Active Network Management

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1. INTRODUCTION

The vision of smart grid is still shaping up and a lot of research and development work has to be done to reach this goal. A shared vision of smart grid is a very important issue in order to develop commercially successful and useful products for smart grids. This vision should be shared by network companies, product vendors and network customers. At the moment many proposals and some real examples are presented from different perspectives: Some proposals are concentrating on integration of large-scale wind power on power system, some other may consider utilization of advanced energy meters and advanced metering infrastructure (AMI) in distribution network management, and so on. The concepts of smart grid are e.g. Active network, IntelliGrid, Power cells, Virtual power plant and Microgrid.

1.1. DRIVERS OF ACTIVE NETWORK

The energy markets are in transition and there are many drivers for creating a new kind of power delivery system for the future. There are many drives and needs, as follows:

- The penetration of distributed generation (DG), especially based on Renewable Energy Sources (RES), will continue due to environmental reasons.
- The European and North American vision is to have common electricity market areas with a high penetration of distributed power generation.
- Efficient use of energy at customer level and intelligent demand response has become an essential issue.
- Power quality (supply reliability and voltage quality) requirements will increase due to public and regulatory actions and at the same time failure rates are expected to increase due to the climate change.
- There is a need, due to economical reasons, to increase the utilization rate of existing networks. The traditional way of developing a distribution network would be to invest in passive wires which would lead to a decrement of the utilization rate.
- Many components of existing networks are reaching the end of their life cycles. They need replacement or continuation of their lifetime in a safe and controlled way.
- Regulation of network companies will tighten up while companies want to ensure the profitability of their business. This will mean rationalization of network management both in short- and long-term perspectives.
- The risk of major disturbances is increasing, both the probability and the consequences. The reason for this increased probability is the complexity of the power network and the increased failure rate due to climate change. The consequences are increasing due to society's higher dependency on power supply.

Electricity distribution networks create a market place for small-scale power producers (i.e. distributed generation) and for customers (i.e. users of electricity). Here, the role of distribution networks is of great significance. For example in Finland, about a half of the total price of electricity for small customers and over 90% of all interruptions come from the distribution process.

Considerable amount of RES in Europe represents distributed generation (DG). The increment of DG based on renewable energy sources is the main driver for the development of active distribution network at the moment. DG provides also a good potential as a controllable resource for the active network. Other existing controllable resources are direct load control, reactive power compensation and demand side management. From network management point of view the increasing amount of DG is often seen as negative development, which brings the complexity of transmission network to distribution network level. The main reason for the complexity is caused by the present methods for managing the distribution networks as well as the features of different active resource components themselves, which are not sufficiently developed to enable easy interconnection.

So far loads and customers have been passive from network point of view. By making the customer connection point more flexible and interactive, the demand response functions (e.g. by real-time pricing, elastic load control) are more achievable and the efficient use of the existing network and energy resources by market mechanisms can be improved. The traditional passive network management or “fit & forget” principle in DG connection needs to be changed into active network management (ANM). The integration of DG and other active resources into a distribution system is a requirement in order to fully exploit the benefits of active resources in network management. With proper management of active resources the overall system performance may be improved from presently used practices.

There are also some additional drivers which are affecting on distribution networks even without the presence of DG penetration. The regulation of network monopolies is realised in many cases by the regulation of network profit which may also be affected by power quality (e.g. interruptions). That kind of regulation encourages companies for efficient utilisation of network assets without sacrificing the reliability of power supply. The aim of active network in general is to increase the utilization rate of existing network. The traditional way of developing a distribution network would be the investment on passive wires which would lead to decrement of utilization rate.

Also customers´ expectations for extreme reliability and quality of power are increasing simultaneously with an aging network infrastructure. Therefore significant investments will be needed in the coming decades. It is time to reconsider traditional network solutions in order to secure the efficiency, security and reliability of networks in the long run.

1.2. ACTIVE NETWORK IN GENERAL

The concept of active distribution network may be characterized by words like flexible, intelligent, integration and co-operation. The active network is flexible because it utilizes controllable resources throughout the network. Respectively the passive network has flexibility by network capacity i.e. network itself may handle all probable loading conditions. Intelligence is simply investments on controllability and information and telecommunication technologies instead of passive lines, cables, transformers and switchgears. Active networks also require that DG unit are integrated into network instead of connecting them by the “fit & forget” principle. The integration of DG units includes both the system requirements and the ancillary services in order to bring active resources available for ANM. The co-operation of individual controllable resources will generate synergy benefits for the active network by higher level decision aid or management system.

Investments on network reinforcement for DG connection may be cheaper to realize with secondary devices like relays, controllers and information technology than with primary equipments like wires and transformers. DG-GRID project investigated on very general level how much savings may be achieved by active networks in typical UK and Finnish distribution systems [Cao 06]. The cost of DG connection is obtained by calculating the cost of network reinforcement needed to mitigate the technical problems (voltage rise and fault current level) and the benefit of DG is determined by computing the reduction in distribution losses and the ability of DG to release network capacity which can be used to accommodate future loads. The benefit of active management for reducing network reinforcement costs is clear for UK networks and Finnish rural networks.

Active networks might help to reduce investment costs of DG connection in some cases, but they may increase network operational costs (e.g. losses) on the other hand. The lifetime of applied technical solutions in active networks may also be shorter and the network design and planning is currently more time consuming than traditional reinforcement scheme. Active networks are still in infancy and practical experiences too narrow in order to have complete guidelines for network planning. However a remarkable number of demonstrations and research projects have been identified to consider ANM [Mac 08]. The balance between operational and capital expenditures in network business is also very much dependent on network regulation practices and therefore general conclusion about potentiality of active networks is not given here. [ANM 08]

1.2.1. Definition of active network

Active network concept has different aspects as shown in Figure. 1.1. It includes novel solutions of infrastructure for future power distribution, e.g. use of power electronics and DC (i.e. direct current). Active resources (i.e. DG, loads, storages and electricity vehicles) actually change the traditional passive distribution network to be an active one. New network solutions and active resources call for novel ICT solutions for network operation and asset management providing intelligence to active networks. Active network enables active market participation of customers and also has effect on changes in the business environment. Active network is customer-driven marketplaces for DG and consumers.

Active networks can be characterized as follows:

- interactive with consumers and markets
- adaptive and scalable to changing situations
- optimized to make the best use of resources and equipment
- proactive rather than reactive, to prevent emergencies
- self-healing grids with high level of automation
- integrated, merging monitoring, control, protection, maintenance, advanced IT systems, etc.
- having plug-and-play features for network equipment and ICT solutions
- secure and reliable

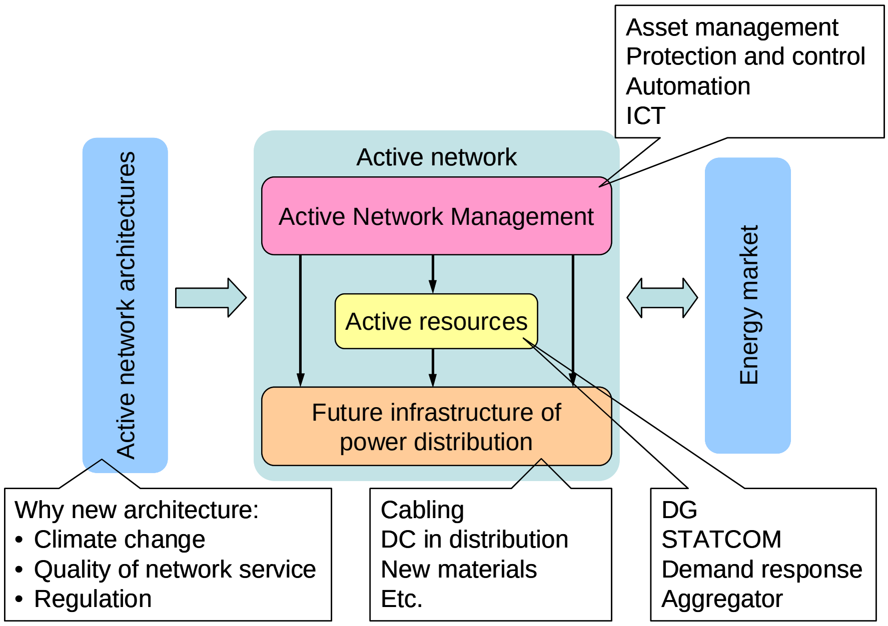


Figure 1.1. Aspects of active network.

A traditional grid includes centralized power generation, and at distribution level one-directional power flow and weak market integration. Active networks include centralized and distributed power generation produced substantially by RES. They integrate distributed and active resources (i.e. generation, loads, storages and electricity vehicles) into energy markets and power systems. Active network can be characterized by a controllable multi-directional power flow.

Smart metering has been seen as an essential part of distribution network vision. A remotely readable energy meter is being developed to be a piece of intelligent equipment (i.e. an interactive customer gateway) including, in addition to traditional energy metering, different kinds of new advanced functions that are based on local intelligence. This gateway opens possibilities for network companies, energy traders and service providers to offer new kinds of added-value services to end customers.

The aim of ANM is to add more flexibility for network management in order to utilize existing network assets more efficiently. The addition of flexibility comes from the utilization of active resources through grid code requirements or ancillary services. Active resources are needed for integration as a part of the distribution system instead of just connection to it. Active resources are typically utilized in extreme network conditions e.g. when the network is not capable of transferring produced wind power.

The distribution network management concept can be based on existing systems like SCADA, Distribution Management System (DMS), substation and distribution automation and Advanced Metering Infrastructure (AMI). The ANM system operates on protection, decentralized control and area control levels. The intelligence of ANM is based on investments in controllability and ICT. Area control level may e.g. be used to coordinate individual resources and thereby increase the synergistic benefits of network management.

To implement the ANM concept a collection of partial ANM solutions are needed. These bring new features for protection system and automatic control system levels. New protection system features are e.g. distance and differential protection schemes and communication based Loss-of-Mains protection. At the decentralized control system level the ANM concept includes local voltage, power quality and frequency control, load shedding and production curtailment. Many new features are also added for the area control level: coordinated voltage control, power flow management, fault location schemes, automatic network restoration and island operation.

1.2.2. Functions of active network

Active network is such a broad concept that it may include anything related to distribution network. Next some active network functions related to distribution network operation are shortly described.

Active network is able to detect and measure bi-directional current flow through every node connected to MV grid, MV/LV transformer substations and LV grid nodes and elements. In this way it possible to avoid overloads, extends grid asset life span and improves operator ability to quickly identify troubles and intervene to fix them. Similarly the system should be able to monitor in real-time all relevant network quantities like voltage, power quality, outages, etc. One information source among others is AMI.

The system must be able to automatically determine the best grid network configuration based on pre-defined performance targets (e.g. locate distribution network overloaded nodes – under-utilized, vulnerable to weather conditions) and restore optimal status without operator intervention. The system must be capable of continuously updating performance limits of all relevant grid network components - this in turn allows to keep the whole grid system optimally balanced in changing conditions (e.g. weather - meteorological induced changes). When events causing grid network congestion occur, the system must be able shed load, activate demand response actions, curtail power production or utilize energy storage devices in order to restore an optimal (at least acceptable) new state of equilibrium. In addition, the voltage regulation is becoming increasingly important as the amount of DG in distribution network is predicted to increase significantly. Therefore the system must be able to dynamically adjust and fix the voltage in real time.

Automatic fault location, isolation and supply restoration would provide self-healing capabilities for radial distribution networks. Network reliability, which is the most important topics of active networks, may also be improved by replacing overhead lines with cables, removing overhead lines from forest to beside a road, providing parallel (backup) connections to important nodes and reducing outage area with new substations, feeders and reclosers. Island operation provides an alternative method to ensure supply reliability when DG units suitable for island operation are available.

Besides a remote meter reading and billing smart energy meters may provide many additional benefits for a DNO. Smart meter may be utilized to detect energy theft. It may provide remote meter connection/reconnection when contract is activated/de-activated. The meter can isolate customers automatically in case of dangerous faults and events, such as broken neutral conductor, wrong phase order, under and over voltages, etc. Once conditions are back to normal operation can be restored remotely or the meter can restore it by itself. Remote disconnection may be utilized e.g. to protect network maintenance workers in case of reverse power from DG units. Measurement information may be utilized in real-time as spontaneous alarms if operational limits are exceeded or in network planning to get information about e.g. network component loadings. Typically load shedding is also possible.

Active network may also utilize active demand service which deals with user energy load management. A host of new functionalities and interaction mechanism are being introduced, ranging from "price signals" enticing users to adjust load to receive rebates, to grid commands able to interact with intelligent energy devices and disconnect non-critical loads in order to shave energy peaks upon demand. Locally measured frequency is a measure of power balance in electricity system. This information may also be used for direct or indirect (e.g. thermostat setting value) control of load demand in order to provide frequency control and disturbance reserves for transmission system operator. Aggregation of real-time information from multiple small-scale reserves (e.g. heating and cooling devices) is also needed in order to monitor the capacity and the response of reserves. Similarly the controllability of other active resources like DG, electrical vehicles and energy storage may be utilized in network management.

2. IMPACTS OF DISTRIBUTED GENERATION ON ELECTRICITY SYSTEM

DG has different impacts on electricity system dependent on generation type and time scale considered in assessment studies. The Figure 2.1 represents impacts in two-dimensional space where time scale and impact area are the coordinates. DG has local impact (power quality, voltage management and distribution efficiency) in distribution network. However the amount of DG connected might become large enough to have regional (grid stability, transmission efficiency, congestion management and adequacy of grid) and also system wide impacts (reserves, hydro/thermal efficiency, emissions and adequacy of energy/power). This kind of scenarios has already happened in Germany, Denmark, Spain, Italy, Portugal and Irland due to wind power, solar power and combined heat and power units.

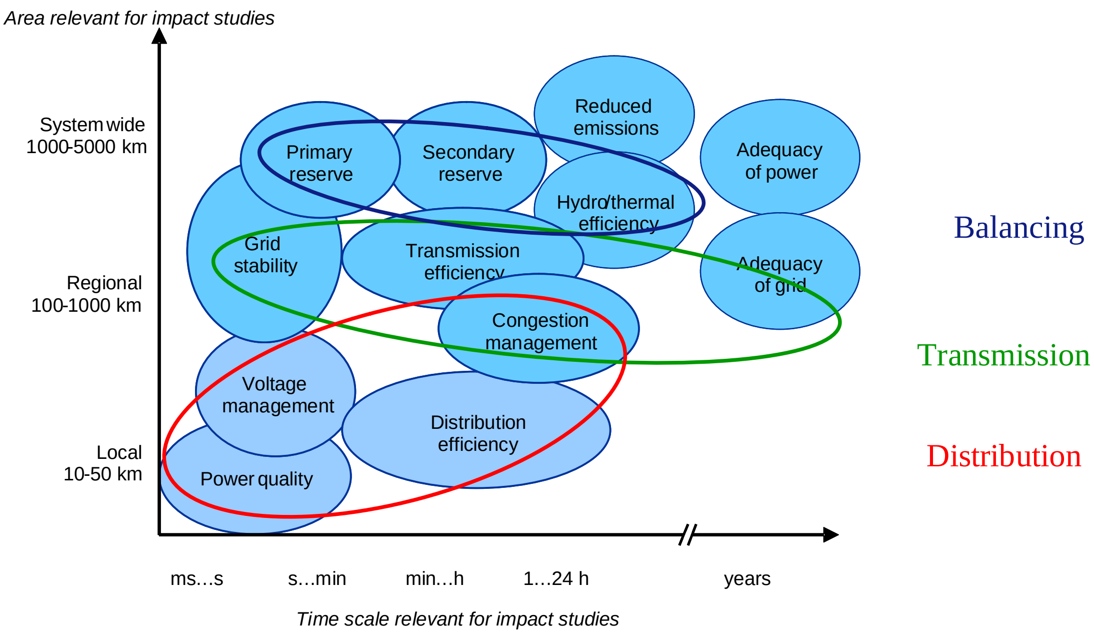


Figure 2.1. Impacts of DG on electricity system.

The electricity system regulation is realized by load following principle. Control reserves are needed to consider load and production forecasting errors which always exists. When the amount of intermittent power production increases that probably increases also production forecasting errors which will impact on control reserves. However the smoothing effect of e.g. wind power is stronger when large control area is considered over long time horizon. This means that local wind farm power variations are not directly influencing on electricity system regulation. DG might have impact on disturbance reserves if a fault in transmission network affects on huge number of DG units and they disconnect at the same time. Fault ride through requirements are a typical method to avoid this unfavourable event. Another scenario might be a storm which might cause a shutdown of major part of wind power in few hours from nominal to zero power.

Intermittent power production has also impact on other conventional production units. Here the interest is on how the conventional capacity is run and how the variations and prediction errors of wind power change the unit commitment: both the time of operation and the way the units are operated (ramp rates, partial operation, starts/stops). On the longer time scale the adequacy of power generation is also interesting question. Wind power's aggregate capacity credit during peak load situations, high energy capacity energy storages and generation companies' willingness to maintain rarely used reserve units affect on adequacy of power generation.

2.1. TRANSMISSION ISSUES

Congestion management in transmission network is handled by e.g. price areas. Congestion occurs when the transmission network is unable to transmit enough power to the desired consumption (shortfall area) or to transmit generated power to other areas (surplus area). In both cases there exists a bottleneck between areas. Price areas are used at Nordpool spot market to manage congested transmission network to balance generation, consumption and export/import capacity at each area. The amount of intermittent wind power in Denmark might exceed time to time the consumption of its local area plus export capacity of transmission network. During those hours the area price might be negative due to need to reduce surplus generation. Similarly price spikes at the spot market becomes more frequent due to shortfall of generation capacity e.g. during a calm periods and start-up of expensive reserve units. Transmission network congestion might also occur inside a price area which is managed by counter-trade at Nordpool spot market.

Regional adequacy of transmission network is dependent on the location of DG units relative to the load and the correlation between produced power and load consumption. Typically wind power units are not located close to load centres due to available wind resources and visual impacts of turbines. Also the correlation between wind power and load consumption is weak. Instead combined heat and power units are located in load centres and the output power correlates well with load consumption at least in Nordic countries. The produced power of DG units may relieve transmission capacity of regional network when correlation of power production and load consumption is strong and postpone otherwise needed network investments. In opposite case the power flow direction may change and dependent on production capacity of DG there might be needed to increase network capacity. There are also a variety of means to maximise the use of existing transmission lines like use of online information (temperature, loads), FACTS and wind power plant output control.

2.1.1. Grid requirements

The penetration of DG is forcing system operators to re-consider the contribution of DG units to system services as voltage control, reactive power support, fault-ride-through (FRT) capability, frequency control, reserves, etc. [Jan 07] When the penetration level of intermittent power production increases additional disturbance (secondary) reserves and/or contribution of uncontrolled production units to participate on frequency control are needed. The frequency (primary) reserve is not affected when the fluctuation of DG units is smaller than load fluctuation. The location of reserves may also change when a DG replaces centralized power production providing reserves. [Ple 03, UCTE 07] For example combined heat and power (CHP) units are mainly following the heat demand or market price and their production correlates well with electricity demand in Nordic countries. Wind power does not have such correlation which certainly will increase the need for control reserves and when the control reserves are remotely located, wind power will also increase the demands on power transmission.

Synchronous machines and modern wind turbines have possibilities for both tolerance and management of voltage and frequency variations. These equipments may actively participate in grid operation. Active power of wind turbine can be controlled by maintaining power output less than available output. Turbine ramp rate control and governor droop characteristics may also be programmed into the power electronic controller. The reactive power output of modern wind turbine may be utilized to control connection point voltage or power factor if the capacity of power electronic converters allow that. Altogether the modern wind turbine may be operated like or even better than a conventional power plant. [Gee 08, Ene 08]

Some countries are already requiring FRT and voltage support capabilities for new wind turbines connected to high voltage (HV) grid [Hol 07]. Active power regulation of a wind turbine connected to transmission level is required in Denmark [Sør 06]. The frequency and voltage ranges and tripping times are also required to fulfil by connection requirements. Other solutions for improving stability of already existing wind power plants are SVC (Static VAr compensator) or STATCOM (Static synchronous compensator) at wind power plants.

2.1.2. Fault-ride-through capability

When the share of DG increases the dynamic consequences of immediate tripping of DG units may become adverse when short-circuit in transmission grid is seen by several DG units. Even during a fault at distribution network, there may occur unnecessary disconnection of DG units due to unwanted trips of feeder or DG unit protection relays, loss of synchronism of synchronous generators, sustained over-speed and over-current of asynchronous generators or over-current and DC over-voltage of power electronic converters.

First of all the sensitive disconnection of DG units due to a fault at the feeder or line supplying the DG unit is a safety issue which must always have the top priority at network development. However the consequences of stability issues for the whole power system and also for DG owners and other distribution network customers are becoming more important when the disconnection of DG units may cause system wide stability or local power quality problems.

The current operational practice of distribution network requires disconnection of DG units when a fault occurs. This will keep the operational conditions simple and clear, safe and suitable for auto-reclosing. The purpose of DG unit connection point protection (e.g. frequency and voltage relays) is to eliminate the feeding of fault arc from a DG unit and to prevent unintended island operation. The settings of these relays must be quite tight in order to detect unintended islands fast enough.

From the system point of view the unintended island protection of DG units creates a remarkable risk for power system instability in frequency problems like UCTE disturbance in 4.11.2006 [UCTE 07] or in transmission system faults when a deep voltage dip is met by several DG units. A fault at transmission network may affect on large area even considered at medium voltage (MV) level. Similarly during the UCTE disturbance, a significant amount of DG units (total over 10 GW) tripped due to the frequency drop in the West area of UCTE system.

The FRT capability is a capability of production unit to withstand deep voltage dips due to faults in the network and to support network voltage by supplying reactive power to network during a fault. When a DG unit has FRT capability, the settings of DG unit under voltage relays must be loosen which makes it less sensitive. DG unit should stay connected during a specified fault clearing time and voltage dip requirement.

This creates a safety risk because unintended island operation may not be detected fast enough from local measurement only. This requires development of the relay protection schemes of distribution network. This situation is seen as an interaction of FRT capability of DG unit and distribution network relay protection (feeder protection and DG unit connection point protection). When advantaged protection schemes are applied in distribution network protection there is not immediate need to disconnect DG unit in every fault situation. DG units should also withstand much greater variations in voltage and frequency without tripping of DG unit in order to support power system. This will benefit the balancing and stability of power system and will make possible to utilize island operation at distribution network level to improve the reliability and security of power supply.

2.2. DISTRIBUTION ISSUES

The presence of DG can have many positive impacts on the distribution network usage which are listed in table 3.1. The realization of these positive impacts, which are often called "system support benefits", is, however, is not self-evident but depends on the reliability, location, size and controllability of DG resources. [Bar 00] Voltage support, for instance, is largely dependent on the type of the DG unit but also on the way that the DG units are required to be operated. The voltage control capabilities of directly coupled wind turbines using induction generators are very poor, whereas, converter connected DG units have relatively good abilities for supporting network voltages provided that the dimensioning of the converter allows this. [Ack 05] The larger the DG production in a feeder, the more important is the coordination of the DG operation and feeder operation strategies. [Bar 00] In the EU, there is, however, no obligation for the DG unit owners to collaborate with the network utility. DG can sometimes also increase the reliability of the supply by enabling the supply restoration on a larger area than what would be possible without DG. This, however, is questionable in case of DG units that have low availability on demand (see table 2.2).

Table 3.1.Positive impacts of distributed generation on distribution networks [Bar 00]

Positive impacts of DG on distribution network
Voltage support and improved power quality
Loss reduction
Improved system reliability
Transmission capacity release
Postponed network infrastructure upgrades

The presence of DG, however, also raises many new challenges. The most serious of these are probably related to network protection and voltage levels. In the traditional electric power system design the flow of electric power has been unidirectional, namely from the transmission grid towards lower voltage levels as explained earlier. Unidirectional power flow has enabled relatively simple network design especially from protection perspective. The presence of distributed generation is, however, now changing this simple basis. [Jen 00, Mäk 07a] This chapter presents the most important new challenges that DG has brought up.

2.3. Protection impacts of DG

The impacts of DG relate also to the sensitivity and selectivity of typical network protection. Requirements for the protection of distribution networks are changing considerably. Protection schemes designed for unidirectional power flow may become ineffective. Due to the presence of DG, some faults may be detected with significant delays or, in the worst case, not detected at all. On the other hand, unnecessary relay operations are possible on feeder relays or at the DG connection point. The difficulty of detecting unintended island situations makes the situation even more complex. The most important challenge is thus differentiating between faults that require action and other disturbances. DG may also disturb the automatic re-closing. The operation sequence of protection devices during a fault is thus important. Due to DG, the existing methods used in fault location could also become inappropriate. [Mäk 07]

Protection problems may be eliminated or alleviated for example by proper co-ordination of protection settings [Mäk 07]. The co-ordination of feeder protection relays will improve the selectivity of feeder protection. This may also be achieved for example by directional over-current protection, distance protection or by communication based protection schemes which may be applied in more critical conditions. In order to avoid unnecessary disconnections of DG units there should be proper co-ordination of network and DG unit protection. DG unit protection should be slow enough to let network protection clear faults in the supply network or in the adjacent feeders, and at the same time it should be fast enough to disconnect DG units on faulty feeder.

