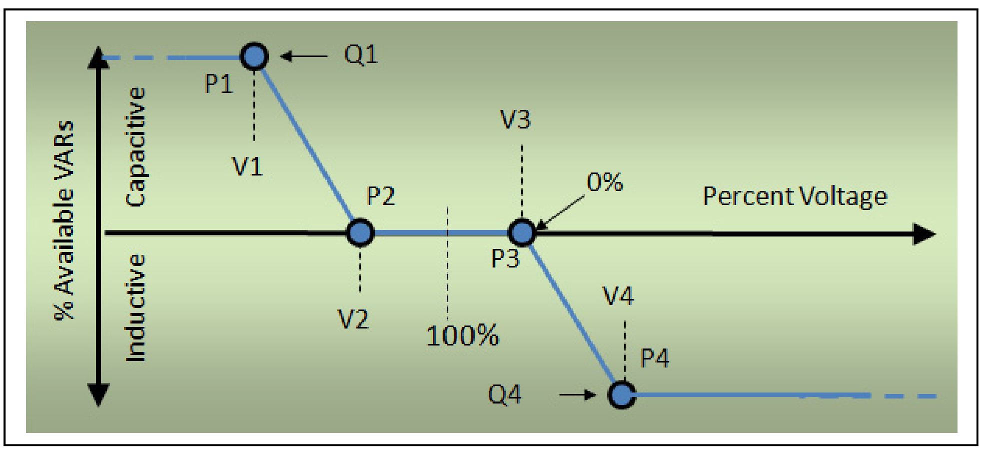
Although these standards focus on the field connection to the individual DER, they were developed with a view toward the present activity—making it possible for many DERs, including different types, sizes, and brands, to be managed uniformly and collectively.

4 DNP3.org, Application Note AN2011-001.
5 ZigBee Alliance, Smart Energy Profile Version 2.0.

In Figure 5-2, the function of managing the DER devices is shown as a DERMS enterprise application. In actual implementations, DERMS functionality may or may not be in the form of dedicated software. Standalone DERMS products could be developed and deployed, or DERMS functionality could be integrated into DMS, EMS, SCADA, or other applications. Nevertheless, it is beneficial at this early stage of industry consideration to think of a DERMS as a separate logical entity so that the interactions between DERs and other utility systems can be identified and supporting information standards developed.

5.2 NEED FOR STANDARD DERMS ENTERPRISE FUNCTIONS

Before information and communication standards can be developed to support DERMS integration with DMS and other enterprise applications, the functions that a DERMS presents to the utility enterprise must be identified and could also be standardized (reference point 2 in Figure 5-2). To explain what is meant by a "function that a DERMS presents," consider the case of the reactive power generation capabilities of inverters, and the challenge of exposing these capabilities to a DMS in a useful and manageable way. Per the existing industry standards identified previously, each inverter might be configurable to follow Volt-VAR curves. As illustrated in Figure 5-3, these curves are user-defined in the form of an array of points that define a piecewise linear shape.



Source: "Smart Inverter Function Modeling in OpenDSS, Rev. 2," EPRI Technical Update, October 2013

FIGURE 5-3 Volt-VAR Curve Configuration via Array of Points

The curve identifies the level and sign of VAR output as a function of the AC voltage observed at the inverter's point of electrical connection. When many DER devices with this capability are connected on a single distribution circuit, the curve settings could be different for each device for a variety of reasons, such as the following:

- It may be more effective to have VAR generation at points where the circuit impedance is higher, such as points further from the substation.

- Because of present watt levels, some DERs may have more or less present capacity for VAR generation.

- Agreements with DER owners may affect VAR availability, maximum VAR levels, or cumulative VAR utilization.

- Limitations of local assets such as transformers or protection equipment may limit VAR availability.

- Local voltage variability (e.g., variable-load-induced) may result in different dead-band or hysteresis settings in the Volt-VAR configuration.