When DG is connected to distribution networks there are multiple power sources and the assumption of unidirectional power flow is no longer valid. [Rep 05b] This raises new challenges for distribution network protection. There are cases where the feeder relay becomes blinded during a fault because of the fault current contribution of DG unit located on the same feeder with the fault. This problem can often be overcome by utilizing more sensitive protection settings. The more sensitive the settings are, however, the more prone to nuisance tripping the DG unit is during faults on adjacent feeders. When planning appropriate relay settings for the protection of a distribution network including DG, the planning engineers have to bear in mind that the protection will have to work properly also when DG units are disconnected [Rep 05b]. In addition to these problems the DG also brings with the problems related to islanding detection and failed reclosing problems. It is, thus obvious that special attention to protection coordination will have to be paid when connecting generation units to distribution networks in order to ensure safe operation. These protection challenges as well as the effect of system earthing and generator types on fault detection are discussed in this chapter.

2.5.1. Impact of DG on fault levels

Fault level is a good indicator for network robustness. High fault level signals from the nearness of a highly interconnected power system or of a generating station. The good thing about high fault levels is that on a feeder with high fault level, voltage profiles are very good (voltage drops are small) and rapid and reliable protection is easily established. There is, however, also a downside in high fault levels, namely the fact that the network components have to be dimensioned to withstand the high fault currents, which can be costly. A compromise between the robustness and dimensioning (costs) is thus desirable. [Wu 03]

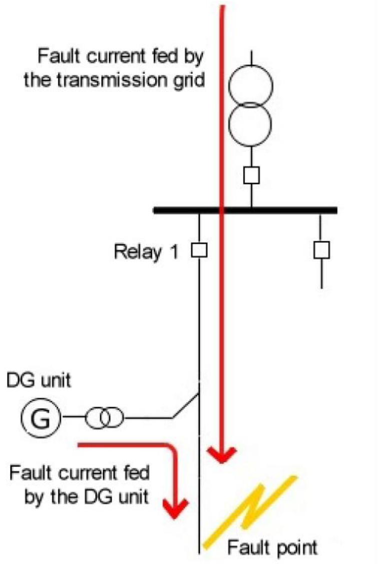
Both synchronous and asynchronous generator based DG contribute to fault currents. In some areas where the fault levels are already close to the switchgear current ratings, the connection of a DG unit may cause these ratings to be exceeded. The components whose ratings are exceeded can, of course, be changed to components with higher ratings but this is usually costly. The component upgrade costs are often allocated to the DG unit owner which may render the whole DG project uneconomical. [Jen 00]

Fault level contribution of a DG unit is dependent on a number of factors. The type of the generator and the way the generator is connected, for example, affect the form and the magnitude of the fault current as already discussed earlier. Converter connected generators feed much smaller fault currents compared to directly connected generators. The impedance between the generator and the fault point which is dependent, for instance, on the distance and configuration between the fault point and the generator, also affects the fault current magnitude fed by the generator. [Dti 05]

2.3.1. Protection blinding

The reach of an overcurrent relay is determined by the minimum fault current that will cause the relay to trip. This minimal current setting should be such that the reach of the overcurrent relay extends to the next recloser or covers the whole radial network downstream from the CB controlled by the overcurrent relay in case if no reclosers are used. [Dug 01] The presence of DG affects the reach of relays in certain situations. A situation where the operation of a protective relay is delayed or even completely hindered because of the fault current contribution of a DG unit is called protection under-reach or protection blinding. This might occur when a DG unit is feeding fault current parallel with the supplying substation as presented in figure 3.1. This being the case, the current seen by the relay protecting the feeder is reduced due to the fault current contribution of the parallel feeding DG unit. [Mäk 05]

Protection blinding is especially problematic when definite time characteristics in overcurrent relays are applied. In this case the feeder protection might become completely non-operational. In the case of overcurrent relays that are configured to use inverse time characteristics the feeder relay is not likely to be completely blinded but there is still the danger of delayed operation which might cause the thermal limits of lines and components to be exceeded. The blinding problem can be mitigated by setting more sensitive tripping values to the relays but this, on the other hand, might cause nuisance tripping during faults on the adjacent feeder, in extreme production / demand conditions or because of the starting currents of DG or other rotating devices. Constraining the DG unit operation and network reinforcements can also be used to mitigate the relay blinding problem but these increase the costs of DG unit and may therefore render the construction DG unit economically unfeasible. Changing the electrical parameters of the DG unit can also be used to tackle the blinding problem but this, of course, can only be done in the planning phase. [Mäk 05]



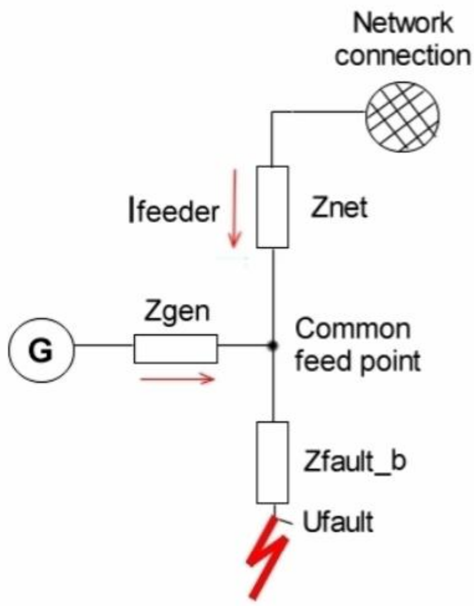


Figure 3.1. DG unit causing the blinding phenomenon [Mäk 05]   Figure 3.2. The idea of common feed point (CFP) [Mäk 05]

The theoretical background of the blinding phenomenon can be better understood with the help of the common feed point (CFP) concept which is illustrated in figure 3.2. The common feed point is the furthest point from the fault that is yet fed in parallel by the supplying network and the DG unit. If there was no DG unit in the network the fault current in the network model could be obtained from equation 3.2. The term Ufault stands for the voltage in the fault point just before the fault, whereas, the impedance Znet includes the impedance of the supplying network in addition to the impedance of the line between supply point and the common feed point. The impedance Zfault_b represents the impedance from the CFP to the fault point including the fault impedance. [Mäk 05]

$$I_{Fault} = \frac{U_{Fault}}{Z_{Net} + Z_{Fault\_b}} \tag{3.2}$$

Let us now consider that the DG unit is connected to the network as shown figure 3.2. The thevenin's impedance Zth can now be obtained by equation 3.3.

$$Z_{Th} = Z_{Fault\_b} + \frac{Z_{Gen} \cdot Z_{Net}}{Z_{Gen} + Z_{Net}} \tag{3.3}$$

With the help of this thevenin's impedance we can now calculate the feeder current seen by the relay:

$$I_{Feeder} = \frac{Z_{Gen}}{Z_{Net} + Z_{Gen}} \cdot \frac{U_{Fault}}{Z_{Th}} = \frac{Z_{Gen}}{Z_{Net} + Z_{Gen}} \cdot \frac{U_{Fault}}{Z_{Fault\_b} + \dfrac{Z_{Gen} \cdot Z_{net}}{Z_{Net} + Z_{Gen}}} \tag{3.4}$$

Which can be further reduced as shown below

$$I_{Feeder} = \frac{Z_{Gen} \cdot U_{Fault}}{Z_{Fault\_b} \cdot (Z_{Net} + Z_{Gen}) + Z_{Gen} \cdot Z_{net}} = \frac{U_{Fault}}{Z_{Fault\_b} + \frac{Z_{Fault\_b} \cdot Z_{Net}}{Z_{Gen}} + Z_{net}} \quad (3.5)$$

From equation (3.5) we can see that if the fault bus impedance Zfault_b equals to zero, the feeder current respectively equals to the fault current in the case where no DG was present. This, however, could only happen in case if a fault with no fault impedance would occur in the line connecting the supply and the DG unit. In reality there is always some fault impedance which means that the DG unit always affects the relay sensitivity. If the DG is disconnected from the network, the impedance ZGen will be close to infinity and the feeder current seen by the relay will again be equal to the original feeder current in the case where no DG was present. Let us still compare the original feeder current (equation 3.2) where no DG was present to the case where DG is present (equation 3.5). [Mäk 05]

$$\frac{U_{Fault}}{Z_{Fault\_b} + Z_{Net}} \geq \frac{U_{Fault}}{Z_{Fault\_b} + \frac{Z_{Fault\_b} \cdot Z_{Net}}{Z_{Gen}} + Z_{net}} \quad (3.6)$$

From equation 3.6 we can clearly see that the current fed by the supply is always less in the latter case is when the DG unit is connected provided that the fault impedance is greater than zero (which is always the case in reality). The extent to which DG unit interferes with the relay sensitivity is determined by the middle term, in other words, the ratio between the product of ZFault_b and ZNet and the denominator ZGen as seen from the equation (3.6). [Mäk 05]

2.3.2. Selectivity problems

Distributed generation can sometimes cause unnecessary tripping of the feeder where it is connected to. This kind of situation can happen in such a case where a DG unit is connected to one feeder and a fault occurs in some of the adjacent feeders fed by the same substation. This being the case, the DG unit feeds the fault on the other feeder through the substation bus and thus, of course, also through the relay protecting the feeder where the DG unit itself is connected. If the current fed by the DG to the fault is large enough, the relay, provided that it is not equipped with the directional protection feature, will consider that a fault has occurred within its protection zone and trips the feeder, where the DG unit is connected to, needlessly off. This is phenomenon which is called protection selectivity problem or sympathetic tripping problem is illustrated in the figure 3.3. Selectivity problems are likely to occur on situations where the generator on the first feeder and the fault on the other feeder are both located close to the substation. [Mäk 04] Also the type of the generator strongly influences to the likelihood of this problem. The fault current fed by induction generators usually decays quickly enough not to cause selectivity problems, whereas, synchronous generators can sustain a prolonged fault current which is more likely to cause problems. [Mäk 06b]

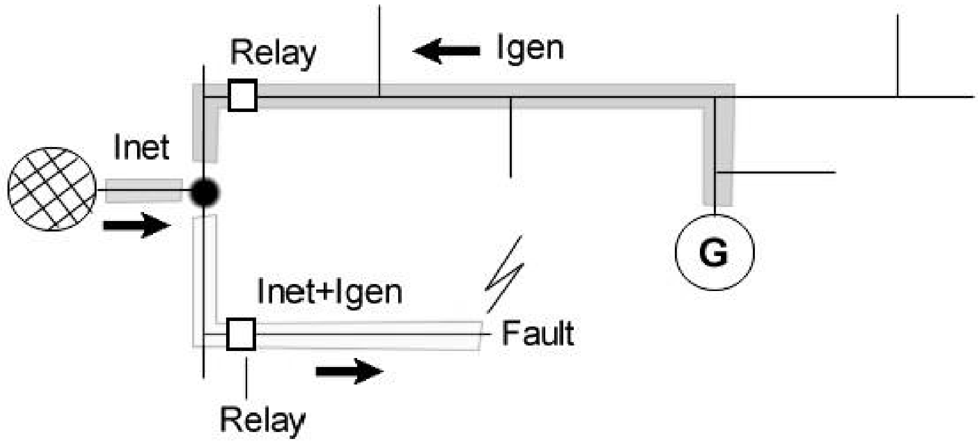


Figure 3.3. Protection selectivity problem caused by DG [Mäk 06b]

Selectivity problem could be tackled by utilizing directional relay protection which unfortunately is more expensive compared to non-directional relays. The problem could also often be avoided with proper relay settings. If the current setting of the relay cannot be changed, which is often the case, the problem can also be solved by utilizing appropriate operation times of the adjacent feeder relays. This can be done by setting the relay protecting the feeder where the DG unit is connected to, to operate slower than the adjacent feeder relays. If the latter alternative is preferred, care has to be taken that the delayed relay operation will not cause any thermal limits of network components to be exceeded. [Mäk 04]

2.3.3. Failed reclosing problems

Temporary faults, such as earth faults caused by lighting strikes on overhead lines, are generally cleared by automatic reclosing. Typically, in case if the first reclosing should fail, one or two more reclosings are made before the CB is ordered into permanent open position for the repair time. Automatic reclosing, however, becomes a bit more complicated in the presence of DG because the DG units will have to be tripped off the grid first before attempting to clear the fault with the help of reclosing. Otherwise the DG unit might keep on supplying and thus sustaining the arc. It is, therefore, necessary that all DG units are equipped with LOM protection that disconnect the DG units immediately after the connection to the main grid has been lost as already discussed in chapter two. The reconnection of the DG units into the re-energized network also has to be carried out with care in order to avoid dangerous stresses to the DG unit. This kind of coordination between the feeder protection and the protection of the DG units is quite challenging, especially in case if fast reclosing is applied. [Ple 03]

The application of longer CB open times or more sensitive LOM protection settings may sometimes be necessary to ensure correct protection sequence, although in some cases, the presence of DG may render autoreclosure completely unusable. Very sensitive generator protection settings also have the disadvantage that they may cause nuisance tripping of the DG unit. [Mäk 06b] A failed and a successful reclosing sequence are illustrated in figure 3.4.

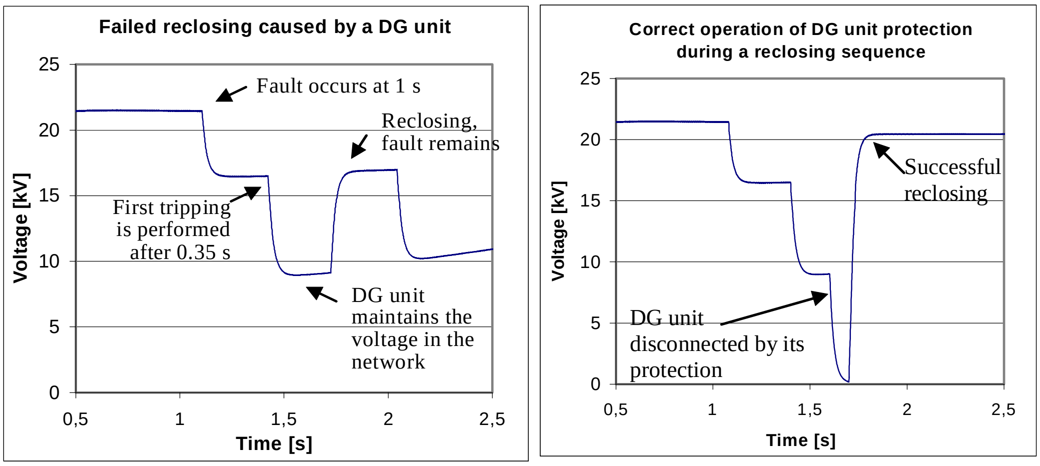


Figure 3.4. Reclosing problems caused by DG [Mäk 06c]

The left figure illustrates a failed reclosing sequence, whereas, the right figure shows a successful one. In the left figure, a DG unit connected to the feeder where the autoreclosure is applied maintains the voltage during the CB open time causing the reclosing action to fail. In the right figure, on the other hand, the LOM protection disconnects the DG unit in time and the network is thus de-energized resulting in a successful reclosing.

2.3.4. The influence of the DG unit type

The behavior of a DG unit during faults is strongly influenced by the DG unit implementation and type of the generator applied. The generator types can roughly be divided into three groups which are induction- and synchronous generators and installations applying static power electronic converters. A generator of some kind may also be connected to the last mentioned one but the converter dictates the behavior of such an installation. [Mäk 06a]

Synchronous generators are widely applied in small scale hydro-, CHP-, reciprocating engine based power plants but also in some converter connected wind power installations. These generators are usually designed to be able to feed prolonged fault currents to the network during faults which, on the one hand, is harmful to the network but, on the other hand, makes the fault easier to detect. [Mäk 06a] Figure 3.5 illustrates the typical form of a fault current fed by a synchronous generator. As it can be seen from the figure, the fault current usually decays to some extent after the initial peak but the field forcing feature can raise the current a bit after a couple of seconds.

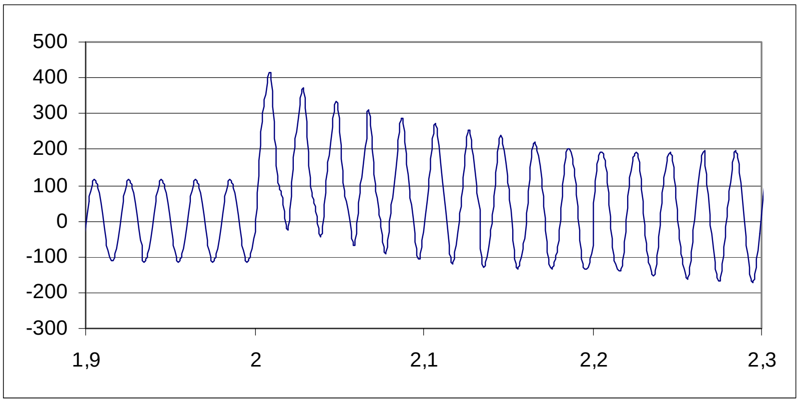


Figure 3.5. Typical form of a fault current fed by a synchronous generator [Mäk 06a]

Induction generators are applied in wind power installations and in micro-scale hydro power plants [Mäk 06a]. Unlike synchronous generators, induction generators are not capable of supplying continuous fault current during three phase faults because the reactive power supply required to sustain the excitation of the induction generator is interrupted in such faults [Jen 00]. Figure 3.6 illustrates the form of a fault current fed by an induction generator. The initial fault current fed by this generator type is roughly the same compared to the one of a synchronous generator. However, the fault current fed by induction generator decays strongly after the initial peak in symmetrical faults. [Mäk 06a]

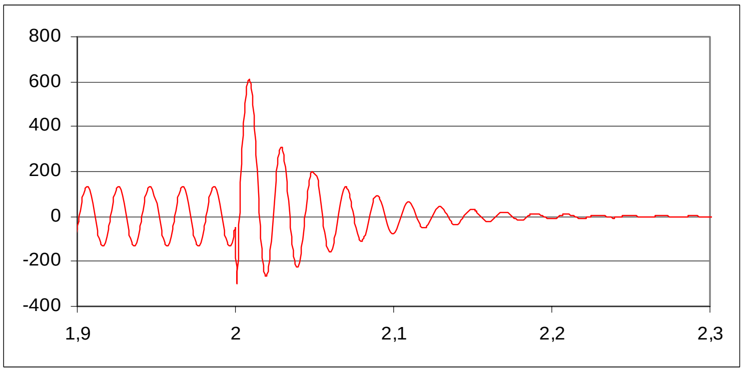


Figure 3.6. Typical form of a fault current fed by an induction generator [Mäk 06a]

Power electronic devices such as converters can be used to obtain better control and efficiency of a power plant. [Mäk 06a] The better efficiency stems from the fact that the DG unit is allowed to rotate at whichever speed that is optimal for it when converters are used. Converters are also used for inverting the DC generated by some energy sources like photovoltaic and fuel cells. [Jen 00] The power electronic interfaces dictate the fault current characteristics even if traditional generators are used. Generally implementations using power electronics can only feed an initial peak current which is shortly after rapidly cut down. It is, however, possible to build devices capable of feeding continuous fault currents as well. [Mäk 06a] The dimensioning of the semiconductors used in the converters determines how large currents the converter can feed. Overdimensioning of the semiconductors is, however, not the common practice because of their high cost [Mac 03].

2.3.5. The influence of DG on earth fault protection

The main purpose of system earthing is to protect network components, operational staff, general public and property in general. Generally four different types of earthing arrangements are used in electrical networks. These are direct earthing, earthing through impedance, earthing through suppression coil and isolated earth system. The way by which the system is earthed affects the behavior of the system in unsymmetrical faults. Generally one can say that the lower the earthing impedance, the higher the earth fault currents and the lower the overvoltage during earth faults. In directly earthed systems the earth fault currents can actually exceed the short circuit fault currents, whereas, in systems with isolated earth the earth fault currents are often even smaller than the load currents. [Lak 95]

The suitability of various types of earth fault protection is dependent on the type of the earthing applied in the network and the required sensitivity and selectivity of protection. Conventional earth fault detection methods cannot be applied in network with isolated earth or in networks that are earthed through arc-suppression coils because the earth fault currents in such networks are very small. Earth faults in such networks, however, cause asymmetry in both voltages and currents and not just on the feeder where an earth fault has occurred but on the whole distribution network fed by the same main transformer. These asymmetries can be applied for the detection of earth faults. The zero voltage is measured at the substation bus and the currents at the feeder relay measurement points. Since the whole network is affected by the fault the feeder relays will, nevertheless, have to be equipped with the directional earth fault feature in order to discriminate on which feeder the fault has occurred. [Lak 95]

At present, the common practice is to leave the earth fault protection of DG units to be undertaken by the LOM protection. This means that the DG unit will only be disconnected after the formation of an island caused by the opening of the feeder relay. This arrangement can sometimes be problematic because of the NDZ of the LOM protection. [Mäk 07c] Long term islanding is a rare event because it is only possible when both active and reactive power production and consumption are in equilibrium. Momentary islanding lasting few hundred milliseconds, on the contrary, is a common phenomenon. [Kum 05] The fact that LOM protection will probably not operate instantly after the operation of the feeder relay but with a certain delay is problematic in the sense that the DG unit in the islanded zone can sustain the earth fault which results in dangerous step and touch voltages. Faster disconnection of DG unit is thus desirable. In the case of earth faults, this could be achieved by adding earth fault protection to the DG unit interconnection point. [Mäk 07c] This, however, is often problematic because DG units are commonly connected to the network through delta-wye type block transformers which create a point of discontinuity to the zero sequence network. Because of this point of discontinuity the zero sequence network values at the LV side of the transformer cannot be utilized for detecting earth faults in MV network. [Kum 05] The point of discontinuity in the zero sequence network also means that the presence of DG does not interfere with the operation of feeder protection in earth faults which, on the contrary, is the case with short circuit faults. [Mäk 07c]. The MV side values of the block transformer, however, could, in some cases, be utilized for detecting earth faults. The use of the MV side values for the earth fault protection of a DG unit is a promising solution if the DG unit is situated close to the block transformer. This idea might, nevertheless, not be quite so promising if the DG unit is located further in the LV networks because this would necessitate costly communication between the DG unit and the transformer station. [Kum 05]

2.4. Steady state impacts of DG

2.4.1 Impact on voltage levels

Distribution network utilities have the obligation to maintain the network voltages within predefined levels. At present, this is mostly done controlling the tap changer(s) of the main transformer(s) and by building a strong network. In a network where there is no generation connected, the highest voltage can be found from the substation bus and the lowest voltages from the end of the feeders. [Jen 00]

Traditionally, the voltage drop at the end of the feeders has been one of the principal dimensioning constraints in network planning. The deepest voltage drop on a feeder occurs during maximum demand situation when there is no generation connected to this feeder. Some new dimensioning factors, however, need to be included when DG is present. These new dimensioning factors from the voltage level point of view are maximum DG production combined with minimum demand and minimum DG production combined with maximum demand. For a lightly loaded distribution network the approximate voltage rise due to DG can be obtained from equation (3.1), where R and X are the resistance and reactance of the circuit, P and Q the active and reactive power of the DG and V the nominal voltage of the circuit. [Jen 00]

$$\Delta V = \frac{(PR + XQ)}{V} \qquad (3.1)$$

Problems related to voltage levels are typically found from weak rural networks. Urban networks are usually stronger and shorter, and thus, rarely suffer from problems related to voltage levels. Increased fault levels may, however, sometimes become a problem in urban networks when DG is present. [Dti 05]

The control of DG unit voltage instead of unity power factor requirement will help network development and operation in weak networks [Rep 05, Lie 02]. This does not require new technical innovations but a new way of thinking. The co-ordination of voltage controllers (e.g. automatic voltage regulators (AVR) of on-line tap changer (OLTC) and DG units) will further improve the situation which however requires some additional measurements for state estimation purposes [Rep 05]. Other consequences of voltage control are increased reactive power flow and network losses which may be influenced by the co-ordination of controllers.

2.4.2 Impacts on power flow

The production of electricity close to consumers will reduce the transfer of electricity. This will also affect network losses. Network losses may also increase when a large DG unit, e.g. wind farm, is located far from consumption and the electrical distance of transferred electricity increases compared to situation without a DG unit.

The change of the losses in distribution networks due to DG is dependent on factors such as the location of a DG unit in relation to the loads, the thickness of conductor used, the production in relation to consumption and the timely correlation between production and consumption. The distribution losses will decrease if a DG unit is connected to a feeder where the consumption exceeds the production of the DG unit. The distribution losses, on the other hand, will increase if a DG unit is located on a radial feeder dedicated to production only because in this case the power fed by the generator will first have to flow to substation and only then to the loaded feeders. A DG unit connected to substation bus only affects the losses occurring in the main transformer in the MV network side. The losses in the HV network are usually decreased due to DG. [Rep 05b]

The intermittent (non-dispatchable, uncertain and uncontrolled) production in passive distribution network does not benefit network rating. The loadability of distribution network is determined by voltage profile (decrease or rise), power quality and thermal ratings. The intermittent production in weak rural distribution network may cause voltage rise problems. The dimensioning of network becomes quite challenging when there are different size and type of DG units along the network. The worst case planning principle of DG interconnection in passive networks should be replaced with a statistical planning approach in active networks [Rep 05]. The increment of fault current level due to new DG units may cause major investments in urban networks if the rating of components is exceeded. In opposite case increasing fault level is acceptable because it will improve customer' quality of supply by reducing the magnitude of voltage disturbances. The voltage control or reactive power capability of DG units could also be utilized in network management.

In extreme network conditions power flow management (e.g. production curtailment or generation constraints) may also be applied due to limitations in network capability [Rep 05, Col 03, Rep 06]. Normally all network customers have firm network capacity available. The non-firm network capacity is however much higher than firm capacity which enables to increase the amount of generation to be connected and operated under normal network conditions, but the generator will face up to constraints in extreme conditions which are not considered in the rating of firm capacity. The extreme conditions may be e.g. exceptional switching states of network or variety of intermittent DG units producing maximum power during very low demand. The probability of extreme conditions should be low enough in order to have economically attractive solution. This is a similar approach than load shedding due to thermal limitation or voltage decrease in extreme high load demand conditions. If DG units are used as a means to increase the firm network capacity, active resources should be controlled almost in real-time to reduce power transfer at overloaded part of network.

3. PLANNING OF ACTIVE NETWORK

Traditional network planning guidelines are not changed in active networks. The physical reality in the form of Ohms law still exists. However the distribution network operation may change due to new automation, control and communication possibilities which must also be considered in network planning.

The amount of planning efforts needed for the active network planning should not be remarkably higher than that for a traditional solution. Without solid support of planning tools from distribution network analysis tools to integrated information systems (e.g. network information system (NIS), customer information system (CIS), asset management system, etc.) for the planning tasks of active network characteristics the basic solution in network reinforcement tend to be the traditional and well proven passive network solution. The number of open questions like what protection scheme is applied in feeder protection when feeder includes loads and DG should be zero in planning phase. A specific planning issue requires the existence of company policy or planning guideline in the form of applied technology and solution examples in order to widen the information of active network characteristics for planners.

3.1. ANCILLARY SERVICES

The second important issue of active network planning is the contract and operational issue of customer owned devices. The assumption is that the amount of customer owned controllable devices will increase and those are participating in network operation. The operation of customer owned devices might be organized via ancillary service markets when the location of service provider (device) does not have great influence on power system functioning. These services are e.g. balancing and regulation power which are however not needed in distribution network operation. The liquidity of localized ancillary service market might be poor therefore ancillary service markets are not expected to operate on distribution network level in the near future.

Because the active resources have a central role in the ANM, there should be a solid mechanism to bring these resources available for a DNO. Two main approaches for this purpose are the market based and the grid code based approach. The market based approach relies on ancillary services bought from an ancillary service market like the regulating power market or from a dedicated contract between the resource and the DNO like reserve contracts today [Fin 08a]. The idea of the grid code approach is to share the responsibilities needed in power system operation between the users of power system [Fin 08b]. This approach was typically applied in vertically integrated power companies. The separation of production and network businesses however radically changed the applicability of that approach. The concept of ancillary service market was introduced to share the responsibilities of power system operation in a transparent and cost based way in open energy market condition. The present view of power system operation is such that both of these approaches are needed to achieve efficient and economical power system in overall.

Ancillary services are not commonly applied in distribution network operation today although there are no restrictions for their application. The application of local reactive power or voltage control service would be straightforward in distribution network. The power flow management service could be based on similar approach than the counter-trade principle to release transmission network bottlenecks inside a price area in Nordel [Nor 00]. The island operation would require many services like black start, frequency control, primary and secondary reserves and voltage control. Ancillary services like local voltage and frequency control could also be realised through direct load control [Pan 01].

The participation of localized ancillary services like power flow management, reactive power support and voltage control into distribution network operation is realized by an ancillary service contract between DNO and service provider. The contract defines a standard requirement for the performance of controllable device and the payment basis for the availability and use of service. If certain ancillary service is required from almost every DG connection, it is better to include that into DG connection requirements.

Normally network customers have a firm network capacity available which is guaranteed in all network loading conditions by network itself. When a single large and intermittently behaving customer like a wind farm is connected to weak distribution network, there may appear extreme loading conditions (combination of demand and wind production) which restrict the size of wind farm remarkably in the existing distribution network. If the cost of network reinforcement to achieve the firm network capacity for the wind farm is large compared to the probability of extreme conditions, it may be favourable opportunity for both the network and the production company to utilize ancillary services for network management during these extreme situations. The benefit of e.g. occasional production curtailment comes from the fact that the non firm network capacity, i.e. the amount of DG to be connected and operated under normal network conditions, is most of the time much higher than the firm capacity. Of course the drawback of production curtailment is the loss of otherwise produced energy in case of extreme loading conditions. The ancillary services like the reactive power support of DG unit may also be utilized to alleviate network reinforcements in weak distribution networks.

3.2. DISTRIBUTION NETWORK PLANNING

Distribution network design is traditionally based on the so called worst case planning principle. In radial distribution networks, where no DG is present, the limiting worst case factors are derived from the voltage drop at the end of the feeder, which occurs during maximum load at the feeder, and the thermal limits of the conductor used. [Lak 95] When DG is present in the network, the worst case will occur in a combination of minimum DG production together with maximum load. In lightly loaded networks, the presence of DG, will however, introduce also another limiting worst case factor. This is the combination of maximum DG production together with minimum load, which might cause the maximum allowable voltage to be exceeded at the DG interconnection point of the feeder line. [Jen 00]

The worst case design principle has been considered satisfactory in networks where only few relatively large DG units are interconnected. The validity of this principle is, however, no longer that clear when a large amount of DG units based on various kinds of energy sources are interconnected to the distribution network. This is because it is quite unlikely that all the units would be operating at their maximum output limits at the same time. The worst case principle is, therefore, a fairly conservative design principle for networks with a high DG penetration level. [Rep 05]

3.2.1. Protection planning

Protection is an essential part of distribution network planning as it always involves safety of the system. Integrating DG to the network brings new challenges that must be considered during the DG interconnection planning process. As the amount of DG is forecasted to increase rapidly, it should be handled efficiently in the near future. Thereby protection impacts of DG should become integrated to the planning system applied normally by network operator.

The protection impacts can be shortly categorized as follows:

- Risk of undetected faults or slow protection. The contribution of DG may result in reduced fault currents seen by the feeder relay and further in delayed or blocked operation of protection. Serious safety hazards may occur as a result.
- Unnecessary operations of protection. This may relate to wrong operation of feeder protection or DG connection point protection. There are no actual safety problems, however this problem results in additional service interruptions of customers and must thereby be avoided.
- Failing autoreclosings. Where fast autoreclosings are applied, they may fail if the DG unit is not disconnected fast enough. Failing fast reclosing results in a longer reclosing and a service interruption to customers.
- Unintended islandings. Due to safety and power quality consequences, all island situations that are not planned must be avoided.

Studying the possible protection impacts of DG and the operation of protection requires multiple fault cases with different fault locations and fault types. Thereby needed calculations are suitable to be performed automatically by network information system. The automatic fault calculation based on modern network information system consists of following ideas:

1) Protection planning procedure. Point-by-point calculation, which goes through network nodes and repeats the fault calculation. Results are saved and analysed afterwards.

2) Fault calculation extension. Iterative approach for including the dynamical behaviour of DG. Idea is based on repeating the fault calculation and adjusting the generator values between these steps. Different DG generator types can be modelled with this relatively simple approach.

3) Protection requirement graph. Graphical presentation of calculation results. The idea is to present the operation area for DG protection.

Methods are planned to integrate to network information system and to use the normal fault calculation. Figure 3.1 presents the general co-operation of methods.

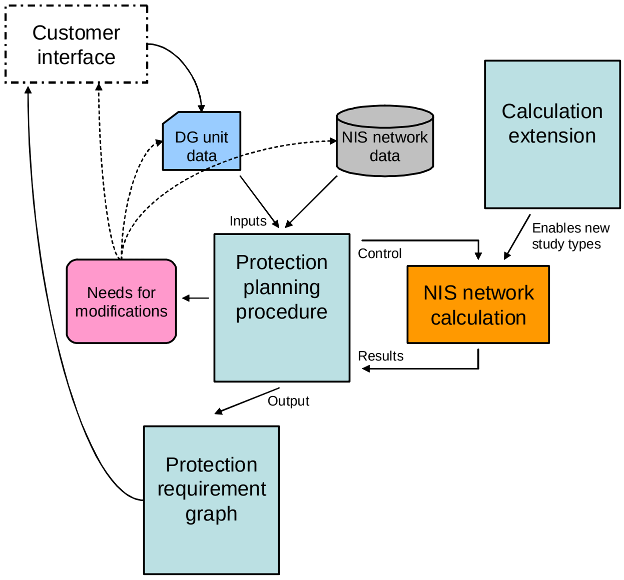


Figure 3.1. Developed methods and their connections.

3.2.2. *Example of protection planning*

Probably the most important benefit of developed methods is the possibility of studying the dynamic behaviour of DG unit as a part of normal steady-state fault calculation. This feature is not intended for offering accuracies similar to dynamic simulations, but to assist in protection studies.

A good example of using the methods is the possibility of studying the blinding impact. When a DG unit is connected along a distribution feeder, the feeder relay sees smaller fault current and may operate with delay or even become totally blocked. This impact depends on the generator type and characteristics.

Figure 3.2 presents a typical situation. Higher black curve shows the normal feeder fault current without any DG connected. There is an inrush peak and a steady remaining fault current. The lower black curve indicates the situation after installing DG unit somewhere along the feeder between the relay and the fault. As it can be seen, in the subtransient state there is a major difference in fault currents. However, transient and mainly steady state currents are the ones that affect network protection. In this case, there remains a difference in the steady state as well. This is the essential “blinding” impact. The intensity of blinding depends on the combination of network strength and generator characteristics, but similar behaviour can be observed in each case.

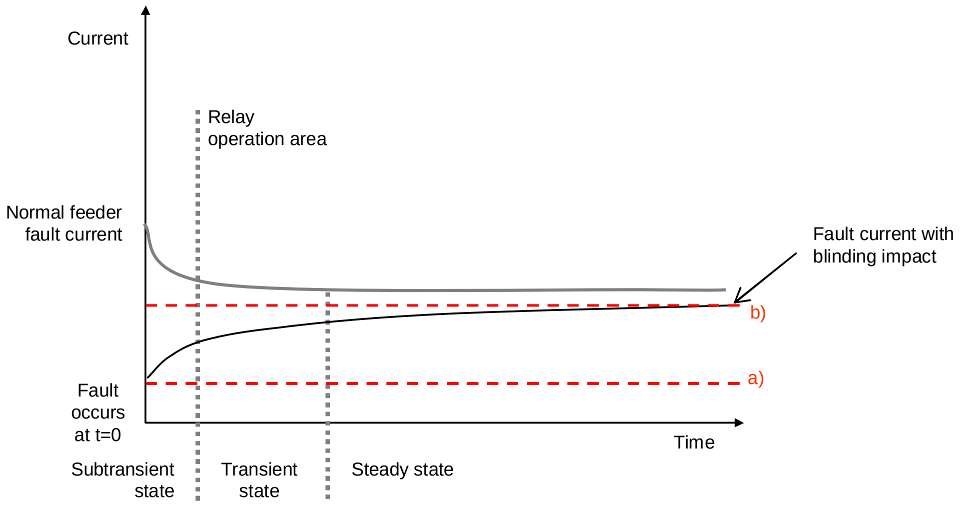


Figure 3.2. Example of feeder fault current and blinding impact.

What is important in the above figure are the red dotted lines a and b. These are the possible results of the traditional fault calculation in network planning systems. Actually, in the most typical situation the fault calculation does not take the DG unit into account at all. Hence options a and b as such are already good results.

However, it is possible to make the results more accurate with the extended calculation method. This method can enable analysis of subtransient and transient states as well. Figure 3.3 presents one example for a realistic calculation case. In this figure the calculation steps used in the calculation looping can be seen easily, however the output could yet be fixed with simple interpolation. With this version it would be possible to assess for instance the operation sequences or delays of protection devices.

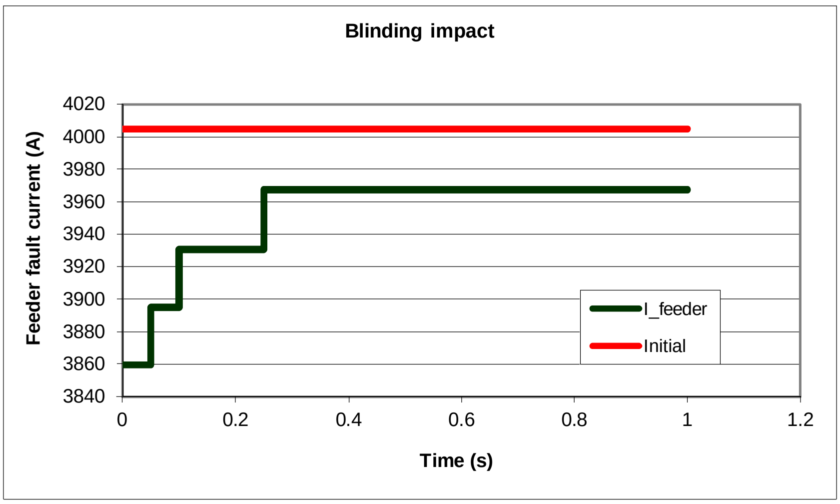


Figure 3.3. Result for a realistic case with normal calculation and the modified one. [Adi 10b]

3.2.3. Stochastic planning methods for distribution networks including DG

Statistical planning offers a more fair way for assessing the allowable DG penetration level. In this concept, the load curves used in the NIS are extended with DG production curves. Due to a lack of actual measurements in network planning phase and heavy dependence between power production and the location of the DG unit, the production curves are based on long-term statistics of wind speed or temperature. By performing a load flow calculation from the data obtained from the two combined curves, it is possible to simulate the hourly functioning of the network. The correlation of power production and load demand is a very critical issue in network planning. For example, the operation of CHP unit and load demand correlates very well, hence the worst case planning principle is simply too conservative.

The planning of the distribution network is not restricted to certain fictive planning conditions, but a series of hourly conditions is considered. The load flow simulations are used to analyse what kind of network conditions might exist. Load flow calculations can be used to find out the limiting network constraints and their duration. They can also be utilized for DG interconnection studies, and furthermore, for the comparison between network reinforcement and ANM strategies. The hourly load flow information can also be helpful in estimating the DG interconnection charges. When a number of different production curves are used in load flow simulations and the simulation results are examined together, the method will converge towards probabilistic load flow simulation e.g. Monte Carlo simulation. [Rep 05]

The purpose of the non-firm interconnection is to allow a higher DG penetration by increasing the distribution network transfer capability. The firm interconnection is always available and calculation of interconnection capability is based on the worst case planning principle. The increased transfer capability of non firm interconnection, in turn, is achieved by using the network more precisely. This is done by utilizing the DG units e.g. voltage control or production curtailment when the network constraints occur occasionally. Ancillary service contracts between the DG unit owners and the local DNO are, of course, required to provide the controllability of the DG units for the DNO. Figure 3.4 represents an example of stochastic nature of DG and its effect on network voltage. [Rep 05]

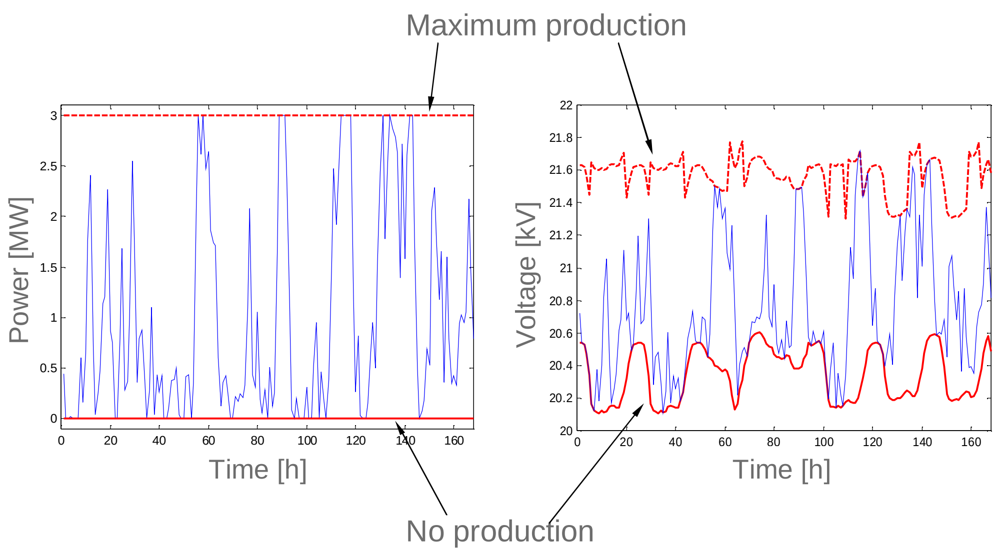


Figure 3.4. Example of hourly time series of power production and connection point voltage.

The network transfer capability from the DG point of view is heavily dependent on loading conditions in the distribution network. The utilisation of an existing MV network may be improved in the case of a DG unit interconnection if the operation of the DG unit is not totally independent of network conditions [Lay 02, Mas 02]. The control of DG unit output power is beneficial, if network constraints appear occasionally, e.g. voltage rise problem during light loading and high production. The probability of this kind of network condition is very rare and may be evaluated based on e.g. load curves and wind statistics or measurements.

If the enforcements of the MV network are based on the worst case this might introduce a severe economic barrier for a DG interconnection in weak distribution networks due to excessively conservative principles. The non firm planning principle may allow higher penetration of DG in a distribution network with less network investments and connection charges than with the firm worst case planning principle. The non firm interconnection may benefit both the network and the production companies by allowing higher penetration of DG with less network investments.

3.2.4. Example of non firm interconnection of wind farm in MV network

An example of interconnection of 3 MW wind farm into MV network (20 kV) is presented with a real life distribution network of Fortum Sähkönsiirto Oy in south-west Finland, where the voltage rise problem is acute if the planned wind turbines are constructed. The load flow calculations were made for an average year based on hourly load demand and production estimates. The simulations cover 8760 hours. The wind turbines are connected 22 km away from the substation and they are equipped with permanent magnet generators and frequency converters in the stator circuit, which allows power factor control between 0.92–1.00 inductive or capacitive.

Figure 3.5 presents the network transfer capabilities at wind farm connection point. The results are presented regarding the load demand of the feeder including wind farm. The results are presented for three different voltage level management concepts and for firm and non firm interconnection. The capability of firm interconnection is calculated based on the worst case planning principle. The present situation, where the firm interconnection is used with unity power factor at the DG unit site is very conservative and the utilisation of network capability is very low. The worst case planning principle is suitable for traditional distribution network planning but it is not capable of considering system wide aspects when DG is integrated in the distribution network. The main advantage of non-firm interconnection is its capability to take into account network loading condition and enhance the network transfer capability when possible. The advantages of voltage level management concepts are also very clearly seen in Figure 3.5. [Rep 05]

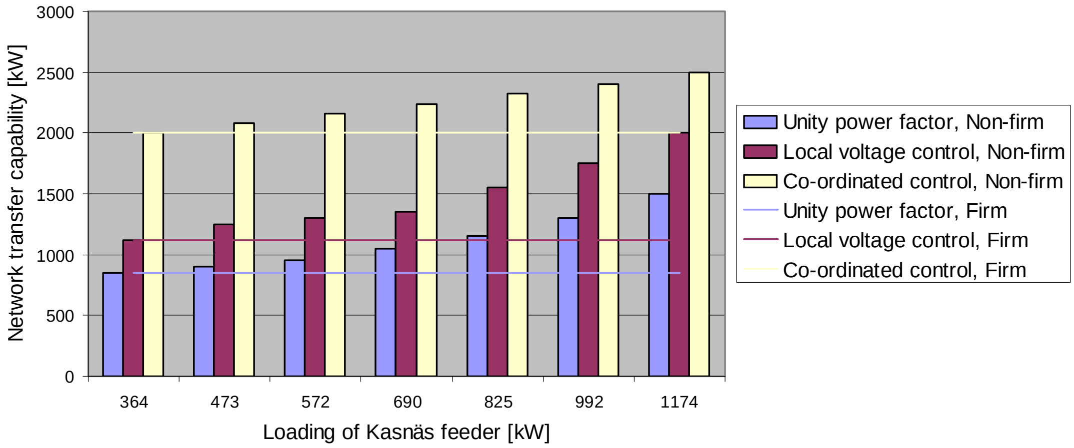


Figure 3.5. Distribution network capabilities.

Figure 3.6 shows the amounts of energy not produced by a 3 MW wind farm. The wind power is curtailed due to voltage rise effect in MV network during high wind power production periods. The total available production is 9109.1 MWh, which is calculated from simulated wind. The difference between firm and non-firm interconnections may also be seen in this figure. Similarly the effect of voltage level management concepts may be seen.

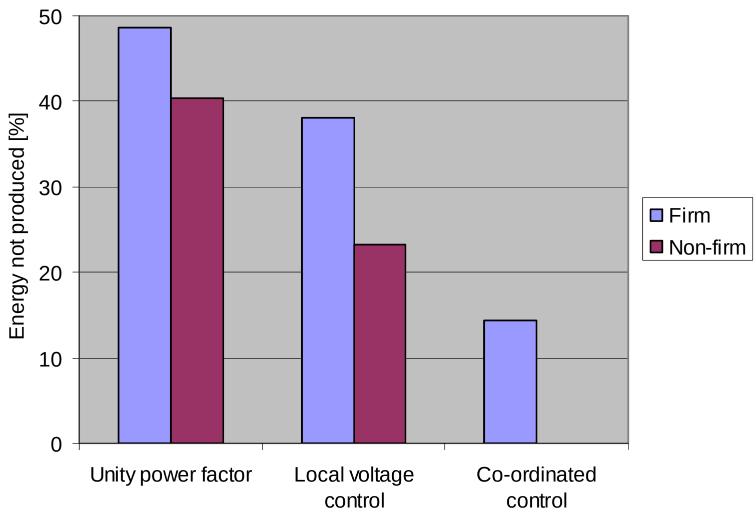


Figure 3.6. Energy not produced due to wind power curtailment.

Figure 3.7 is one more presentation for the unity power factor conditions. The duration curve of distribution network transfer capability is quite flat but it has clear minimum and maximum. The minimum value of network capability, which is also the interconnection capacity of the worst case planning principle, is 815 kW. The maximum value of network capability is 1500 kW.

There has also been presented two duration curves for the production units. The firm interconnection (production fixed) may utilise only the minimum capability of the network, because there should always be capacity available at the network for any amount of power production at any time. That's why the capacity of wind farm should be equal or less than the minimum value of network capability. The total amount of energy production during a year is 2497 MWh which correspond capacity factor 0.35. The amount of energy not produced is zero.

The non-firm interconnection (production flexible) is presented for the extreme condition which is the maximum value of network capability. In this case the network constraints are removed by production curtailment to avoid over-voltages at the connection point. The total amount of energy production during a year is 3967 MWh which correspond capacity factor 0.30. The amount of energy not produced is 629 MWh.

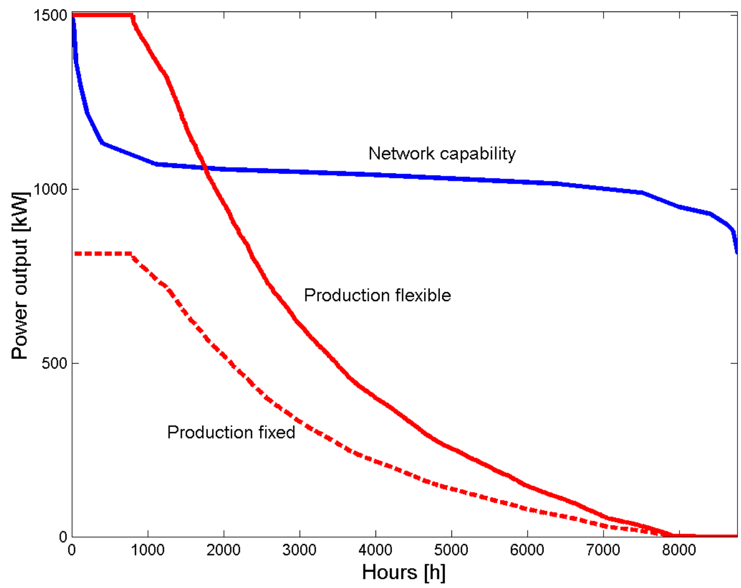


Figure 3.7. Duration curves of network transfer capability and wind power production.