If the Volt-VAR settings vary from one DER to another, and a large number of devices are connected to a distribution circuit, then managing overall VAR behavior of all DERs becomes very complex. If the DERMS application shown in Figure 5-2 performed no function, then the complexities of managing the many DERs would be directly exposed to other applications within the utility enterprise. This situation is undesirable, and does not result in DER services at the enterprise level that are useful tools to support DMS functions such as those described previously.

5.3 IDENTIFYING EXAMPLE ENTERPRISE FUNCTIONS

The conceptual purpose of a DERMS is to manage many diverse DERs, to understand the unique status and capabilities of each, and to present these capabilities to the DMS and other applications in a more useful and manageable way. This could mean aggregating the capabilities of individual devices, and transforming their settings and effects so that they become attributes at the circuit, feeder, or segment level. Below are examples of DER-related services that a DERMS could provide.

- **Identify Installed DER Capability:** A function to identify the total capability of installed DERs. This could include watt ratings, VAR capabilities, energy storage capability, etc. These capabilities could be provided at the level of a complete distribution circuit, a single feeder, or a line segment.

- **Report Present DER Status:** A function to report the present activity/state of DER devices. This could report real-time watt generation, VAR generation, battery state of charge and rate of charge/discharge, on-/off-line status, etc. As possible, these would be aggregated and reported as an attribute of the circuit, feeder, line segment, or phase.

- **Provide Forecast/Prediction of DER Opportunity:** A function, based on weather, status, historical, and other information, by which a DERMS may provide a forecast (minutes, hours, days) of DER output, range of adjustability, VAR availability, etc.

- **Connect / Disconnect DER:** A control function by which all DERs on a specified part of the distribution system may be disconnected from or reconnected to the grid.

- **Provide VR Support:** A control function by which varying degrees of VAR support may be requested on a circuit, feeder, or line-segment basis.

- **Provide Phase Balancing:** A function by which total load may be balanced across the A-B-C phases at a given point of reference.

- **Coordinate DER with Circuit Reconfigurations:** A function by which all DERs in an affected circuit section may be informed of a change in the circuit configuration. For example, if a section is switched to an alternative substation, the characteristics of the DERs may be modified to work in harmony with the new circuit configuration.

- **Provide Maximum Capacitive VAR Support:** A function by which a DERMS provides maximum capacitive VAR support for conditions such as transmission-system VAR contingencies. The maximum capacitive VAR level that all DERs on a feeder are able to provide may be dependent on many factors, including the voltage at each device, present watt levels, etc.

- **Provide Support for Conservation Voltage Reduction Mode:** A function by which a DERMS manages the DERs on a feeder to optimally support a Voltage Reduction Mode when it is active.

In order to provide services like these, a DERMS could utilize many existing standard smart-inverter functions. Table 5-1 indicates some examples of how standard smart-inverter functions (horizontal axis) might be utilized by a DERMS to produce more aggregated, feeder, or segment-level services (vertical axis) that would be useful to a DMS or other enterprise applications.

The actual method that a provider of DERMS functionality might employ to produce a given high-level service would likely be up to the DERMS provider. Industry standards are appropriate and beneficial for the upstream (enterprise) and downstream (DER) interfaces, but the internal behavior of a DERMS is a place for innovation, competition and product differentiation.

Coordinating a DERMS with DMS

If a set of useful DER-related services were made available as suggested herein, and exposed using standardized interfaces and protocols, then it would be increasingly practical for a DMS to have capabilities to make use of these services. And not just a DMS and/or a DERMS, but many enterprise applications may be involved. DER-related services may be provided by GIS, weather system, markets, metering, and other applications. Likewise, DER-related services may be consumed by billing systems, forecasting systems, work management systems, and others.

The specific ways in which a DMS might utilize DER capabilities to support distribution management are best determined by DMS providers and utilities. It is their domain of expertise, and need not be standardized as long as there are supporting standards for the functions and information at the interfaces between applications.