4. ACTIVE NETWORK MANAGEMENT

The rapidly increasing amount of DG is raising new challenges to distribution networks. Protection issues, voltage rise problems, power quality problems and raising fault levels are the most serious of these challenges caused by DG. These problems can greatly restrict the popularity of DG if distribution networks are managed passively as today. The basic characteristics of passive network management are the simple network reinforcement approach by which it creates extra capacity and the way of treating generation units merely as negative loads (fit and forget philosophy). The problem with this kind of replacement strategy is that it causes very high costs which, depending on the cost allocation, can render DG economically unfeasible.

The problems caused by DG to distribution networks can often be fixed by just simply changing existing network components to new ones with higher ratings. This traditional way is, however, just simply too expensive and it leads to a fairly low utilization rate of the network assets. Instead of this traditional passive way of operating distribution networks, networks can alternatively be managed in a more intelligent manner. This is done by intelligently controlling the various existing active resources such as DG units, controllable loads, reactive power compensation devices, energy storages and the tap changers of HV/MV transformers in such a way that these resources support the network. This approach, which is called active network management (ANM), does not necessarily require any investments on primary network components like conductors and transformers since the existing capacity is used more precisely. Investments on secondary components like local controllers, network management systems and communications are, however, needed. The benefits brought by the active management will, nevertheless, very likely outweigh the costs of the investments on secondary network components.

The network management concept presented here is based on existing distribution network management concept completed with new features and functions. The existing distribution network management concept is a complex system of devices, automation systems and practices which include protection relays, controllers, telecommunication, substation and feeder automation systems, control centre software like SCADA and DMS, and guidelines for network planning and operation. Network management includes the automation of network operations like automatic supply restoration and the increment of observability and controllability of distribution network via measurement, control and communication.

From network management point of view the increasing amount of DG is often seen as negative development, which brings the complexity of transmission network to distribution network level. However the integration of DG in distribution network will benefit the network when managed appropriately. When the distribution network is managed according to the ANM method the interactions of different active devices can be planned and controlled to benefit the operation and stability of the network. With proper interaction of devices the overall system performance can be improved from presently used practices. The new distribution network is called as an active distribution network.

The new features and functions of distribution network management are based on the control and cooperation of active devices. The goals of developed ANM method are to ensure safe network operation and to increase network reliability in networks with DG, to maximize the utilization of the existing networks with bottleneck caused by voltage issues, and to maintain the required level of power quality despite non predictable power production or consumption. In order to achieve these goals there is needed to develop individual technical solutions (protection, voltage control and STATCOM) and validate the combination of technical solutions (ANM method).

Next the control hierarchy of active distribution network and its management system is introduced. After that each control level is discussed in detail and results achieved during ADINE project are described from ANM viewpoint.

4.1. CONTROL HIERARCHY OF ANM

The management of active network does not in principle differ from the management of passive network. The only difference is that the management software and automation devices become more complex and intelligent. The management will at least in short-term perspective be based on SCADA/DMS and substation and feeder automation systems.

The controllability of distribution network has been mainly restricted to primary substations (SCADA, substation automation and voltage regulators) while the utilization of distribution network automation (feeder automation, fault location and fault restoration) is concentrating on network reliability improvement. The monitoring and telemetry of MV and low voltage (LV) networks is still very limited although the number of secondary substation monitoring devices and AMI is increasing rapidly. The need for real-time information about the status of DG units and their production is becoming more important when the penetration level of DG is increasing or when a DG unit has strong local influence. The local intelligence at substation via processing and communication capability of intelligent electronic devices (IED) will also increase in the future. This will change the roles of substation automation and SCADA/DMS in some extent. Some of the network management functions currently implemented in SCADA/DMS might be part of substation automation e.g. when an island operation within the Power cell concept is going to be applied.

The existing control hierarchy includes three levels: protection system (fastest and autonomous), automatic control system and area control levels. Typically ANM concepts add new features for all these levels. New protection system features in distribution network are e.g. distance and differential protection schemes. The ANM concept includes at automatic control system level local voltage and frequency control, load shedding and production curtailment features. ANM concepts add many new features for the area control level. The area control level includes co-ordination of voltage controllers, power flow management, automatic network restoration and island operation.

Figure 4.1 visualizes the control levels of active distribution network and how the ANM method is affecting them. All hardware devices like protection relays, AVR of tap changer, AVR of DG units, STATCOM controller and power factor controller of reactive power compensation are basically working in decentralized way. They get measurements from local measurement devices and operate based on this information. This is a decentralized operation of protection and control like they are operated today. However the locations of protection and control devices are not limited to primary substation but they may locate along the distribution network. Some control devices like DG or STATCOM may also locate on customer side.

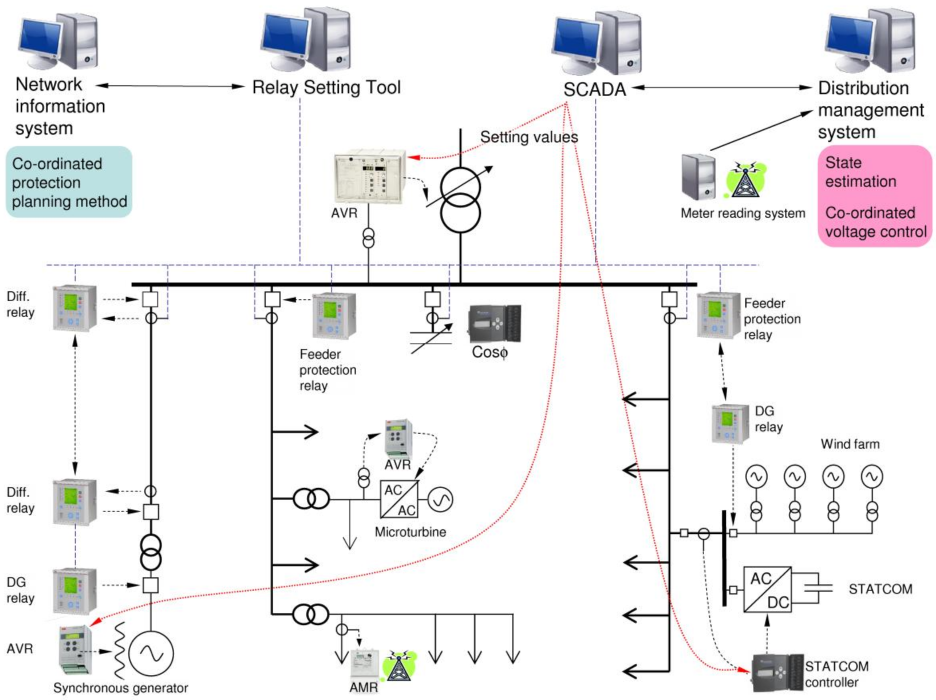


Figure 4.1. Overview of the active distribution network in the ADINE project.

Protection relays are working on the lowest level like in passive networks, but new feeder protection schemes like directional over-current, distance and differential protection, communication based protection schemes and new fault location applications are introduced in order to take into account the influence of DG on protection.

Automatic voltage regulation (AVR) of DG units, AVR of OLTC, STATCOM controller and power factor controller are operated in decentralized automatic control system level. The new issue in ANM is the utilization of automatic control systems in distribution network operation greatly.

On the top of the decentralized control system there exists also a centralized system for distribution network management. The basis of this management system is the control centre information system and communication between control centre and decentralized equipment. The information system consists of SCADA, DMS and Relay setting tool used in network operation and NIS used in network planning.

The ANM method is a conceptual description of the management of an active distribution network. It is capable of applying any communication medium and protocol but is however restricted by capabilities of individual devices and software. Naturally the whole system would be cheaper, simpler, and more scalable, if multi-functional and vendor open interfaces (e.g. IEC 61850) and data models (e.g. IEC 61970 and 61968) are applied at information exchange.

4.2. PROTECTION SYSTEM

The protection system is the first of the distribution network control hierarchy levels. [Rep 08] Its task is to make sure that power system is operating within its normal limits. If a system hazard, say a short circuit, should occur, the protection system must reliably remove the faulted part from the rest of the network and restore the best possible conditions that are available. The protective actions have to be undertaken automatically and rapidly enough in order to avoid further damage. [And 99]

The increasing amount of DG is raising new challenges for the distribution network protection system. Protection misoperations can lead to dangerous situations and cannot, therefore, be tolerated. [Mäk 06a] In order to overcome these challenges, new ways of network protection need to be considered. Distance and differential protection schemes are now being considered as possible solutions to challenges raised by DG in the distribution networks. [Rep 08] Directional overcurrent scheme and sectionalizing circuit breakers could also be used as a means to counter the new protection challenges. [Kum 06a] ADINE project has developed new protection solutions that are able to take into account the contribution of DG units. New coordinated planning method for studying the operation sequences of the protective IED's in networks including DG are also developed and taken into pilot use. [Adi 08b]

There has traditionally been very few if any generation units connected to MV distribution networks. The fault current flow in distribution networks has, therefore, been unidirectional which has enabled the utilization of relatively simple protection schemes. DG, however, can change the magnitudes and directions of fault currents in distribution networks which complicates the situation from the network protection point of view. The fault current contribution of DG units can, for example, cause protection blinding, protection selectivity and failed reclosing problems. These problems can be solved by substituting commonly used non-directional overcurrent relays by more advanced protection schemes such as directional overcurrent-, distance-, and differential protection. The selectivity of short circuit protection could be improved with directional over current or distance protection. The selectivity of differential protection is ideal in theory but the utilization of that scheme is limited to special cases in distribution networks. The sensitivity of feeder protection may be improved with distance and communication based protection schemes.

The studies carried out by utilizing real commercial IEDs in a real time simulation environment have found out that a relatively large generator is needed for causing problems for the utilized overcurrent IED when its settings were done appropriately. The simulations, however, revealed that some changes to the settings may be necessary for correct operation of the IEDs when new DG units are connected. It is thus very important that the engineers responsible for network protection planning in network companies are aware of the effects of DG. There may, nevertheless, be some more difficult situations in other networks where more sophisticated protection schemes like distance or differential protection are needed.

4.2.1. Directional overcurrent protection scheme

Directional overcurrent protection scheme functions as a normal overcurrent relay except that it is also able to detect the direction of the fault current. In other words, directional overcurrent relays trip only if the current magnitude exceeds the trip margin and, additionally, the direction of the fault current equals to the setting direction. [Kum 06b] The operation time of this protection scheme can either be based on constant or inverse time tripping. The tripping time is proportional to the current magnitude when inverse time mode is used. [ABB 00] Because of the ability to determine the direction of the fault, directional overcurrent protection could be used for tackling the sympathetic tripping (= selectivity) problems caused by DG. [Kum 06b] There are, nevertheless, some more complex cases in meshed networks where directional overcurrent protection may be inadequate and which, therefore, necessitate the use of distance or differential protection. Directional overcurrent protection schemes also have the disadvantage of changing their coordination characteristics as the network or generation conditions change. [And 99]

The detection of the fault current direction can be based on many methods. One traditionally used method is based on comparing the fault current of each phase separately to the opposite principal voltage. For example, the current of the first phase I1 will be compared with the principal voltage phasor U23. The relay will launch a trip signal if any of the phase currents exceeds the trip margin and is toward the forward direction (or to the opposite direction depending on the settings). It is, of course, necessary for this sort of operation logic that the relay stores the voltage phasors in its memory so that they are available also during three phase faults. Other methods for determining the current direction also exist and such are presented in [ABB 00]. [ABB 00]

Interlocking can be used as a means to speed up the operation times of the relays. When a fault occurs, the nearest relay(s) (one or multiple relays depending whether the network is radial or meshed) to the fault will trip and give locking signals to sequential relays that are not supposed to trip. This way the fault clearance time can be shortened compared to a situation where interlocking is not used. Interlocking is best suited for radial networks that have significant differences between the load- and short circuit currents. This makes it easy to configure the current settings for the interlocking current level. It is, nevertheless, possible to apply interlocking to meshed networks as well provided that directional overcurrent or distance protection schemes are used. When interlocking is used, attention will have to be paid to the fact that protection zones do not cover each other and, therefore, time selective protection scheme will always have to be used as back up protection. [ABB 00]

4.2.2. Distance protection scheme

Distance protection scheme is capable of determining the distance between the measurement point and the fault point. The use of this protection scheme often enables more rapid operation times and easier coordination compared to directional over current protection schemes in meshed networks. The determination of the distance is based on calculating the impedance between the fault point and the measurement point of the IED. The impedance is calculated by dividing the current phasor by the voltage phasor which, of course, necessitates both current and voltage measurements. The actual distance is then achieved by comparing the impedance calculated from the measurements to the known impedance (known provided that the line length and electrical parameters are known) of the protected line.

The idea of this protection scheme is to create protection zones (generally from 2-3 in distribution networks [Fri 01]) which have their respective operation times. The first zone is usually set to cover only some 80 to 90 percent of the protected line in order to make sure the IED will not trip on faults that occur behind the next circuit breaker. The protection on zone one can then be set to trip instantaneously. [And 99] The second zone, on the other hand, will be set to extend behind the next sectionalizing circuit breaker [Chi 04] or busbar [Fri 01] thus providing back up protection for the next circuit breaker. The downside of this is that there will have to be an appropriate delay in the second zone which will lead to delayed fault clearing in case a fault at the end of the protected line. This downside can, however, be overcome with an end to end communication channel arrangement which is widely used in transmission networks. In this case, a communication channel which can be based on many techniques, such as power line carrier, optical fibres, pilot wires etc., is established between the sequential distance IED's. In the occurrence of a fault at either end of the line, the relay that "sees" the fault on its first zone will trip without a delay and signal the relay at the other end that "sees" the fault on its second zone, to do likewise. [Zie 06] The third zone, which is often not used in distribution networks, might be set to trip with a delay which is just below the thermal breaking point of the equipment in the zone. [Fri 01]

DG units that are located between a distance relay and a fault might cause a phenomenon called protection blinding which, in other words, means that the relay will not trip when it should due to the fault current contribution of the DG units. This is because the fault current is divided between the DG units and the feed point which will lead to reduced current magnitude at the measurement point of the feeder protection relay. The reduced current will in turn lead to increased voltage magnitude at the beginning of the feeder. The impedance seen by the relay will thereby be higher which, in other words, means that the relay considers the fault to be further away than it actually is. [Adi 08b, Mäk 05]

Distance relays have many benefits. They, unlike the directional overcurrent relays, are unaffected by the changes in network or generation conditions. Distance protection scheme is also more economical compared differential protection scheme, which requires two measurement points and relays as well as appropriate communication between the two points. [And 99] It is also beneficial that distance protection relays enable rapid fault clearing while maintaining the selectivity and provide a back up protection for some parts of the network because of their multiple protection zone arrangements. Distance relays, nevertheless, do also have some disadvantages such as their inability to detect earth faults in isolated neutral and impedance earthed systems, which for example, are used in Finnish distribution networks. Another disadvantage is that distance relays do not suit well for protecting lines less than 10 km long and that their operability is deficient in high resistance earth faults as well as in conductor phase failures. [Mör 92]

4.2.3. Differential protection scheme

Configuring conventional overcurrent and distance protection relays for protecting short lines, particularly the ones close to longer lines, may sometimes be problematic. In order to ensure selectivity, these protection schemes may have to be adjusted to trip with appropriate delays. This is, however, harmful because the delayed fault clearance causes stresses to the equipment in the faulted network. [For 04] Such problems with delayed operation could be solved by utilizing differential protection because it provides absolutely selective operation, i.e., it detects faults only within its area of protection. Differential protection relays can, therefore, be set to trip very rapidly and with high sensitivity. [ABB 00, And 99]

Differential protection is based on measuring the currents from both sides of the protected element which can be a component or a line. During normal operation the difference between the currents measured before and after the element is zero. If a fault should occur on the protected area a difference in the current amplitudes or phase angles would be born. The protective relay is triggered if the difference between the measured currents or amplitudes is greater than the triggering setting value. In order to avoid measurement errors caused by the current transformers, the triggering value is proportional to the measured current. In other words, as the measured current increases, so does the required difference between the currents needed for the triggering. Since this protection scheme is based on comparing the measurements of each end to each other, appropriate communication arrangement is, of course, necessary. Usually the communication channel between the IED's is also supervised. [And 99]

Meshed and ring type networks often require unit protection schemes which, however, can as well be applied in radial networks including DG. [ABB 08c] Unit protection stands for a concept where protected area consist of everything inside the measurement points (two or more). Such an arrangement could, for example, consist of three IED's based on differential protection with respective communication arrangements between each other. The IED's would then be measuring all the currents entering the protected zone and all the currents exiting the zone. During normal operation there would, of course, be no difference between the currents, where as, during a fault inside the protected zone the case would be the opposite. [And 99] The idea of unit protection is presented in the Figure 4.2 where the protected are is marked with dashed line.

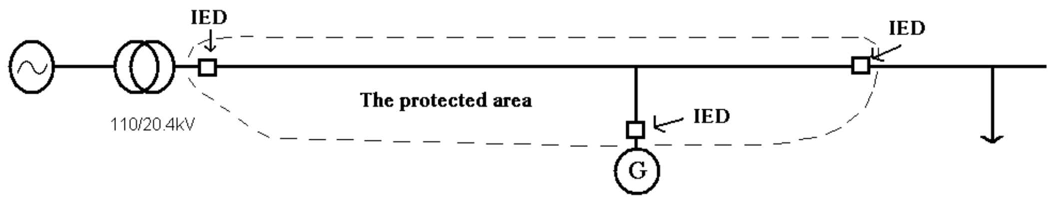


Figure 4.2. The idea of unit protection

4.2.4. LOM protection

Probably the trickiest of the protection problems is, however, related to the LOM protection of DG units. LOM protection makes sure that no unintentional power islands are formed in distribution networks. Combined voltage and frequency protection is probably the most utilized LOM protection scheme because it is applicable to all types of generation units. The problem of this, and also most of the LOM protection schemes, is the fact that it cannot detect islanding if production and consumption in the islanded zone match closely enough with each other. The blind area in which LOM protection fails to detect islanding is called the non-detection zone (NDZ).

Unintended islanding is not tolerated for a number of reasons. Probably the most serious reason for this is that unintended islanding pose a security risk for the DNO personnel by re-energizing the lines that are expected to be de-energized. The islanding situations may also cause auto-reclosing failures by back feeding the lines and thereby maintaining the arc that would otherwise be extinguished before the autoreclosure. The DG unit itself as well as the circuit breaker performing the autoreclosure might be damaged as a result of an out-of-phase reclosing. There is also a risk that the customer devices may be damaged due to the poor power quality in an island zone. Because of these reasons it is obligatory that appropriate loss-of-mains (LOM) protection is applied in the DG unit interconnection points. [Brü 05] Intended islanding, which can have a tremendously positive effect on the reliability of the supply, is a whole another story and it will be discussed later in the chapter 4.4.5.

The LOM protection settings have traditionally been set quite tight in order to reliably detect islanding. The tight relay settings, however, have the disadvantage that DG units will then be easily tripped off when a fault elsewhere in the network causes the voltage or frequency to drop to some degree. This, in turn, poses a risk to system stability since the voltage and frequency will drop even more after the tripping of the DG units. In order to take part in the system services, the protection of the DG units will have to be loosened and the units must have a FRT capability, i.e. they must withstand voltage and frequency fluctuations caused by a fault elsewhere in the network. [Ple 03]

The present LOM protection schemes are able to detect islanding whenever the power generated by the DG units in the island zone does not match closely enough with the loads in the possible island zone. There is, nevertheless, a chance that generation matches with loads, which is not possible to detect with the present LOM schemes. This is called the non-detection-zone. [Brü 05] The functioning of frequency and voltage protection schemes was first studied after which also the rate of change in frequency (ROCOF) protection scheme was included. As expected, the blinding of LOM protection was found to be a real problem. Voltage and frequency protection based LOM protection especially suffers from a large NDZ. ROCOF was found to have a considerably smaller NDZ. The size of the NDZs can, of course, be reduced by applying stricter settings but this, on the other hand, can cause nuisance tripping. Care must, therefore, be taken when choosing appropriate settings for various LOM protection schemes.

4.2.5. Interaction of FRT and LOM

Wind power capacity has been steadily growing in the recent years. In areas, where the share of wind power has already reached significant levels, the local TSOs have understood that wind power cannot be allowed to be operated completely independently from the rest of the power system. Because of this, FRT requirements specifying the requirements on wind generators during voltage dips have been issued by these TSOs. These requirements give the voltage dip depth and form which the generation units need to be able to ride through without losing their stability. In addition to staying connected during the fault, modern wind turbines should be able to support the grid voltage during the voltage dip by injecting reactive power. At the moment, these requirements are mostly made for wind farms connected to higher voltage levels but it is foreseeable that similar kinds of requirements will eventually diffuse to distribution network connected DG units as well. If this will be the case, then attention has to be paid to the coordination between LOM protection settings and FRT requirements. It is of no help at all if a DG unit has FRT capability but the LOM protection has been set so tight that it does not allow the DG unit to ride through the fault. DG unit protection should be slow enough to fulfil the FRT capability requirement, and at the same time it should be fast enough to disconnect DG units on faulty feeder. Fulfilling the FRT requirements by loosening the protection settings of passive LOM extends the size of NDZ. The realization of the FRT capability thus increases the risk of unintended islanding not only because of the necessity of loosening the LOM protection settings but also because a DG unit that has FRT capability is more capable of maintaining power islands. In this sense, LOM protection settings are a compromise of some kind between enabling FRT and avoiding unintended islanding [Mäk 09].

4.2.6. Interaction of autoreclosing and LOM

The functioning of fast autoreclosing (AR) on feeders including DG is often mentioned as one of the main concerns related to DG. AR has a significant importance for the reliability of electricity supply since the majority of faults on overhead distribution lines are temporary and AR helps restoring electricity supply. The situation is, however, becoming more difficult as DG is connected along distribution lines. This stems from the fact that DG can sustain the voltages during the open time of the circuit breaker performing the AR thus causing the AR to fail. It is, therefore, crucial that all DG units on the tripped feeder are disconnected before the reclosing attempt. The disconnection is meant to be taken care by the LOM protection.

RTDS simulations with feeder and LOM protection relays where performed to study how different kinds of protection settings influence the successfulness of AR. The results indicated that the success rate of AR is strongly dependent on the chosen protection settings and from the prevailing imbalance between production and consumption [Rai 10].

The simulations indicated that success of AR can be reached with relatively simple LOM protection provided that strict LOM relay settings are used. Strict LOM relay settings, however, have the disadvantage that they make the protected DG unit prone to nuisance tripping which is unwanted both from the network and the DG unit point of view. Nuisance tripping of DG can also be risky for the system stability in certain areas where DG penetration is high. The simulation results also indicated that under voltage (UV) function of LOM protection has a very significant role in ensuring a high success rate of ARs. The utilization of strict UV thresholds may, however, not be allowed in the future if DG units are needed to contribute to system stability – that is, if the FRT requirements are diffusing to MV level as well. The utilization of strict UV limits is clearly conflicting with the FRT requirements which demand that generation units are able to ride trough deep voltage dips without losing their stability.

Another option for improving the success rate of ARs is prolongation of AR open times. This option is unfortunately also unwanted since this measure has a degrading effect on power quality. The problems with AR and unintentional islanding could, of course, be tackled by equipping all DG units with a LOM protection technology that is not prone to the NDZ problem. Communication based LOM protection methods are one of such solutions but they generally require some additional capital compared to passive and active detection methods.

4.2.7. Communication between feeder and generator protection

The paper [Rin 08] suggests that NDZ problem could be tackled if fast and reliable communication between the IED's on the feeder and the IED's protecting the DG units were established. In such a case, the IED commanding the feeder circuit breaker open could simultaneously order the IED's protecting the DG units to trip and thus avoiding the possible islanding situation. [Rin 08] The communication uses both standard IEC 61850 GOOSE messages and user definable signals using Binary Signal Transfer (BST) that RED 615 IED offers. A high bandwidth optical link transfers information between the line ends in digital format. The total signal transfer time delay has been below 30 ms using two REF 615 and two RED 615 IEDs (BST between 2 RED 615 IEDs < 5 ms). Two basic advantages of fast communication based LOM protection scheme are:

- Fast tripping of generator when the fault is in the generator feeder or on the substation.
- Securing FRT when the fault is on the other feeders.

Establishing a reliable LOM protection with the help communication between the IED's is illustrated in Figure 4.3. The communication between IED's on the same substation is accomplished using the fast and reliable GOOSE (General Object Oriented Substation Event) messaging provided by the IEC

61850 standard. The communication between sequential IED's (for example the two RED615 IED's in the Figure 4.3), on the other hand, is established via the so called Binary Signal Transfer (BST). IED's containing BST ability have 8 bi-directional bits reserved for user defined communication purposes. A fault in location Fault 1 causes a voltage dip. IED of CB1 trips and sends block as a GOOSE message to IED of CB2. IED of CB2 sends the message via BST to IED of CB3. IED of CB3 sends the block message to LOM IED as a GOOSE message. The fast communication and block message improves the selectivity of the protection system without sacrificing the FRT requirement of the DG unit because the DG unit will not be disconnected due to voltage dip. Also a local LOM protection relay may be utilized as a backup relay for communication based protection scheme. In case of Fault 2 overcurrent protection in IED of CB2 trips and sends a trip command using BST to IED of CB3. This IED sends a trip message to the LOM IED. In this way the DG unit will be disconnected without unnecessary delay. DG unit may be disconnected similarly when e.g. connection to supply network from the substation has been lost or fault is located at substation busbar. This way the islanding would be reliably avoided and, moreover, this whole signal transfer process would take less than 30ms time. [Rin 08]

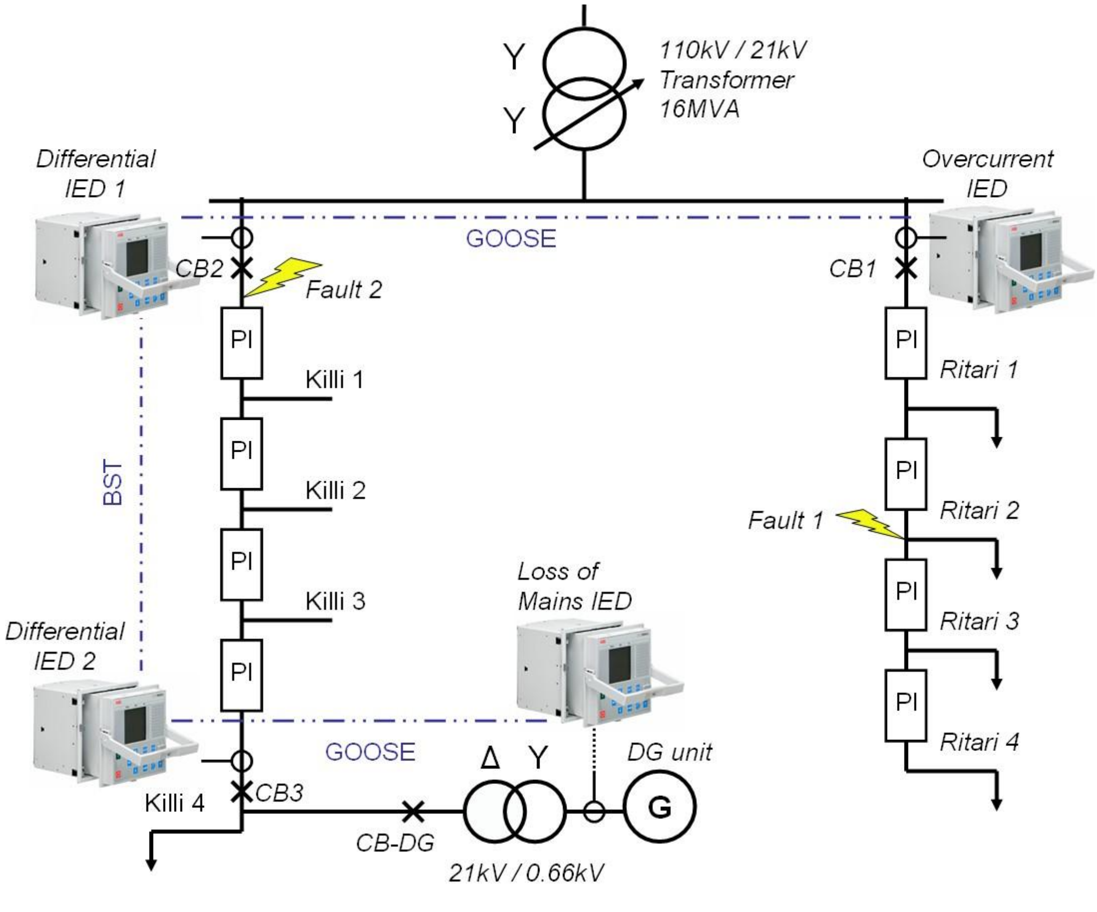


Figure 4.3. Communication arrangement between feeder and DG unit protection [Rin 08]

4.3. AUTOMATIC CONTROL SYSTEM (DECENTRALISED)

4.3.1. Frequency control

Different types of power production all have their own technical and economical characteristics, which govern the way they are used. The amount generation dispatched each hour is based on load predictions that are made one day in advance for every hour of the following day. The hourly load predictions are relatively accurate but there will usually still be some unbalances between the production and consumption. In order to balance these deviations, generators are dispatched more precisely for every 15 minute period one hour in advance. These power deliveries are handled in special regulating market. Changes in the load occurring faster than in 15 minute periods, however, are not predicted at all. The balancing of these deviations, which should be relatively small, is left for the frequency control. [Ple 03]

Frequency control consists of two components, namely primary and secondary control. The power plants participating in the primary control all have to be equipped with turbine governors with automatic frequency controllers. These controllers are fast and their gain is selected in such a way that the power required is divided between the participating generators proportionally to their capacities. [Ple 03] If a deviation in the power balance of the system should take place, the rotational masses of all the generators will either absorb or release kinetic energy, which results in a change in the system frequency. This is called the inertial response. If the frequency deviation is large enough, the primary frequency control will be activated. [Mor 06] After the primary control has compensated this power unbalance, there will still be a small deviation in the system frequency. If this deviation is large enough, secondary control reserves are activated which will bring the frequency back closer to its nominal value, and thereby free the activated primary reserves for prospective needs. In the NORDEL power system (includes the Finnish, Swedish, Norwegian and the eastern part of the Danish power system [Nor 08]) primary control is automated whereas secondary control is manual. [Ple 03]

There will also have to be additional control reserve for contingencies where a generation unit or an interconnection is suddenly lost. The size of the required control reserves for disturbances is determined by the largest generation unit or the interconnection with the largest imported power flow. [Ple 03] Load control, which will be presented later in this report, has very favourable characteristics for being used as this kind of contingency reserve. By using load control as reserve capacity the generators allocated for reserve capacity could be liberated from this task to be used for power production. [Kir 99]

The protection of the DG units is generally adjusted to trip as soon as voltage or frequency deviates from normal operation values. These kind of tight protection settings guarantee good protection for the DG unit and thus please their owners. Sensitive protection settings of DG also please the DNO because they guarantee good protection for other network equipment and ensure that problems related to unintended islanding are not to occur. This sort of protection settings have also been tolerated by the system operator as long as the penetration of DG has been low. The amount of DG is, however, now rapidly growing and it can be anticipated that they are likely to replace some of the conventional generation. This has made the operators realize that they might not be able to maintain the power balance if single contingencies, such as a single short-circuit or a loss of a single generating unit will cause vast amounts of tripping. Many system operators, such as the Swedish Svenska Kraftnät and the Danish Energinet.dk, are now making new more demanding operation requirements for wind farms, and it is anticipated that similar requirements shall also be made for DG units in the future. [Ple 03]

Wind power is problematic in the sense that its production is difficult to predict and that the production does not correlate with the demand. This leads to the fact that additional reserve capacity is needed if the proportion of wind power is high. If wind power is to replace some conventional power plants it may be necessary that wind power has to become a part of the control reserve. In order to be able to control the frequency up and down, wind power must be set to operate on lower than full capacity. This, of course, is a waste of energy and thus increases the cost of the energy produced by wind power. The use of energy storages with adequate capacity, as for instance pumped hydro energy storage and large scale storage of hydrogen combined with fuel cells, could solve this problem. Present hydrogen storages combined with fuel cells unfortunately have the disadvantage that the efficiency of their charge-discharge cycle is less than 50 percent. [Ple 03]

Many DG units are connected to the network through power electronic converters. These sorts of units are separated from the system frequency and are, therefore, allowed to operate on whatever speed is optimal for them as, for example, the variable speed wind turbines and the micro turbines do. Some DG units, like fuel cells or photovoltaic, have no rotational parts at all. Units with a power electronic converter connection, therefore, require special arrangements in order that they could participate to frequency control. Such arrangements are presented in [Mor 06], where the frequency control capabilities of different kinds of DG units are also examined. Wind turbines cannot participate in the primary frequency control in the classical sense, unless they are operated on lower than full output power as explained earlier, but they are capable of rapidly releasing their rotational energy to the system and thus contributing to the frequency control for a short period. Fuel cells, on the contrary, are not capable of rapid power output changes, whereas, it can sustain slow power output changes. In that sense, these two are of somewhat complementary. Micro turbines, which are basically small gas turbines, are, of course, capable of primary frequency control as long as they are not operating at their full power. [Mor 06] Small-scale hydro-generation is well suitable for frequency control provided that the unit includes a reservoir of a considerable capacity. Without considerable storage capacity the output of hydro-generation unit is dependent on the river flow and is thus likely to undergo large variations. [Jen 00] Small scale CHP unit are usually set follow the heat demand and the electricity is thus only a by-product that is being produced in proportion to the heat production. The produced heat and electricity in a CHP unit including a heat accumulator can, however, be decoupled to some extent depending on the capacity of the accumulator. [Ple 03] All in all, there should be a mixture of different kinds of DG units in order that the DG could obtain a good contribution to the primary frequency control. [Mor 06]

4.3.2. Active voltage control

Some voltage control methods based on local measurements are already widely used in distribution networks. These kinds of solutions were discussed in the ADINE report D10 “Demonstration report on the use of existing voltage control methods” [Adi 08c]. It may, however, be that the existing voltage control methods will become inadequate if DG penetration reaches considerable levels. Should this be the case, active voltage control offers a wide range of new solutions.

Active voltage control can be divided into two hierarchical levels, namely the local and the coordinated voltage control. The local control is based on local measurements and controllers which regulate the voltages at their operating points by controlling active resources such as DG units and reactive power compensators. The voltages can also be regulated by controlling loads and, in extreme cases, by curtailing the DG unit production. Coordinated voltage control, on the other hand, makes its control decisions based on measurement data concerning the whole network that is under its supervision. Coordinated control may regulate the network voltages solely by controlling the on load tap changer (OLTC) situated at the substation or by the combination of all the resources capable of voltage control. Communication channels between the network nodes are, of course, needed since this sort of control requires information about the state of the whole system. [Rep 05, Kul 07]

This chapter first presents four local voltage control strategies. These are the reactive power control of the DG units, load control and finally production curtailment. After these, also coordinated voltage control method will be presented

4.3.3. Reactive power control of the DG units

Local voltage control is a fairly attractive solution since many of the DG units are already capable of continuous power factor or voltage level control. This type of control is based on local measurements and controllers, which try to maintain the voltage at the unit terminals within permissible limits. [Rep 05] The local controllers can, however, also change their control mode back to normal power factor control at times when the voltages at the DG unit connection point are within permissible limits [Kul 07].

The idea is to control the reactive power production/consumption of a DG unit or a reactive power compensator which, in turn, affects the voltage at the connection point. The DG connection point voltage rise problem can, for example, be mitigated by consuming reactive power in the DG unit. Reactive power control in the DG units can be achieved by power factor correlation in case of induction machines, excitation system in synchronous machines and reactive power in applications connected through frequency converters. This control possibility is, nevertheless, generally not being used at present because of the restrictive connection contracts that only allow a rather narrow range for the free-of-charge power factor. [Rep 05]

The DNO's should, however, bear in mind that relatively large reactive power flows might be needed to mitigate the local voltage rise caused by real power generation since distribution networks tend to have low X/R ratios. Increased reactive power flows, in turn, require higher thermal capacity, cause bigger network losses, increase the burden on VAr sources and might interfere with the power factor sensitive tap changer schemes. [Sco 02] The DG unit reactive power control is, nevertheless, a potential alternative to network reinforcements, especially if the voltage rise problems are occasional. [Rep 05]

4.3.4. Voltage control in MV network

The voltage level management of radial distribution system is currently controlled by the AVR of OLTC of primary transformer. OLTC adjust the voltage ratio of transformer without interruption using tapping steps. The AVR of OLTC is operated either in a constant voltage or in a line drop compensation mode. [Adi 08c]

The voltage control of DG, STATCOM, in-line voltage regulator, etc. is a mature technology which could easily be applied in distribution networks. The common connection requirement of a DG unit is however the unity (or constant e.g. >= 0.95) power factor at the point of common coupling. The origin of this requirement comes from the aim to minimize reactive power flow in distribution network. The reactive power flow reserves the part of network capacity for a non-productive purpose. However the thermal capacity of network is seldom the constraint in weak distribution networks but the voltage drop is the typical constraint for rural distribution networks. When the rural distribution network includes DG the voltage rise becomes a severe problem. The traditional worst case planning principle together with voltage problems in rural networks creates a barrier for DG connection to existing network. The portion of reinforcement of distribution feeder supplying DG may be avoided by allowing DG units to participate on voltage control. The voltages in the network can be kept within limits by using various active resources capable for consuming reactive power. Most DG units are already capable of controlling their power factor and thus consuming reactive power. This is a fairly simple but yet effective way to increase the amount of allowable DG capacity but it necessitates appropriate ancillary service contracts between the DNO and the owner of the generation unit in question.

The traditional voltage control method of a synchronous generator is based on droop characteristics. The droop is a slope between the voltage and the reactive power produced by the generator (blue slope in Figure 4.4). The droop method in distribution network is not as effective as in transmission network due to low X/R ratio of distribution network. However the droop characteristic allows the parallel operation of generation units using decentralized control method without interference and a fast response in case of local voltage change. The same control method is applicable also in DG units equipped with power electronic converter and in STATCOM.

Another version of decentralised voltage control is the voltage constrained reactive power control method (red curve in Figure 4.4). The idea is to maintain constant power factor (e.g. unity power factor) as long as possible in order to avoid unnecessary reactive power flow but maintain network voltage level within specified limits by utilizing local reactive power support. The controller is based on cascade control of AVR, power factor regulator and voltage constrained method. The response of this controller is slow in order to allow the OLTC respond first.

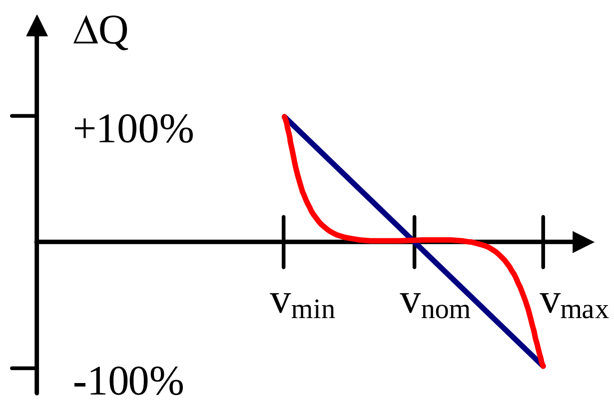


Figure 4.4. The droop characteristic (blue slope) and voltage constrained reactive power control method (red curve) of DG unit voltage controller.

Distribution network voltages are also controlled with reactive power compensators, in-line transformers and tapped distribution transformers [Lak 95]. Shunt capacitors and reactors, which are used only to minimize the reactive power transfer through the substation transformer or the main grid connection point, may continue to operate on decentralized way because compensators are not participating on distribution network voltage level management. However the active voltage control along the distribution network may increase the need of reactive power capacity at primary substation in order to keep reactive power flow between transmission and distribution network within allowed (free of charge) limits.

Smaller capacitor banks and reactors are used along the MV feeders and in LV networks to control the distribution network voltage. If the switching of compensator is based on time of day, then the intermittent DG production may cause conflicts in network voltage level management. Automatic relays can be used to switch the capacitors on and off depending on the load or the connection point voltage. The AVR or power factor controller of compensation device might also be implemented as a part of co ordinated voltage control method.

The in line transformer is an autotransformer having nominal turn ratio 1:1. Those are mainly used at very long distribution feeders to compensate voltage drop at the end of feeder where this cannot be alleviated by boosting the voltage at primary substation to exceed the limits on nearby customer's connection point. The in line transformer may also be used to compensate voltage rise caused by DG unit in weak distribution networks. The voltage level management may be improved with the in-line transformer equipped with tap changer and AVR when the voltage variation is remarkable e.g. due to intermittent DG production. The investment cost of in line transformer is typically less expensive than feeder reinforcement of relatively long distribution line. The co ordination of cascade tap changers at primary substation and along the feeder requires special consideration [Lar 00].

Distribution transformers often have tappings which can be selected off-load. Since the tap changes must be done manually and off-load, the distribution transformer tappings are rarely changed [Lak 95]. The appropriate tapping for a distribution transformer is not determined only by the maximum voltage drop on MV and LV networks but also by the maximum voltage rise on these networks when there is a DG unit in MV network. If the tapping is selected based on maximum voltage drop there exists a risk of over voltage in LV network during voltage rise in MV network. If appropriate tapping could not be found the reinforcement of LV network is needed in order to meet power quality requirements in all connection points.

4.3.5. Voltage control in LV network

The active power from DG units affects voltage, which is one of the factors limiting the amount of DG. While reactive output of large power plants is used to control voltage, it is normally required to be zero for DG units. The very small rated power of DG units and the resistive character of low voltage cables also strongly limit the impact of reactive power on voltage at LV level. A DG unit at LV level can therefore hardly control voltage.

But connecting the unit through a series inductance as depicted in Figure 4.5 gives a connection point at the microturbine terminals where voltage can be regulated. This provides improved voltage quality for loads of limited rating. The solution effectively rejects both voltage dips caused by switching of local loads and disturbances originating in the feeding network. Network strength and impedance character are not critical. The resulting scheme has similarities with how selected loads are protected from power interruptions with uninterruptible power supply. It also resembles island operation but with the network connection weakened instead of removed.

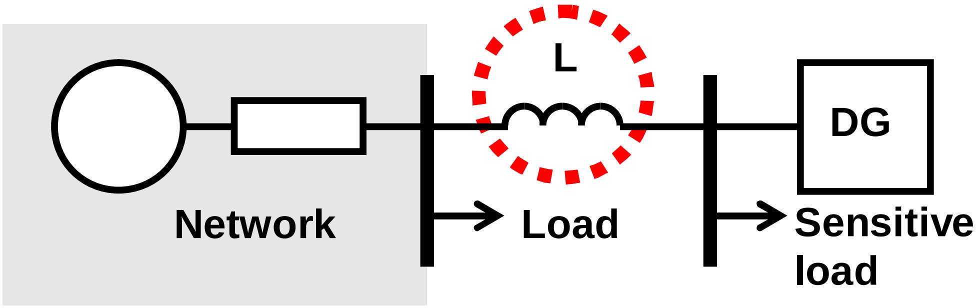


Figure 4.5. Connection to LV network through decoupling inductance.

A microturbine rated 5 kWe has been equipped for voltage control. The commercial single-phase power electronic converter is replaced by a three-phase prototype connected to the network through 7 mH inductances. The converter is controlled using a standard vector control scheme with a voltage controller setpoint equal to nominal network voltage. The simulations indicate that the control scheme eliminates steady state voltage deviations. Also at transients voltage deviations are efficiently reduced. More details are found in [Sul 10]. Starting of a 0,37 kW motor on the weak side of the LV cable causes a clear voltage dip. As shown in Figure 4.6 this is well suppressed at the protected point, which indicates that the control scheme is both feasible and efficient.

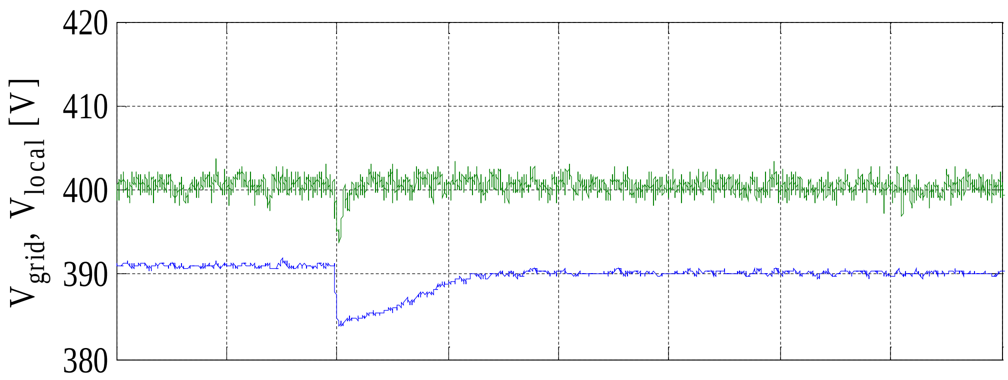


Figure 4.6. Measured reponse to direct starting of 0,37 kW three-phase asynchronous motor.

4.3.6. Power electronic compensation to improve power quality

Voltage rise, power quality and power system stability issues can sometimes restrict the penetration of DG resources. Devices such as, distribution level FACTS (Flexible AC Transmission System), SVC and STATCOM can be used as a means to tackle such restrictions. A typical SVC is based on a combination of a thyristor controlled reactor and a harmonic filter. It can, for example, be used to give reactive power support to wind farms in steady state as well as in transient disturbance conditions as presented in [Grü 08]. The performance of STATCOM is similar to SVC but it has some advantages compared to SVC such as compactness, faster control and current injection independent from the voltage. [Mai 07, Eri 00] STATCOM is capable of filtering flicker, harmonics and compensating reactive power and it may also be used for mitigating voltage dips and for controlling the voltage level of the distribution network. [Adi 08a] STATCOM's make use of voltage source converters, which acts as voltage source that is capable of controlling the voltage phase, frequency and magnitude at its interconnection point. A voltage source converter configuration consists of a capacitor bank connected through a converter bridge which contains four IGBT (Insulated Gate Bipolar Transistor) valves and two diode valves in each of its legs.

An increasing number of electrical equipment with power electronic components or non-linear voltage-current characteristics is connected to the distribution network. Due to their distorted or unbalanced currents, the power quality decreases steadily in the distribution network. The poor quality of supply voltage is experienced by all electrical equipment connected to the same network, leading to higher thermal loading and/or higher audible noise of motors, transformers, capacitors, switch-gear and cabling. Voltage sags and dips can cause loss of production in automated processes. Computer or data processing systems can be forced to crash. Sensitive electronic protection, control and ripple control systems are not likely to operate properly with poor supply voltage quality. Unwanted current harmonics, flowing across the distribution network, can cause additional losses and heating in transformers and Electromagnetic Interference (EMI). It can be concluded that a poor power quality can cause loss of production and damage of equipment.

Ensuring adequate power quality in distribution networks there are commonly applied technical limiting values in network planning for different power quality characteristics. Standard EN 50160 "Voltage characteristics of electricity supplied by public distribution systems" [Eur 00] gives the limits or values within the voltage characteristics of connection point that a customer can expect. It gives also a guideline what kind of voltage characteristics variations consumers and DG units should tolerate in the connection point.

Because the equipments affect on power quality and dimensioning of distribution network, there are also applied limiting values for grid connected equipments in connection contract, standards and distribution network planning recommendations. Equipments interact with each other and with distribution network. Therefore the characteristics of both the equipment and the network are important for power quality. The penetration of DG may improve (e.g. increase network short circuit capacity or reduce voltage drop on feeder) or decrease (e.g. increase the amplitude and the number of voltage variations or increase voltage flicker) the level of power quality dependent on case-specific network conditions and characteristics of DG units. An example of electromagnetic compatibility standard for a DG unit is IEC 61400-21 "Measurement and assessment of power quality characteristics of grid connected wind turbines" [Iec a] which defines the power quality characteristics of a wind turbine and the assessment of these characteristics on electricity network.

If power quality at connection point is not adequate or it includes very sensitive loads there are numerous ways to resolve those challenges. One applicable technical solution is the utilization of STATCOM for filtering harmonics, eliminating flicker, balancing load and compensating reactive power caused by wind farm, arc furnace, etc. It has also proven to be able to mitigate voltage dips by injecting reactive power in such a way that helps to maintain the voltage at wind farm connection point during balanced and unbalanced faults in the network and thus supporting wind farm's FRT capability [Mai 07]. There are some installations where STATCOM is utilized to ensure grid code compliance. STATCOM may also provide ancillary services for a DNO e.g. reactive power support or voltage control. Utility STATCOM may also be applied for damping oscillations and improving transient stability in the power system.

For these applications both large steady-state operating range and fast transient response are important. The advantage of a STATCOM over the conventional SVC is the extensive operative range. For comparison, the voltage-current characteristics of (a) SVC and (b) STATCOM are shown in Figure 4.7. The maximum capacitive current of the SVC is limited by the reactance of fixed capacitor when the system voltage decreases. As the result, the voltage support capacity of the SVC impairs with the decreasing system voltage. On the contrary, the STATCOM is able to provide full capacitive current independently of the system voltage, almost down to zero. A further advantage is the increased transient rating in capacitive operation region, which is in the SVC again limited by the fixed capacitor value. As the result, a STATCOM provides a superior capability for compensating dynamic power system disturbances.