TABLE 5-1 Example Utilization of Standard Inverter Functions to Provide Enterprise Services

	Standard Functions for Individual Smart Inverters														
DERMS Enterprise Services (Circuit, Feeder, or Segment Level Functions)	Status Monitoring	Event Logging	Nameplate Values	Volt-VAR Curves	Volt-Watt Curves	Reactive Power / PF	Low Voltage Ride Through	Load & Gen Following	Chg/ Disch of Storage	Connect/ Disconnect	Dynamic Reactive Current	Max Generation Limiting	Frequency-Watt Curves	Peak Limiting Function	Circuit Config and Islanding
Identify DER Resources by Circuit/Segment			X												
Retrieve DER Capabilities by Circuit/Segment			X												
Retrieve DER Abnormal Condition Characteristics	X	X													
Retrieve Forecasted DER Capabilities	X	X							X						
Retrieve Present DER Status	X														
Connect/Disconnect DER										X					
Stay Off After Trip															
Limit DER Maximum Generation												X			
Peak Limiting														X	
Provide Requested Var Support				X		X									
Request Future Watt Support									X						
Provide Requested Watt Support					X				X			X	X		
Provide Requested Power Factor						X									
Provide Maximum Capacitive VAR Support				X											
Provide Voltage Regulation Support				X	X						X				
Inform DER of Alternate Circuit Configuration															X
Phase Balancing												X			

Given the broad range of functions that a DMS may perform, and the broad set of DER-related services that could be provided, there are numerous ways that a DMS might leverage DER-related services. Table 5-2 continues the example started in the previous section, providing mappings of DER services onto DMS utilization. In the following section, some more detailed examples are provided.

Enterprise Integration Standards

Interoperability of systems requires open standards, which include both functional behaviors (i.e., standardizing the DER-related use cases and services on the enterprise) and the communication standards (information models) needed to support these functions.

TABLE 5-2 Example Utilization of DERMS Enterprise Services to Support DMS

	Example DERMS Enterprise Services																
Example DMS Functions	Identify DER Resources	Retrieve DER Capabilities	Retrieve DER Abnormal Conditions	Retrieve Forecasted DER Capabilities	Retrieve Present DER Status	Connect/Disconnect DER	If Trip Stay Off	Limit DER Maximum Generation	Peak Limiting	Provide Requested Var Support	Request Future Watt Support	Provide Requested Watt Support	Provide Requested Power Factor	Provide Maximum Var Support	Provide Voltage Regulation Support	Inform DER of Alt Ckt Config	Phase Balancing
Maintain Voltage Profile	X	X						X							X		
Voltage Reduction	X	X													X		
Volt-Var Optimization	X	X			X					X		X	X				
Power factor correction	X	X								X			X				
Fault Location Isolation and Restoration	X	X			X					X		X			X	X	
Load balancing (optimal network	X	X			X					X		X				X	
Phase Balancing	X	X															X
Maintain V & F of Microgrids	X	X								X		X	X		X	X	X
Contingency Analysis	X	X		X	X												
Predictive Fault Location	X	X															
DER Dispatch								X									
Emergency Load shedding												X					
Switching Order Management				X		X	X										
Short Term Load Forecasting				X													
Hot Line Tagging							X										
Management of EV Smart Charging				X							X	X					
Management of V2G Capabilities				X							X	X					
Demand response/ peak shaving									X								

Communication standards in the enterprise integration environment include IEC 61968/61970 CIM and MultiSpeak and are different from standards that cover field network protocols (e.g., IEC 681850, DNP3), in terms of both design and purpose.

6 CONCLUSIONS AND RECOMMENDATIONS

DERs of various types are becoming increasingly common in utility distribution systems. Technology improvements continue to add new capabilities and drive down costs, raising the likelihood that higher penetrations of these devices will occur. Fortunately, the present levels are low in most circuits, and the utility industry has the time and opportunity to develop a framework of standards for multi-vendor interoperability to guide the arrival of these devices and their integration. A proactive approach is much preferred, rather than waiting until penetration levels are high and reacting to the cost and maintenance associated with the complexity of incompatible devices and applications.

There is a need for standards (or guidelines or recommended practices) to support the enterprise integration of DER technologies and the implementation of DMS to obtain the maximum benefit in terms of efficient and reliable grid operations.

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