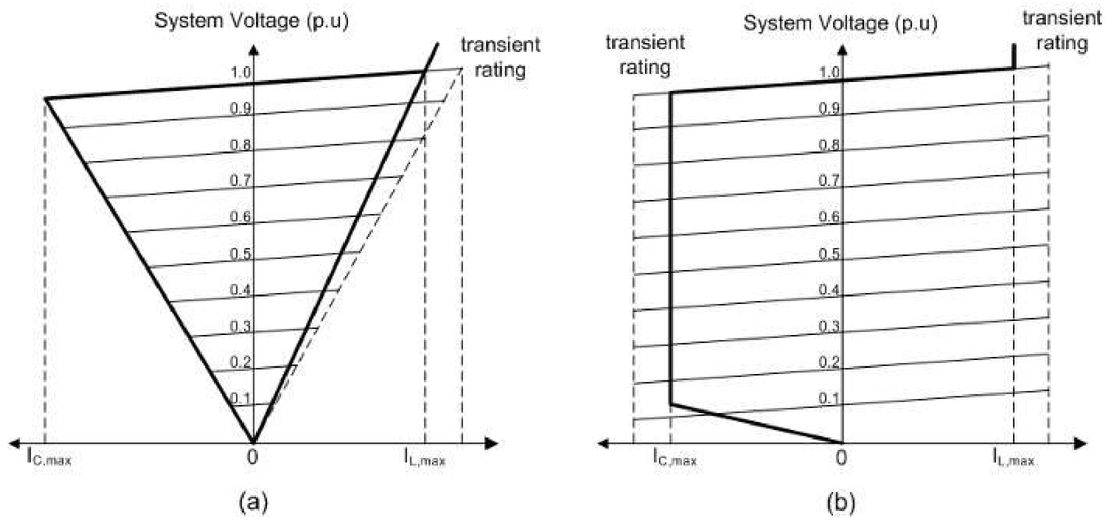


Figure 4.7. Voltage-current characteristics of (a) SVC and (b) STATCOM.

The voltage source converter technology with high switching frequency thus makes the STATCOM superior to an SVC in both the transient and the steady state operating regime. The three-level converter topology with IGBT-s further improves the performance regarding harmonics.

The capacity of STATCOM might be reserved for only one purpose or it might be utilized for a combination of purposes. The latter one is an interesting option when the disturbing power quality issues might change over time. The STATCOM controller has a power quality priority list for the utilization of its capacity. The idea is to utilize STATCOM capacity fully for the first thing in the list. If there is free capacity available after adequate control margin, then the capacity is utilized for the second thing in the list. However the control has priority for the first thing which means that there are made more compromises with the second control issue than with the first one. For example if the highest priority of STATCOM at wind farm application is set for the flicker elimination, there might be conditions when the amount of flicker is not severe in which case the capacity may also be utilized for e.g. harmonic filtering. The adaptability of STATCOM for time varying power quality issues is not however easy. For example the support of wind farm FRT capability is quite seldom needed, but when it is needed this must definitely have the highest priority in the list. The real time resetting of priority list based on local measurements might be a possible solution to adapt STATCOM for different kind of circumstances. Further adaptability for the utilization of STATCOM would be achieved if the power quality priority list is dependent on local operational conditions like the amount of disturbing power demand or production and the characteristics of load demand or production (e.g. how gusty wind is). STATCOM controller might also collect measurement information about local power quality issues in order to adapt the power quality priority list based on operational history.

4.3.7. Load control

The ability to control customer loads provides another promising alternative for maintaining the voltage and frequency within permissible limits. Load control is based on switching controllable loads on (or off) to fill demand minima's (maximum's) during periods when the DG power generation is high (low). Voltage fluctuations originating from, for instance, wind generation can also be tracked and tackled by fast dynamic load switching. This, however, requires better control and communication systems but will be considerably more energy efficient compared to slower switching strategies. [Sco 02] The AMI, which in many countries are now being installed in increasing numbers, provide a very promising alternative as a communication medium for load control [Jär 07]. Loads that are capable of storing energy, such as thermal, cooling, pumping, etc. loads, are the most suitable ones for load control. This stems from the fact that turning such loads on or off basically causes no inconvenience to the customers since the energy can be used stored for later use. [Sco 02]

The need for load control is infrequent because of the occasional nature of voltage rise problems. This leads to the fact that the payback time for the assets needed for load control devices will be relatively long. In order to improve the economical attractiveness of load control, the other possibilities provided by load control should also be harnessed. The other functionalities include, for example, peak shaping, the possibility of taking advantage of the low electricity cost periods, avoiding line over currents and alleviating LV network under voltage problems. All in all, load control is a potential alternative for enabling larger amounts of DG to be interconnected, although the contracts may become of somewhat complicated as there are three parties, namely the generator, supplier and distributor, involved. [Sco 02]

Direct load control based on local frequency measurement may also act as a frequency reserve. Space heating and similar type of loads may be controlled in accordance with dynamic demand control principle in which the temperature settings of space heater thermostats are frequency dependent. The reaction of dynamic demand control to frequency problem causes a period of zero load demand which length is dependent on the heat insulation of the building, the outdoor temperature and the length of frequency problem. If the indoor temperature will reach a preset limit for minimum temperature, the heating will turn on again and it will continue a normal operation within the preset minimum temperature.

The simulation results indicate that the operation of dynamic demand control loads is most effective in rapid and severe disturbances. The dynamic demand control method switches off load the amount determined by the severity of the disturbance and guarantees a certain predetermined minimum room temperature. Dynamic demand control requires frequency dependence from the thermostat, a feature which the space heaters do not have today. Nevertheless, adding the feature to new equipment can be done with low costs. As the number of loads needed is large, special attention should be paid to the coordination of operation. The management of dynamic demand control setting values and the monitoring of reserve functioning could be communicated via AMI. Furthermore the amount of controllable load is dependent on uncontrollable factors like outdoor temperature in a case of space heating, which causes a need to have several types of controllable loads in a portfolio in order to guarantee same level of service around a year. Perhaps the most problematic issues are however to find out a proper financial incentive and to dispel suspicions among the ownes of the resources. [Rau 08]

4.3.8. Production curtailment

In extreme network conditions, which should only rarely occur, the production could be curtailed in order to prevent excessive voltage rise. The production curtailment terms could be agreed with the DG unit owner either in the interconnection contract or in an ancillary service contract. This method is fairly simple in hydro power and CHP plants, where the turbine set-value adjustments are easily carried out. CHP plants are, however, not quite as suitable as hydro power plants because the CHP operation is strongly governed by the heat demand. Some CHP plants have heat storages which make it possible to separate the heat and electric power production to some extent. The electric / heat power ratios are also usually adjustable but the plant efficiency tends to degrade if the ratio is reduced. [Rep 05]

The easiest way for wind power curtailment is to disconnect a proper amount of units when the permissible voltage level is exceeded. The unit disconnection can be based on voltage relays, which either have different upper voltage values or tripping delay times, installed to the unit connection points. Variable speed and pitch controlled wind power plants can be controlled continuously by a frequency converter or blade angle control and, therefore, they need not be disconnected from the network. [Rep 05]

4.4. AREA CONTROL LEVEL (CENTRALISED)

The area control level is used to co-ordinate the functioning of individual devices. This is done by sending new setting values through the Relay setting tool or SCADA system. The co-ordination of protection and control devices requires measurement data from distribution network in order to evaluate the performance of protection and control.

4.4.1. Co ordination of protection relay settings

The presence of DG will affect the fault currents flowing in the network. In the worst case fault currents measured by the relay are reduced so that fault detection is disturbed. On the other hand, the DG unit or even the whole DG feeder may become disconnected during a fault elsewhere in the network.

Protection planning studies in networks including DG is commonly carried out by using dynamic simulation software, which provides accurate results if the simulations are prepared with care. The planning procedure should, however, at least from the DNO's point of view, be efficient and yet accurate enough as the DG interconnection studies are becoming a routine operation. In order to accomplish this, new efficient calculation methods are needed to be included to the present planning tools. Such calculation methods and their applicability to NIS presently used are discussed in [Mäk 06a] and [Mäk 06b]. [Mäk 06a, Mäk 06b]

DNO is typically using dedicated planning tools for planning and maintaining their networks. In Nordic thinking these planning functions are highly integrated to NIS. These systems are typically based on steady-state calculations and rms values. As the present calculation has proved to be reliable and to offer suitable information for planning purposes, it has been assumed that basic calculation should not be modified. Typically DNOs want to use their daily used planning tools instead of running dynamic simulations or performing complex calculations. DG planning in daily-used planning tools would offer more efficiency to DNO's planning activities.

The core of the developed method is the protection planning procedure [Mäk 07], which performs the necessary studies automatically in the correct sequence. The process goes through network faults point by point and saves results for further analysis. This calculation is iterated with time steps. The fault calculation is repeated in time steps between which the generator values are modified. This enables more accurate studies on relay operation times. Wrong operation sequences can be found with suitable analysis. The time step approach enables also studying different generator types. As a result, the impact of new DG unit on system protection can be studied. Incorrect operation on certain fault locations is reported and modifications can be made according to the results. The developed planning method has been implemented in NIS during the ADINE project [Adi 10b].

Protection problems caused by a DG unit may be eliminated or alleviated for example by proper co ordination of protection settings. The co-ordinated protection planning function of NIS will analyze and plan protection settings for protection relays [Mäk 07]. Two of the key features of the method are a procedure for studying protection aspects in proper sequence, and a novel method for defining the protection requirements for a new DG unit in an unambiguous manner. The fault calculations of NIS as well as the modeling of generator units are developed to support these new functionalities. DG unit data is quoted from the user and network data is obtained from NIS database. The procedure calls normal NIS network calculation and gets the results as an output from the calculation. The procedure continues to go through all necessary studies and detects needs for modifications.

The most essential notice related to the procedure is the iterative nature of the studies. The process returns to the first steps after modifications. This illustrates the complexity of the issue. The procedure does not seek to be a complete solution for all protection-related problems. As most essential issues, the sequence of the studies as well as the actions needed for typical problems are illustrated.

Many of the actions needed could be fully automated so that the NIS system would perform them without any interaction with the user. However, some tasks require data to be set by the user. The most important one of these is definitely the DG unit technical data. Certain safety margins are also needed to be set by the user. Some tasks require confirmation from the user due to their system critical nature although these protection setting changes are made in the planning mode and nothing actual is changed during the process. The user must always decide whether significant changes are made or whether they are used at all.

In a more wide-scale perspective, the studies can also be automated with DMS and SCADA systems for managing network topology changes and exceptional feed situations. The integrated information systems of NIS and DMS share the same database for network information which enables the use of real time network topology information in protection planning. In daily operation activities this could be very beneficial as the system could check the consequences of topology modifications. Even a properly planned DG interconnection may turn to a problematic one as a result of a small change in network topology. After planning the relay settings again these are put in operation via Relay setting tool. Feedback information for a protection setting planning may be offered by fault recordings of relays. This information may be collected via the Relay setting tool and used as an input for a new protection setting task.

4.4.2. Coordinated voltage control

Connections of DG to weak MV distribution networks often experience voltage rise problems. The voltage rise can be mitigated using passive methods such as increasing the conductor size but this can be quite expensive. Network maximum voltage can be reduced also using active voltage control methods (e.g. reducing substation voltage) which in some cases can reduce DG connection costs substantially [Rep 05].

In co-ordinated voltage level management the operation of individual devices participating in network voltage control is coordinated by a centralized voltage controller that consists of a state estimator and a coordinated voltage control algorithm. The centralized controller determines set points for the lower level controllers and sends these to the local voltage controllers through SCADA system.

Figure 4.8 represents the idea of the coordinated voltage control. It is based on adjusting the HV/MV transformer voltage set-value according to the measured network voltages. In practice, the voltage coordination means utilization of the voltage margins between the minimum voltage of the network and the minimum permissible voltage and likewise between the maximum voltage of the network and the maximum permissible voltage. The network voltages are controlled by the operation of the substation OLTC which, in turn, is controlled by the AVR. The operation of the OLTC alters the voltages on all the feeders fed by the HV/MV transformer where the OLTC is mounted. Therefore, the voltage drop margin is determined by the minimum voltage of all the feeders and, of course, the minimum permissible voltage level. Usually the minimum voltage on a lightly loaded network can be found from a feeder where no DG units are interconnected. If a voltage rise problem at some DG unit connection point caused by high production should occur, the AVR relay can order the OLTC to utilize the voltage drop margin, and hence reduce the network voltage. This way the DG production may be allowed to be higher than without coordinated voltage control.

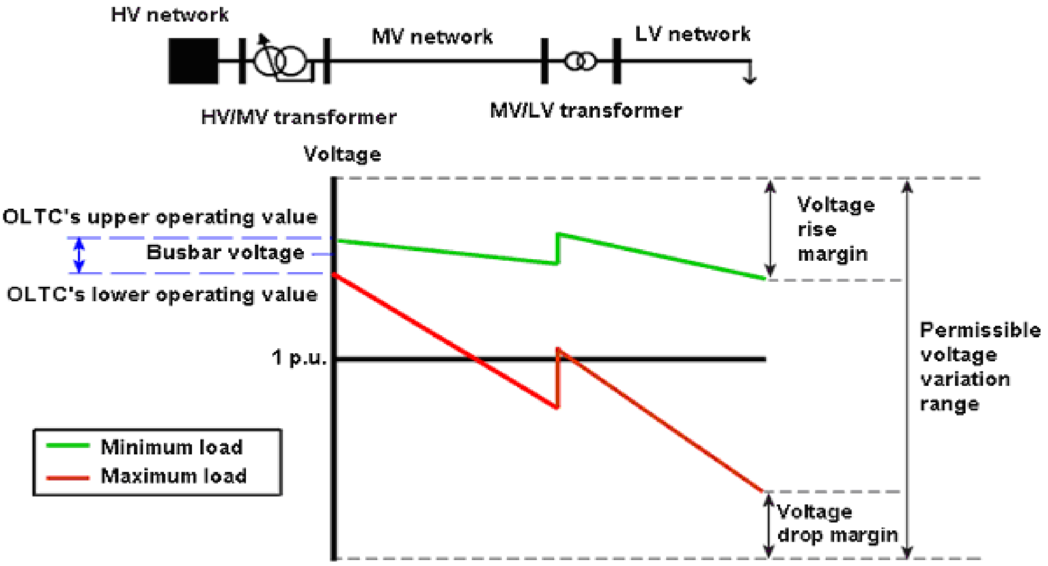


Figure 4.8. Available voltage drop and rise margins. [Rep 05]

The coordinated voltage control algorithm may control the substation voltage and the reactive power of DG based on the state of the whole network [Adi 08d]. The control algorithm comprises two functions: Basic control is used to restore the network voltages to an acceptable level when voltage rise or drop at some network node becomes excessive. Restoring control restores the DG's power factor set point to unity when the network state allows it and normalizes the voltages when the voltage level of the whole network has remained unusually high or low.

Existing SCADA/DMS system may be used to co-ordinate the settings of voltage control devices. SCADA collects current, power and voltage measurements and switching states from primary substations and other possible locations. The inputs to the coordinated voltage control algorithm are network maximum and minimum voltages, substation voltage and generator connection point voltage. The network voltages are estimated using network information obtained from the DMS, load information obtained from the load curves and measurements obtained from the SCADA. Additional information about voltage levels may be obtained e.g. via the meter reading system from energy meters equipped with fast enough communication and accurate enough voltage measurement devices. Measurement information may be utilized in distribution network state estimation [Mut 08]. However it is important to realize that there is not needed additional measurement devices due to co-ordinated control method. The results of state estimation are inputs for the co-ordinated voltage control method which computes the best possible setting values for power factor and voltage controllers. The co-ordinated voltage control method is a function of DMS and the SCADA system adjusts the new settings for controllers. [Adi 08d]

The coordination of controllers requires communication link to each coordinated controller which will restrict the application of method to large DG units and STATCOMs connected to MV network. It is assumed that small DG units connected to LV network are not participating in voltage level management in MV level and hence real time coordination is not needed. The purpose of decentralized voltage control in small DG units is to alleviate possible problems or improve voltage quality in customer connection point. Similarly the power factor compensation units at primary substation are not participating on centralized voltage control because they are controlling the reactive power flow through transformer.

In the most basic version the coordination controller is adjusting the setting values of AVR of OLTC and power factor controllers of DG and STATCOM. Substation voltage is controlled first with OLTC to bring the network maximum and minimum voltages within the feeder voltage limits. Power factor control of DG and STATCOM are activated only if network voltages cannot be normalized using substation voltage control. The coordination controller is based on control rules which have limits for normal and restoring control. Restoring limits are applied to increase voltage level after a DG unit disconnection when the voltage level in the whole network is low. The controller is also capable of preventing the hunting of OLTC by the defined rules to select appropriate parameters for the controller.

The control logic of centralized voltage control must be designed to be failsafe to ensure that when any part of the control and communication systems fails, an unsafe situation will not occur. This may be achieved for example by turning voltage or STATCOM controller for the normal control mode and setting value if communication fails. Then the rest of the failsafe system should be based on DG's normal safety logic.

Figure 4.9 represents the demonstration setup of coordinated voltage control method. The developed control method was implemented in Matlab and connection to SCADA was realized through OPC server. The field demonstration was organized in Koillis-Satakunnan Sähkö Oy (Finnish distribution network company) where setting values of automatic voltage control (AVC) relay of OLTC at 110/20 kV substation and automatic voltage controller of DG unit at the end of one feeder were controlled. In the demonstration, the control was realized only as an advisory tool and the operator executed the suggested control actions. Based on the simulation and demonstration results it can be stated that the coordinated voltage control algorithm defined in this project is able to increase the maximum allowable penetration of DG in an existing distribution network. The algorithm is quite simple and can be easily implemented, for instance, as a part of the DMS. In the Finnish DMS, state estimation is already available and, therefore, only the coordinated control algorithm needs to be added. [Kul 10]

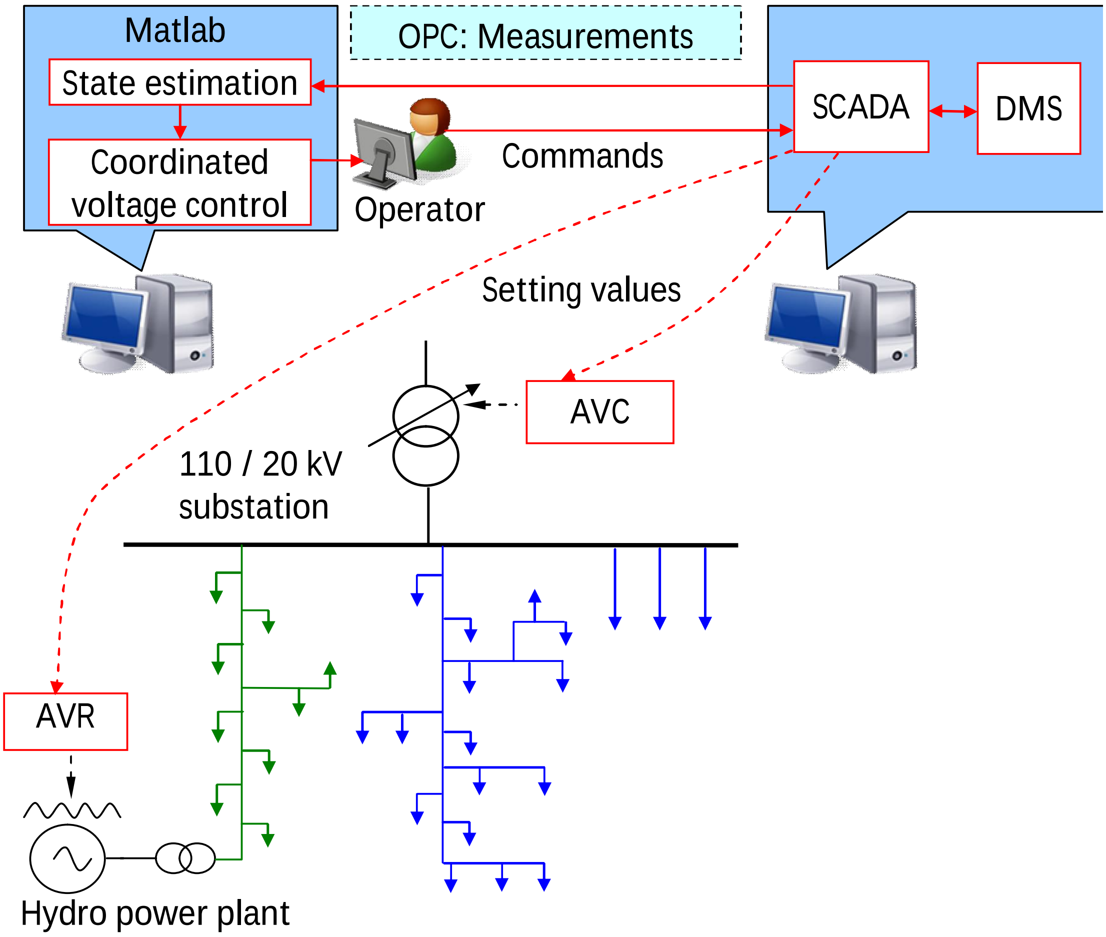


Figure 4.9. Demonstration setup of co-ordinated voltage control method.

4.4.3. Power flow management

This chapter briefly presents the idea of power flow management. The ideas presented in the following are to be utilized in meshed networks or substations with two or more main transformers. Figure 4.10 illustrates a typical British network, where power flow management could be applied.

Managing the distribution network power flows can be used as a means to increase the amount of DG that can be connected to the network. The power flow management concept is based on segregating the network into zones and controlling the power flows between the zones so that the network transfer capacity will not be exceeded. This, of course, necessitates power flow measurements between the zones. The concept divides generation into three categories, namely firm generation (FG), non-firm generation (NFG) and regulated non-firm generation (RNFG), which all are controlled in their own way. [Cur 07]

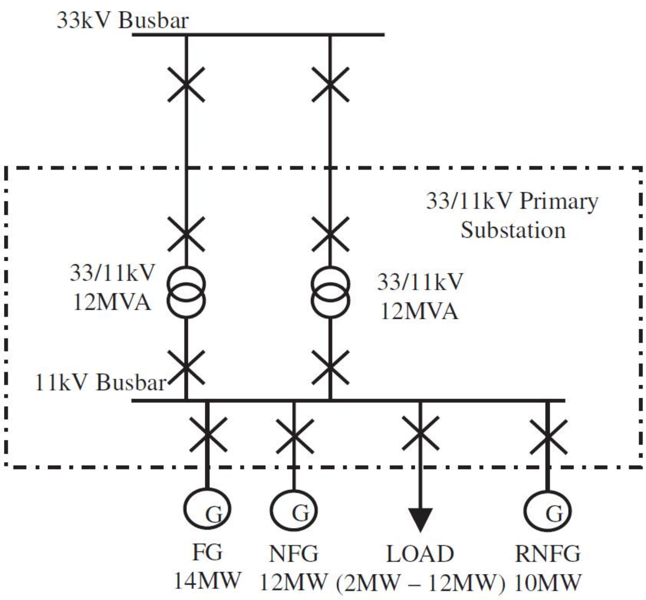


Figure 4.10. Example network for power flow management. [Cur 07]

FG represents the DG units that are always allowed to operate at their full output power. This means that the FG units are allowed to produce their full output even in the case of a fault in the line with the highest transfer rating, while at the same time the consumption is at its minimum. Therefore, it is clear that the permissible DG penetration level will be fairly low if the level is not allowed to exceed FG, and there will, obviously always be spare transfer capacity in the network during normal operation. [Cur 07] This sort of design principle causes no risk for the network operator but it will greatly limit the amount of permissible DG production [Col 03].

The level of allowable DG can be raised by reinforcing the network which, however, is very costly. The level can also be raised by using the network more efficiently, i.e., using the spare capacity that would be unused if only FG was allowed. The NFG units are allowed to operate as they wish during normal operation, but during abnormal contingencies, the NFG units are trimmed or tripped depending on the required power reduction. [Col 03] The mathematical definition of NFG can be described as the transfer capacity of the circuits plus minimum load minus FG. [Cur 07]

Some of the FG and NFG units may be intermittent and thus do not operate at their rated output all the time. Similarly, the load is at its minimum rather occasionally. This leads to the fact that most of the time there would be room for more production in the network in addition to the FG and NFG units. The remaining extra space could be used by RNFG, which is subject to constraining or tripping whenever the network conditions require it. The constraining and tripping are done according to the defined operating margins which take account the variability of the load and generation. The operating margins have two boundaries. On the first limit, namely the trim margin, trimming orders are sent to the RNFG units. The trimming commands are based on the highest rate of change in the power transfer from the zone and the operating delay of the trimming order. If this is not enough, RNFG units within the zone are ordered to be tripped. The theoretical capacity of RNFG is defined as the maximum transfer capacity of the circuits plus the maximum load minus the sum of FG and NFG.

In reality, however, the limiting factor of RNFG comes from economical considerations rather than from the theoretical limit. [Cur 07]

4.4.4. Automatic network restoration

Active networks may also include network restoration procedures like automatic fault isolation and network restoration implemented in substation and feeder automation or in SCADA/DMS. Distribution network feeders are typically radially operated but partially looped which makes automatic network restoration possible utilizing remote-controlled disconnectors. Accurate fault location is the basis of distribution network restoration process. The fault isolation and network restoration are based on this information and hence the accuracy of these functions is totally based on initial data. The accuracy of fault location will however decrease due to influence of DG on fault currents if not properly taken into account.

The purpose of automatic network restoration is to safely restore the power supply to as many customers as possible by proper switching operation after a permanent fault. The process can be divided into two parts. The first phase aims to find out an optimal restoration configuration while the second part consists of the actual switching operation required for the desired configuration. The idea in the first phase is to minimize the number of unserved customers and the outage time while paying attention to the possible constraints. The restoration process constraints encompass the limited transfer capacity, limited available power sources and the required power balance between supply and demand. [Chi 05]

The fault location algorithm may be located either in IED or in DMS. The algorithms may be based on short circuit current and faulty phase measurements, reactance from the IED to the fault, and fault passage indicators. The information processed by IED is sent to DMS in order to analyse possible fault locations in the network. Otherwise the IED should have a complete model of protection zone in order to analyse fault locations. An estimate for the fault location is achieved by comparing the recorded fault currents with the fault currents computed by DMS. This requires that numerical relays, which are capable of recording and sending the fault currents to DMS, are used.

The second phase, namely the switching procedure, can be considerably accelerated by using remote controlled switches for isolating the faulted part of the network. The permanently faulted line section may be roughly isolated and the downstream network restored by backup connections. The field crew is further needed to operate manual switches in order to isolate the smallest possible line section and restore power to as many customer as fast as possible and to repair the faulted line section. The procedure can be completely autonomously operated, for instance, by predefining switching sequences in the SCADA that will be executed after the tripping of a certain circuit breaker. The predefined switching unfortunately has the disadvantage that the circumstances in the feeder concerned must be kept constant. More advanced automatic restoration techniques such as the FI-model (a fully automatic computer model) have, therefore, been developed. Some engineers, nevertheless, are of the opinion that the software should only have an advisory role, whereas the actual switching operation should be in the hands of the operator [Leh 01].

4.4.5. Island operation

Islanding refers to a situation where a zone including DG in a distribution network is isolated from the main system as a result of a fault elsewhere in the network. This way the electricity supply to the customers in the zone may not need to be interrupted at all, which would otherwise be the case if there were no DG units supplying in the zone. This, however, requires that the DG units in the zone are capable of meeting the demand and maintaining the zone voltages and the zone frequency within the permissible limits. The co-ordination between the feeder protection system and DG units is, also, of great importance. [Pre 03]

The sequence leading to islanding usually begins by the operation of protection system after a fault. In such a case, the simplest way to change from grid connected mode to island mode is done by first disconnecting all the DG units in the power island area. The disconnection of the DG units is carried out by the LOM protection which all DG installations need to be equipped with. Then, after separating the power island area by an appropriate switching operation, a desired amount of DG units in the power island area can be reconnected and black started (a certain amount of the generation in the power island needs to be capable of black starting) to feed the loads in the power island. The LOM protection schemes of the DG units in the power island may also have to be readjusted to allow the islanding. The transition to island mode can, however, also be made to happen directly without an interruption. This requires a more sophisticated LOM protection arrangement that can determine when the transition to power island is desired and when it is not. Figure 4.11 illustrates this problem. This practically means that it is necessary to use a communication based LOM protection scheme of some kind. The IED controlling the circuit breaker separating the power island from the main grid would have to be equipped with synchronism check function in order to make it possible to reconnect the power island network back to the main grid without an interruption after the fault clearance. This IED would also have to be able to send control commands to the control systems of the DG units in the power island in order to carry out the possibly needed resynchronization.

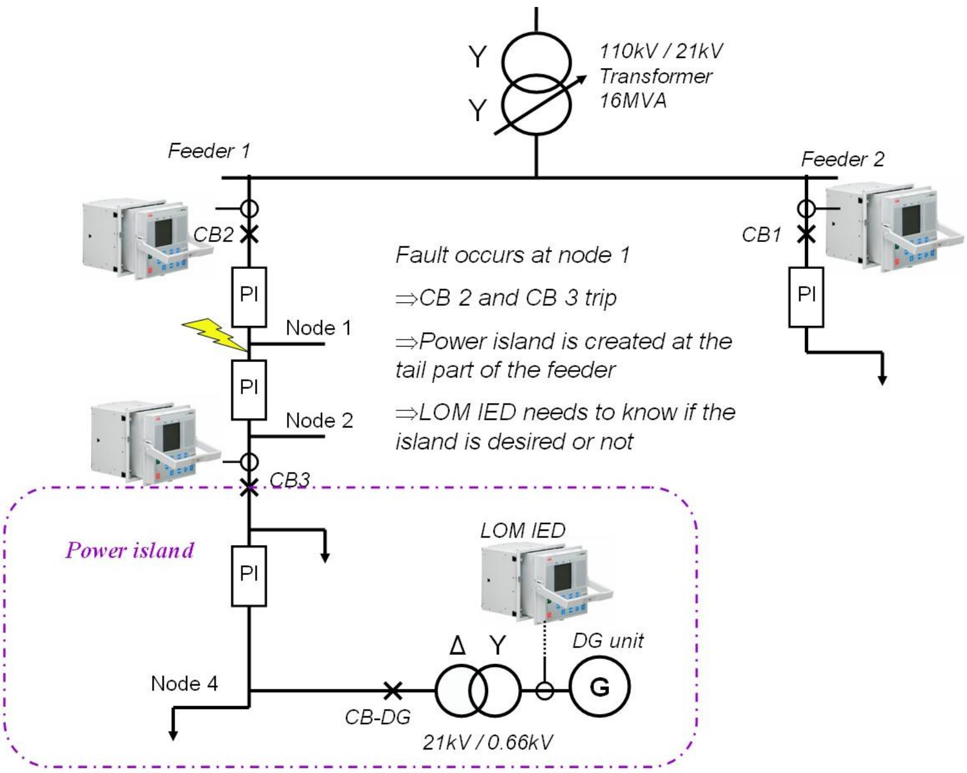


Figure 4.11. A challenge related to loss of mains protection

A planned transition to islanding due to network maintenance reasons is considerably simpler from the protection and automation point of view than a sudden unplanned transition due to a fault. This is because the network configuration as well as the demand in the planned island is known. This means that the functioning of protection systems in the power island can be checked beforehand and possibly needed readjustments can be made. Also the generation in the power island area can be controlled to match closely with the local loads, which is beneficial in the sense that the voltages and frequency in the power island do not drift much from their nominal values during the transition. It is also possible to makes changes to the size of the power island by changing the network configuration so that the generation in the island is large enough to cater the local loads.

Utilizing intended islanding can significantly increase the reliability of the power supply in areas that are capable of operating as an island. This will improve the reliability index reflecting outage time, SAIDI, which is a key reliability indicator for many network operators. If the transition to island operation can be done without blackout also the reliability index SAIFI, reflecting how frequent outages are, will improve. In order to harness such reliability benefits, one must pay special attention to the recloser and remotely controlled disconnector placement. This stems from the fact that the island zones must have adequate generation capacity. Also the nature of the DG units will have to be taken into account. The controllability and control systems of DG units have great influence on the stability of an island. An islanded zone containing only DG units based on intermittent primary energy, such as wind, obviously cannot operate properly. [Pre 03] The island operation requires typically additional control resources like production and load control in order to keep balance between load demand and power production, and maintain appropriate frequency and voltage in the network. The costs of introducing such equipment of course has to be weighted against the benefits expected with island operation.

Intended island operation may also be executed by means of mobile stand-by generation units located in MV network. The focus of this approach is to enhance the reliability and outage cost impacts of intended island operation during long fault interruptions in distribution systems. Effects of this approach were examined by reliability-based software in a test network consisting of two rural feeders. In this study, traditional development actions on a network such as renovating an existing network in different constructions are explored to enable comparison between the effects of intended island operation. According to this study, intended island operation based on mobile stand-by units can increase the reliability of the distribution network and reduce outage costs of the network. These cost savings can be very substantial in relation to operation costs of an island. According to the calculations, the number of positive effects in costs and reliability grows when possibilities to use intentional islanding increase. Based on the study results, it can be possible to reduce outage costs in a more cost-effective way by means of intended island operation instead of renovating the network with more reliable constructions compared to overhead lines. This presents an interesting possibility of using intended island operation to ensure reliable power supply instead of rebuilding obsolete backup connections, but it is also important to notice the effects that the removal of backup connections can cause on a larger scale. The number and quality of the effects are strongly dependent on the start-up time of the island compared to expected outage time or failure repair time. Therefore island operation has to be well-planned to properly ensure its potential. [Ant 08]

The fault currents may be remarkably smaller in island operation compared to the fault currents in normal operation due to the reduced short-circuit capacity connected. This leads to prolonged fault clearance times and difficulties in coordinating the protection settings in the islanded zone because of the reduced difference between load- and fault currents. One way to solve this problem is to switch to different relay settings during island operation. The settings could then be changed back when connecting back to the main system. [Ple 03]

4.4.6. Network Reconfiguration

Distribution networks are usually built in a meshed way but operated in a radial mode due to the simplified protection design. The radial way of operation is realized by opening switches connecting adjacent feeders and thereby isolating the connected parallel feeders. Usually, there are multiple switches along the feeders so that the connection state can be changed, for example, for maintenance purposes. [Col 03] Network reconfiguration can, however, also be used for many other purposes as well. By a proper sequence of switching operations, it possible to maximize or minimize various kinds of objective functions. Such objective functions could, for example, deal with losses, economic and/or reliability indicators, load balancing, voltage control- or possible multipurpose formulations. The optimization of the objective functions will also have to take into account such possible restrictions as min/max node voltages, thermal limits, maximum three phase or earth fault currents, market rules, contracts and etc. Additionally, the optimal configuration could be variable in time. It is, therefore, clear that finding optimums for the kind of objective functions is very challenging. Various methods for solving have, nevertheless, been proposed in literature. [Mut 08]

The increasing amount of DG in the distribution networks has raised the problem of increasing fault levels. This is due to the fault level contribution of synchronous and asynchronous generators used in the DG units. Network reconfiguration can be utilized as a means for mitigating the fault level problems either by reducing the parallel feeds in radial networks or by changing the fault current paths. The fault current path can be changed by opening and closing the switches so that a DG unit is moved electrically farther away from the substation (e.g. moved to another feeder) and thereby, also the fault current infeed to the substation is reduced. The DG unit(s) located on a feeder where fault level is a problem can also be changed to another feeder where fault level is not an issue. Parallel feeder paths in radial network can be reduced by network splitting configurations, which generally are divided into either operating the bus section circuit breaker open or operating a transformer circuit breaker in open standby. Network splitting also has, however, several disadvantages such as increased losses, harmonic voltage levels, flicker, voltage dips and generally decreased power quality because of the increased source impedance. [Col 03] Network reconfiguration affects the state of the network, which has to be taken into account when designing the distribution network state estimation [Str 02] and protection.

5. INFORMATION AND AUTOMATION SYSTEMS AS A HEART OF ANM

Figure 5.1 illustrates the distribution system entity. The dashed line in the figure represents communication links between the control center systems, RTU's and customer automation, which includes AMI's, energy measurement and load control. As illustrated in the figure, SCADA gathers information from various points from the networks for control center monitoring and for further analysis purposes carried out by DMS. [Ver 97]

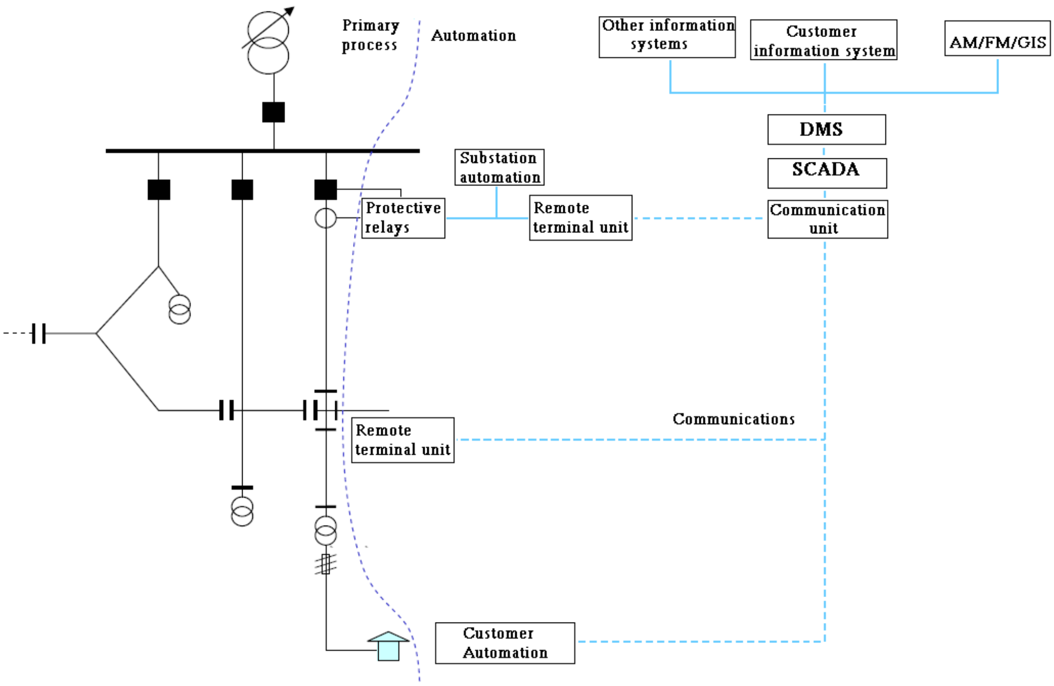


Figure 5.1. The distribution system entity [Ver 97]

5.1. CONTROL CENTRE INFORMATION SYSTEMS

The functional content of these information systems does not have world wide accepted definition but all vendors have their own definitions based on cultural and historical evolution of the information systems. Often the integration degree of information systems varies also in great extent. The following list of functional content of information systems is based on Finnish practice where the integration degree of information systems is relatively high.

5.1.1. SCADA

SCADA is the acronym for Supervisory Control and Data Acquisition. As the name implies, SCADA enables the real-time supervision and control of distribution networks. As illustrated in the Figure 5.1, SCADA gathers information from network for control center and also send commands to control devices at the network. It communicates with the network components such as RTU's, substation automation systems, IED's etc. thus providing information about the status of the network. SCADA also provides the controllability of various network components such as remote controlled switches, capacitor banks and voltage regulators to the network operator. [ABB 08b] The system, however, only includes precise information on the substations and their components, whereas, its information concerning the LV and MV networks is only at general level. [Lak 08] In the event of a fault or overload at some part of the network an alarm will immediately be sent to SCADA so that the control engineer can take appropriate action. The SCADA can also be preprogrammed to perform certain functions and thus fastening e.g. the restoration process. [Lak 95]

The information about the switching state of the network is critically important. SCADA systems, therefore, include a redundancy computer system so that in a case of malfunction in the primary computer the second computer will immediately take control of the SCADA. The SCADA control computers are also equipped with UPS devices capable of supplying power to the computers for a long time. [Lak 08]

5.1.2. Distribution Management System

DMS is a real time high level decision support system based on real time SCADA information integrated with static network data from NIS, geographic information system and CIS. There are, however, many DMS suppliers and the content of the DMS varies from supplier to supplier. The information from NIS is used to create static network model which includes data about location, characteristics and connectivity of network components. Real-time information from SCADA about switching and electrotechnical states is added to this model to create dynamic network model. The SCADA system provides real time data on primary substations and some telecontrolled switches in the distribution network. The geographical information system provides background maps and coordinate data of each network object in MV voltage level and sometimes also in LV voltage level. The data from CIS is needed in load modelling which is typically based on statistical load profiles constructed by the measurements via AMI. The SCADA data needed by the DMS functions includes

- The switching status of disconnectors and circuit breakers
- Electrical (current, voltage, power, etc.), condition (temperature, etc.) and weather measurements from substations and remote locations like telecontrolled switching stations, distribution transformer stations and customers' connection points
- Relay information
- The state of fault detectors

DMS can, for example, be used for managing the field crews [ABB 08a], configuration optimization, planning maintenance outages and calculating fault currents, which can, furthermore, be used for checking the relay co-ordination. If any relay co-ordination violations should come out in the analysis, the relay settings can be reconfigured remotely from the control center. In case of a fault, DMS provides tools such as fault location algorithms and propositions of optimal switching sequence required for restoring the supply. [Lak 95] Highly integrated DMS includes a number of functions like [Ver 97]

- Basic monitoring functions
  - Network state monitoring
  - Topology supervision
- Modelling and calculation techniques
  - Load modelling, state estimation and load forecasting
  - Power flow, fault and reliability analysis
- Fault management
  - Trouble call management

- Fault reporting
- Fault location and diagnosis
- Fault separation and supply restoration

- Operations planning functions
  - Scheduled outage planning
  - Power flow management
  - Volt/var optimization
  - Reconfiguration

DMS performs on-line load flow calculations based on load curves in order to estimate the network bus voltages. The estimation process begins with the estimation of the loads. This is accomplished by using customer group specific load curves which have their respective temperature correlations. The loads, which are adjusted with outdoor temperature measurements, and network data, which is obtained from the NIS, are then used as an input to the load flow calculation. Bus voltages and line power flows are given as a result of this calculation. These values are still relatively inaccurate and, therefore, the feeder loads are readjusted according to the real-time measurements from the substation and other possible locations. The load flow is then recalculated with the readjusted load values in order to obtain a better result. The real-time measurements mainly consist of measurements from the voltage at the substation busbar and from the currents of each feeder. With such a few number real-time measurements it is possible to obtain accurate feeder specific load distribution but the load distribution inside the feeders remains uncertain. The line current and voltage level estimates inside the feeder will then as well be inaccurate. This is problematic since accurate state estimation forms the basis for the ANM as well as for many traditional distribution automation functions. The accuracy of the estimate could be improved by increasing the number of real-time measurements. This, unfortunately, is restricted by the expensiveness of measurement equipment in MV networks. The number of real-time measurements could, however, also be increased by utilizing the AMI devices which many network companies have already installed in vast numbers. In order to obtain the maximum benefit of measurements provided by the AMI devices, certain improvements in the state estimation algorithms would, nevertheless, be necessary and such are proposed in [Mut 08].

SCADA and DMS are widely used above 11kV networks, whereas, the LV networks cannot traditionally be centrally controlled. [Eat 06] This might, nevertheless, soon be changed thanks to the rapidly spreading AMI devices. [Jär 07] The SCADA/DMS combination can also be used for reading the AMI devices which can extend the network management to LV level. The AMI's provide information that could be used for fault indication, for determining the fault location and the isolation of the faulted part of the network. This could remarkably improve the reliability of the supply since traditionally the fault indication and location in the LV networks has been based on customer trouble calls. The AMI's also enable the monitoring of the power quality and provide valuable interruption data for further analysis and other purposes. [Jär 07]

5.1.3. Network information system

A typical DNO applies a NIS for planning and maintaining its distribution network. NIS is a graphically controlled system which integrates network data with calculation functionalities for network planning, maintenance and statistical condition monitoring purposes. The most important objective of such system is to find the optimum between technical and financial matters. The analysis tools include typical fault and power flow calculations. Calculations are typically performed in steady-state with results presented in root mean square values and there might be an interface to provide network data for more accurate simulations. Reliability indices and figures can also be calculated based on fault statistics for each component group combined with background information of network components' location (forest, road or field area) [Pyl 10].

The network planning functionalities include network configuration planning, construction planning and investment planning. The long term state of the network can be monitored with dedicated tools, which exploit the analysis tools. Planned topology changes can also be checked in beforehand. The condition of the network is also managed often with NIS. This includes monitoring the aging of the components and managing the maintenance and renovation actions.

NIS is integrated with other systems to a high degree. In addition to network data and geographical information, calculation functionalities are included. NIS is typically based on geographical information system which includes information about location of network components and lines, technical and other characteristics of components and topology of network components. Graphical user interface represents network components and topology on top of geographical map. NIS is also linked with other data systems like a CIS and a material information system. NIS and DMS often share the same network database and functionalities for instance for network calculation. DMS is intended for control centre usage whereas NIS is generally used for off-line planning and data management purposes.

5.1.4. Other information system

CIS is a customer relationship management system which is aimed for billing, customer service, advising, contract management and marketing. Customer database includes typically information about customers (customer group, consumption data, metering, tariff and billing information) and consumption points. Consumption point, customer group and annual energy consumption data is e.g. used to estimate customer's hourly load profile. This information is an initial data in many calculation functions at NIS.

Utilization of hourly energy measurements and AMI has increased remarkably the amount of information collected from distribution networks. Secondly this information is also utilized for many purposes like asset management and real-time monitoring in addition to billing. Those are the reasons why separate MDM system is needed besides the CIS. The main purpose of MDM is to collect, store and handle measurement data and also manage meter information. Typically the meter reading system is not included into MDM.

Besides the above mentioned information systems, the planning and operation of electricity distribution network requires many other software too. Below is a list of common systems that serve DNO and are commonly integrated with NIS, CIS, SCADA or DMS:

- Mobile workforce management
- Work management systems
- Enterprise asset management systems

5.2. IT ARCHITECTURE OF ANM

Commissioning of ANM requires new solutions in both electrotechnical and Information Technology (IT) domains. These include new protection and measurement devices, communication infrastructure between active resources (e.g. DG) and DNO control centers, sophisticated IT architecture and new software applications. This chapter focuses on IT architecture used in DNO control centers where the most important information systems used today are SCADA and DMS.

5.2.1. Requirements for information systems

Information system is a system consisting of devices, software programs, databases and their interdependencies used to collect, process, store, analyse and mediate information. Also the personnel using the system can be seen as a part of the system. In the operation of the distribution networks, the most commonly used information systems are SCADA, DMS, Network Information System (NIS) and Customer Information System (CIS). Also Meter Data Management (MDM) system is becoming increasingly important due to large-scale installations of the smart energy meters.

Information systems used in the electricity distribution sector are nowadays facing ever growing problems as the amount of data and the number of information systems is substantially increasing. These problems can be seen as increased IT maintenance costs, burdensome and expensive integration projects and different kind of errors (e.g. incorrect customer billing) initiated from information systems. To avoid these problems, the in-formation systems used in active distribution networks should be able to meet requirements common for modern information systems and also the requirements initiating from the active nature of the next generation distribution networks.

Modern information systems used in any branch of industry should be open, expandable, modular, scalable and reliable. They should also offer sufficient performance and usability as well as industrial level information security. There features guarantee that the information systems can be used effectively under different circumstances and that they can adapt quickly to changes occurring in the business.

Openness means that the data transfer interfaces are accurately documented and the documentation is available for the users of the interfaces. Expandable system is a system which can be modified by adding new pieces of software to it without the need of reprogramming the core of the system. Expandability is tightly related to object-oriented programming and modular program structure which means that the system consists of separate components that can be replaced or reused in other systems. Scalable system is a system which offers (or can be easily upgraded to offer) good performance even if the data or user amounts multiply. Information systems with good usability improve the efficiency of the employees and thus the efficiency of the company. Information security is one of the most important features of modern information systems. Security can be improved by well planned firewall segmentation, information security training of the staff and careful architectural planning.

DG increases the needs of measurements and controls of the network devices. Furthermore, DG increases the data amounts processed by the information systems and also creates need for completely new software applications (e.g. coordinated voltage control) and information systems. Also new data lines are needed between DG units and DNO control centers. From common information system requirements, the increasing amount of DG emphases the importance of openness, expandability, scalability and information security.

One aspect of active distribution network is the increasing need for real-time network calculation and accurate state estimation of the network. Real-time state of the network is needed as an initial data for new control applications (e.g. coordinated voltage control). Real-time network calculation requires also real-time data transfer between DG units and DNO control center.

5.2.2. System architecture

Information systems used today in different DNOs can vary significantly from each other. First of all, views about necessary information systems differ from company to company. Secondly, different companies use different information system products developed by different vendors. Third factor is the integration of information systems which means that even if two companies had exactly the same information system products, there can be significant differences in how those systems are set to communicate with each other and with systems owned by external parties. As a result, there are nearly as many information systems and system architecture combinations as there are DNOs.

The problem with current situation is the lack of information model and interface standards. The interfaces between information systems used in distribution network companies are company and product specific solutions customized directly between two information systems. This kind of integration strategy requires data conversions in each interface because there is no standard interfaces and information model in use. As a result, the system architecture becomes complex and difficult to maintain. Advanced standards-based integration strategy and IT architecture is needed.

In the future the information systems used in distribution network companies should be integrated using Service Oriented Architecture (SOA) as a planning method, Enterprise Service Bus (ESB) as an integration technology and IEC 61970 and IEC 61968 as an interface and information model standard.

The essential principle of SOA is to implement information system functions as services which are available for all parties and applications that need them. These services can be owned and maintained by different parties and they should be available regardless of the computer hardware, operation system, programming language and communication line used. In SOA the information systems are integrated by using loosely coupled connections which means that the information systems' dependency on each other is minimized. The ultimate goal of SOA is to improve the interaction between information systems and business processes and thus improve the automation and adaptability of business processes.

ESB is a technology that can be used to implement SOA. ESB is based on Web technologies such eXtensible Markup Language (XML) and Web Services (WS) which makes it compatible with different devices, operating systems and programming languages. ESB is also distributed by its nature as it offers its core services such as message mediation, data transformations, routing, business process modeling and automation, and control of information security as separate service components that can be changed if necessary. The basic architectural differences between the current "point-to-point" integration practice and standards-based SOA that utilises ESB is shown in Figure 5.2. Compared to "point-to-point" integration, ESB is more complex system and its commissioning requires more time, but it's also easier to maintain and it offers better expandability which are important features when the number of the information systems increases.

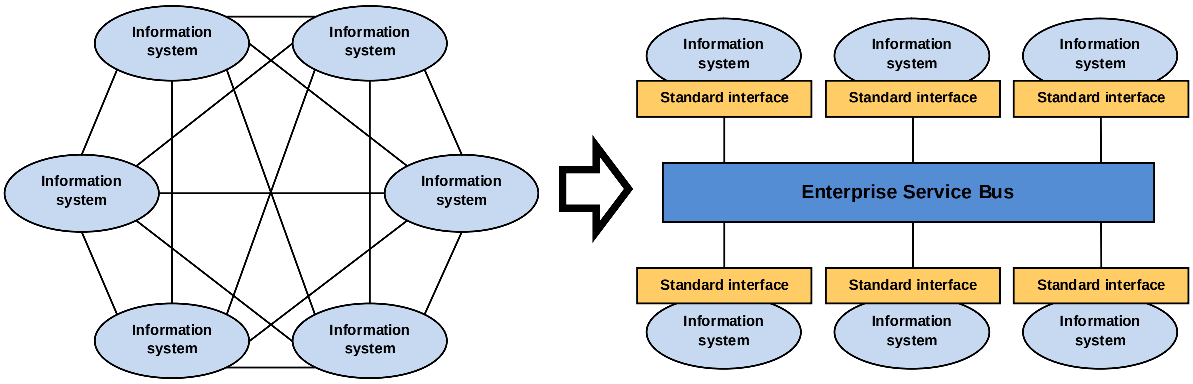


Figure 5.2. Integration strategy needs to be changed from "point-to-point" to standards-based SOA.

The most promising candidate for the standard interfaces and information model is known as CIM (Common Information Model). The CIM consists of two IEC standards (IEC 61970 & IEC 61968 [iec b, iec c]) which are still partly under development. The core of the information model is specified in IEC 61970-301 and the extensions to the model needed in distribution networks are specified in IEC 61968-11. The interfaces for different business processes used in distribution network companies are specified in parts 3-10 of IEC 61968.

5.2.3. Vision of the IT architecture of ANM

The vision of the IT architecture of ANM is depicted in Figure 5.3 [Kot 10]. In this vision, the system architecture is based on SOA, ESB and CIM. The information systems communicate with each other through XML formed messages and files using asynchronous query/reply and publish/subscribe message exchange patterns. The information system and application interfaces are based on parts 3-10 of IEC 61968 and implemented as Web Services. The services offered by different information systems and applications are stored in a service register to ease the discoverability of the services.

Databases, software applications and user interfaces are separated from each other which give possibilities to create task specific user interfaces. User interfaces can also combine services from a number of different information systems and applications. This is useful for example in control centers where it can be used to unify the functionality of SCADA and DMS into one unified user interface.

With standardized interfaces and integration architecture based on distributed services, the currently used large information systems could be replaced and complemented with separate compact applications. This would increase the competition between the information system vendors and make it easier for smaller vendors to get new software products to the market. As a result, DNOs could choose and buy group of inexpensive task specific software applications that best suit their needs instead of large information systems.

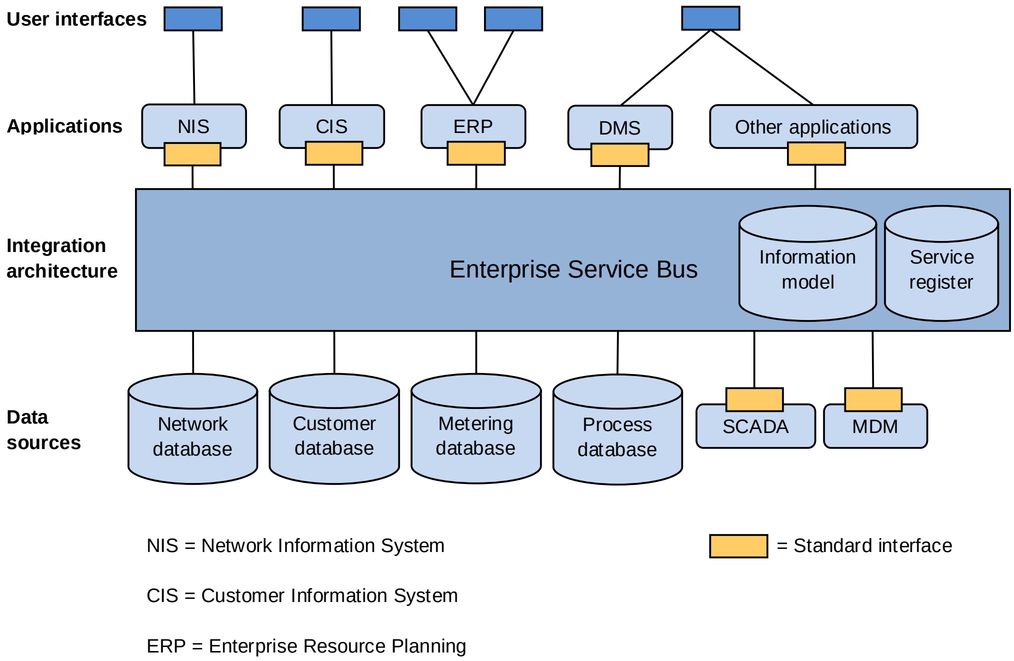


Figure 5.3. IT architecture of ANM.

5.2.4. Advantages and possible drawbacks

The most significant benefits gained from the utilization of open standard interfaces and new system architecture are the reduction of the total amount of interfaces, the acceleration of the commissioning of new information systems and business functions and the clarification of the communication between network companies and service providers. All these things reduce the maintenance costs of information systems and improve company's ability to react to changes in business processes and business environment. Other useful benefits include maintaining information only in one place, real-time data management, getting rid of unnecessary manual work and better exploitation rate of information systems. In addition, usage of interface and information model standards and Web Services ease outsourcing and usage of software rental services.

Possible drawbacks related to change of IT architecture include risk of having difficulties in implementation of new technology that can result in increased project costs, risk of resistance to change by personnel, need for company specific extensions to standards as the standards can not be made to cover all the details needed in every company, and increased system complexity. The risks can be minimized by following a roadmap that includes best practices of SOA implementation. What comes to standard extensions and system complexity, these drawbacks are outweighed by the advantages when the number of information systems to be integrated becomes large.

5.2.5. Roadmap towards new IT-solutions

The information system integration projects affect the operation of whole company and should therefore be well planned. Exact guidelines about how an integration project should be done cannot be given, but certain well-known best practices that should be used are widely available. These general best practices can be seen as a roadmap:

1. All related parties should be involved in the integration process

- Technical oriented personnel in the company
- Business oriented personnel in the company
- Managers of the company
- External IT system integration specialists with experience of successful SOA projects

2. The current IT architecture used in the company should be accurately analysed

- There is no one best solution for all business domains and companies

3. Company wide technical and strategic guidelines for IT system integration should be set

- Selection of standards and data transfer techniques to be used
- Both technical oriented and business oriented personnel should be involved
- Ensures in large companies that separate integration projects result in compatible systems

4. Implement SOA incrementally

- Start by testing SOA principles in small scale SOA projects
- Don't try to change the whole IT architecture in one project
- Combination of "top-down" and "bottom-up" approaches
    - First identify and model business processes ("top-down")
    - After that, identify individual services in the information systems ("bottom-up")
    - Finally, orchestrate individual services to groups of services so that they form high-level services matching the needs of business processes ("meet-in-the-middle")

5. Build interface adapters for legacy IT systems

6. Add existing information systems to new IT architecture

7. Require standard interfaces from IT system vendors for all new information systems

5.3. AUTOMATION SYSTEMS

Distribution network automation consists of substation, feeder and customer automation systems.

5.3.1. Substation automation

Substation automation system plays a vital role in whole distribution automation system to provide interface to primary substations, both for local and remote access, and some automated functions to ease and secure the operation of a substation and process behind it needing the power supply. A substation automation system is often considered to consist of intelligent protection and control devices (IEDs), communication network inside the substation and equipment on the station level to handle information for the whole station. Its main functionalities are:

- Local monitoring and control HMI (Human-Machine-Interface) of the substations
- Communication gateway to interface the secondary (automation) system to other automation systems higher on the hierarchy (e.g. network control centre)

- Automated functions running centralized for the whole station, like busbar transfer sequences, interlocking and centralized load shedding.

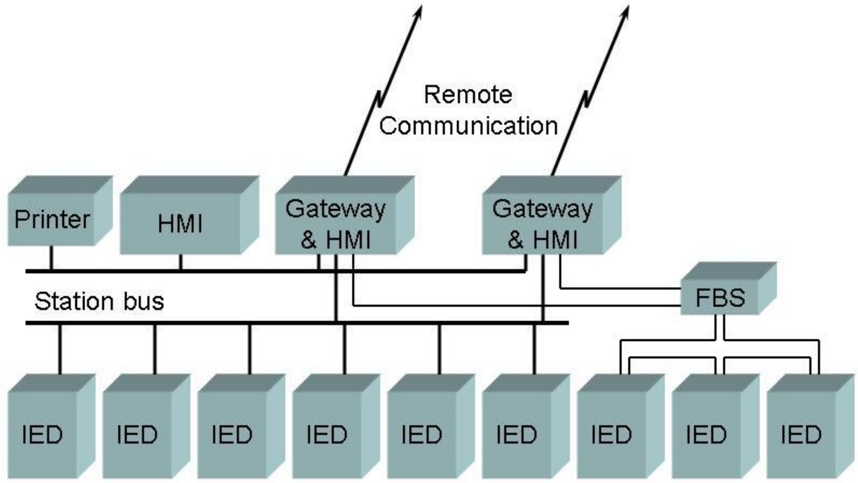


Figure 5.4. Substation automation example.

The task of a station communication gateway in a substation is to interface the system to SCADA. Functionality achieved with interfacing is primarily remote control and monitoring of the substation. In some cases all the functionality which is available on local substation HMI is required on remote end, but there are also cases where only essential information is needed. The basic communication gateway functionalities are: protocol conversions (e.g. Modbus to IEC 60870-5-101/104), filtering too frequent changes on substation side, combining signals and transferring of files or disturbance records. Communication gateway is also a critical device from information security viewpoint.

The Station HMI is used to collect all the needed information from the IEDs in the substation to one centralized location for further distribution and archiving. Users can then use the HMI to e.g. perform changes in the switching state, supervise the process, change protection settings, analyze the historical data, or monitor system health.

Centralized interlocking functions in medium voltage are very important in order to ensure proper and safe behaviour of the whole substation. The main target is to ensure or increase a safety of operational personnel when working in substation or to avoid malfunction operations that could lead to unwanted tripping of the feeders and thus to loose the supply of some feeders or whole substation. The primary task of the automatic change over transfer is to ensure continuous power supply to essential electrical equipment by changing over from a main to a stand-by feeder as fast as possible and thus to avoid a interruption of power supply to consumers. The primary function of the load shedding system is to ensure the availability of electrical power to all essential and most critical loads in processing plants. This is achieved by the switching off of non- essential loads. A lack of electrical power can be caused by loss of generation capacity or disconnection from the public distribution or national grid supply.

Modern multi-function terminals (IEDs) provide much more functionality, performance and scalability than traditional single-function protective relays. Modern IEDs perform an important role as the primary process interface, data acquisition unit, processing unit, reporting unit and control unit in a distribution automation system. Modern IEDs include a large number of protection functions that meet the needs of various applications. In addition, they include control, measurement, power quality monitoring and condition monitoring functions for distribution network and its components.

The main purpose of a relay protection system is to recognize any abnormal power system condition, or abnormally operating system component. Based on the information gathered, the protection system will initiate corrective actions that return the system to its normal operating state. Relay protection does not prevent network faults from arising, but it is activated when something abnormal has occurred in the power system. However, careful selection of protection functions and methods improves the performance and the reliability of the power system, thus minimizing the effects of network faults and preventing the disturbance from spreading to the healthy parts of the network.

Control functions of an IED are used to indicate the position of switching devices, that is, circuit breakers and disconnectors, and to execute open and close commands for controllable switching devices in the switchgear. IED allows position information from the circuit breakers and the disconnectors to be transmitted to the remote control system. Controllable objects, such as circuit-breakers, can be opened and closed over the remote control system. Position information and control signals are transmitted over the station bus and they can be used for inter-bay interlocking schemes. A feeder protection and control IED may include a power factor controller that is used as an intelligent control unit for controlling the switching of capacitor banks based on the reactive power requirements of the load. A transformer protection and control IED may include automatic voltage regulation function for on-load tap changer control. There are also IEDs for automatic high-speed busbar transfer systems that are used to ensure maximum service continuity, supplying the power users uninterruptedly.

The measured values of IED (e.g. phase currents, phase-to-phase or phase-to-earth voltages, neutral current(s), residual voltage, network frequency and power factor), related alarms and accumulated history values can be indicated locally in the front panel of the IED and reported remotely through the distribution automation system.

Communication interfaces are used most often for IED to communicate with station level devices, like HMIs and gateways. However, some communication protocols also support so called horizontal communication, meaning that IEDs are communicating with each other. Additionally, together with IEC 61850 standard, new applications are appearing using also digital communication between sensors and IEDs, this is often called process bus. The interfaces concerning IEDs are (see also Figure 5.5):

1) protection-data exchange between bay and station level

2) protection-data exchange between bay level and remote protection (e.g. line differential protection)

3) data exchange within bay level

4) CT and VT instantaneous data exchange (especially sam-ples) between process and bay level

5) control-data exchange between process and bay level

6) control-data exchange between bay and station level

8) direct data exchange between the bays especially for fast functions such as interlocking

Ethernet is becoming the prevalent communication interface for all automation devices. Major advantage and pullthrough for Ethernet it is the extremely wide usage in everywhere in ICT systems. Hundreds of vendors for hardware, software and protocols utilizing Ethernet exist. This also makes it cost efficient. However, it must be noted that EMC issues in substation automation have to be carefully taken into account on the designs and often much more expensive fiber-optic Ethernet infrastructure must be used. Ethernet is used together with several protocols, and being a true bus, several protocols can co-exist- on the network and be utilized by the IEDs. For substation automation, the most remarkable protocols utilizing Ethernet are IEC 61850, Modbus/TCP and DNP 3.0 over LAN/WAN, where the two latest ones are specializations of corresponding serial versions of the protocols.

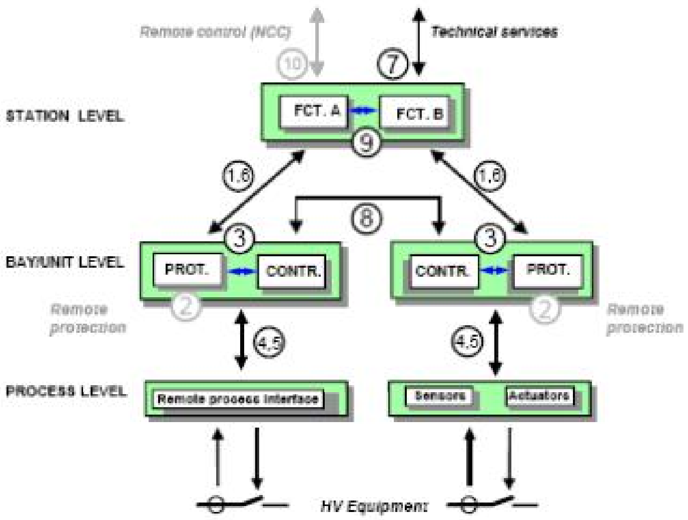


Figure 5.5. Interfaces according to IEC 61850-5.

5.3.2. Feeder automation

The overall aim in fault management is to locate and isolate a fault and to restore the unfaulted part of the network as quickly as possible in order to reduce the outage costs and to satisfy the quality of supply requirements. The outage costs can be affected by designing and constructing networks subject to a minimum number of faults (e.g. using cables, avoiding forests in the case of overhead lines), or by installing more distribution automation devices (e.g. a fault detector and remote facility for each line-switch) and software tools to decrease the outage time. In an existing fault situation fast fault location is essential in reducing the outage time and costs. The known location of the fault makes it possible to restore the unfaulted network quickly by back-up connections, where they exist.

A fault is usually detected when the protection at a HV/MV primary substation opens a circuit breaker of the faulted feeder. A temporary fault is normally cleared up by the autoreclosing facility of a protection relay. The control center operator is responsible for fault location and network restoration in the case of a permanent fault. The operator receives a more or less informative alarm and data on the fault (i.e. often only the operated circuit breaker). The fault location is traditionally performed using the "experimentation method" (i.e. "trial switchings" or "divide and conquer").

The use of remote controlled disconnectors in the experimental switchings speeds up the fault location process considerably, because the fault is located in roughly a few minutes while a wide area of the network is restored. The function of a fault detector is to tell whether the fault current has passed it or not. When this information is collected to DMS, it is possible to make reasoning where the possible fault locations are situated. Automatic sectionalizers are able to isolate a faulted branch in the network using the time delayed automatic reclosing facility of the circuit breaker. Remote controlled disconnectors equipped with fault detectors can also be made to isolate a faulted branch automatically. In addition to providing basic protection functions, the relay can register different values useful in fault location, send this information to SCADA/DMS for further analysis or estimate the fault location itself if appropriate feeder impedance data is available.

In a MV-feeder fault situation the DMS receives information on the faulted feeder from the SCADA based on the relay and circuit breaker operations. The available data is transferred from the SCADA to the DMS, which includes a detailed model of the faulted feeder and inferences the possible fault locations. The sequence from the opening of a circuit breaker caused by a fault to the DMS screen illustrating the possible fault locations is carried out automatically without any operator actions. In short circuit faults the calculated fault distance is the main information used in the inferencing. The electrical distance between the feeding point and the fault location is determined by comparing the measured short circuit current and the type of fault with the calculated fault currents. The possible fault locations are ranked using information on other sources (e.g. fault detectors, terrain conditions, weather information). The fault management application proposes the switchings for locating and isolating the fault. The operator makes the actual decisions and performs the switchings using the SCADA system or staff working on the network.

In addition to fault management, MV network and MV/LV secondary substation monitoring is becoming more and more important. Supervision, control and measurement functions nowadays common at HV/MV primary substation will also be extended to MV network and MV/LV secondary substation. Also other devices like fault indicators, power quality monitoring devices and disturbance recorders may communicate with control centre utilizing the same infrastructure.

5.3.3. Customer automation

Traditionally Automatic Meter Reading (AMR) and DMS have been separate systems without any integration with each other. The primary role of AMR has been to provide energy consumption data to the utility for billing and balance settlement purposes. AMR system has also been used for load control in some installations. So far automatic monitoring and control center measures by the DMS have been used mostly for operating MV networks. A fault in a LV network is cleared automatically by a blown fuse, but no information about that is received to the control center. The existence of a LV network fault is usually indicated only by customer calls.

The present AMR meters offer the platform (i.e. the infrastructure and communication) to determine and develop new upper level functions (see Figure 5.6). These will be used in developing network asset management, market enhancement and customer service. First implementations of advanced AMR systems (AMI) have already changed the function of the basic energy meter to be a smart terminal unit and gateway that enables real time two-way communication between customers and utilities. In advanced meters, alarms based on exceptional events, i.e. network faults and voltage violations are enabled. Meters may also have some protective functions for safety reasons. The use and integration of AMI in network operation can be seen as an extension of SCADA and distribution automation to the LV level. As Figure 5.6 illustrates, AMI system can be utilized in many functions of a distribution company, e.g. to support network operation (e.g. automatic LV fault indication, isolation and location, precise voltage and load data), network planning and asset management (e.g. exact load profiles for network calculations), power quality monitoring (e.g. interruptions, voltage characteristics), customer service, and load control in addition to traditional use in billing and load settlement.

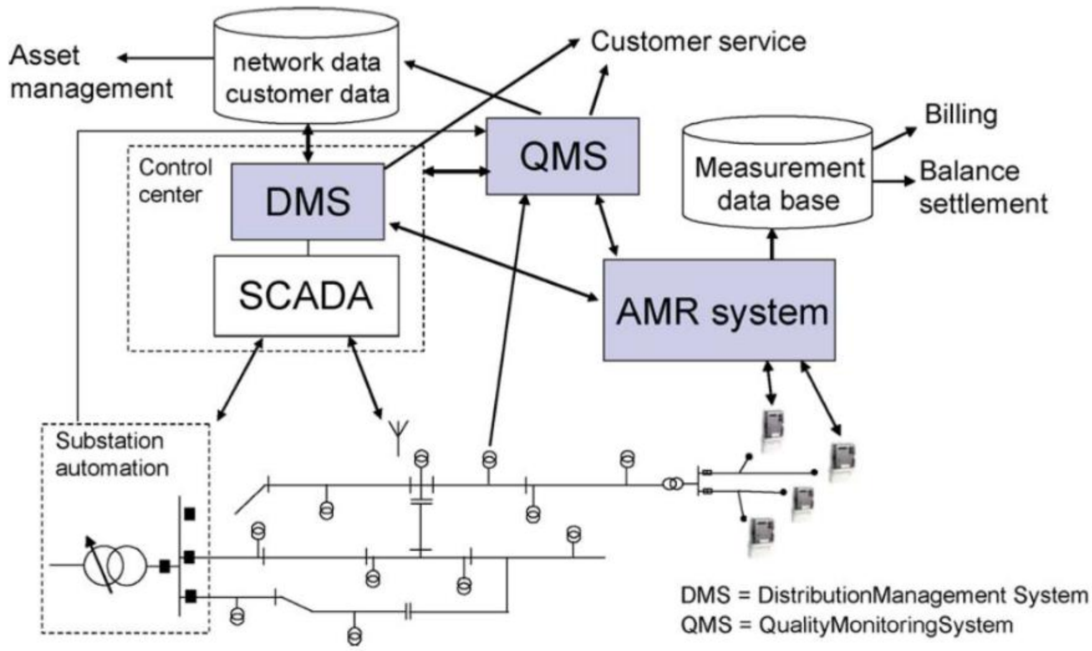


Figure 5.6. Integrated information systems for comprehensive network management.

AMI gateway [Jär 08] would provide multitude of opportunities for electricity network monitoring and operation. AMI data may for example be utilized in LV network outage and power quality monitoring [Try 08]. The system recognizes the blow of fuse or the neutral wire failure in LV network in few minutes by AMI which sends an alarm via GPRS for DMS. The same infrastructure may also be utilized to switch customers off during a neural wire failure in order to avoid safety risk and to prevent equipment failures. Other applications for the AMI gateway are for example demand response and frequency reserve ancillary services realized by direct load control [Rau 08]. AMI data may also be applied in DMS state estimation [Mut 08]. AMI gateway might also be a practical solution for the operation and supervision of small scale DG.

6. CONCLUSIONS

6.1 SUMMARY

The network management concept presented in this report is based on existing distribution network management concept completed with new features and functions. The existing distribution network management concept is a complex system of devices, automation systems and practices which include protection relays, controllers, telecommunication, substation and feeder automation systems, control centre software like SCADA and DMS, and guidelines for network planning and operation. Network management includes the automation of network operations like automatic supply restoration and the increment of observability and controllability of distribution network via measurement, control and communication. The existing management system includes three layers: protection system, automatic control system (decentralized) and area control level (centralized).

The utilization of ANM requires development of new methods for the electric distribution network management including DG i.e. management of active distribution network to maintain networks within acceptable operating parameters. When the distribution network is managed according to the ANM method the interactions of different active devices can be planned and controlled to benefit the operation and stability of the network. With proper interaction of devices the overall system performance can be improved from presently used practices.

The new features and functions of distribution network management are based on the control and cooperation of active devices. The goals of developed ANM method are to ensure safe network operation and to increase network reliability in networks with DG, to maximize the utilization of the existing networks with bottleneck caused by voltage issues, and to maintain the required level of power quality despite non predictable power production or consumption. In order to achieve these goals there are needed to develop individual technical solutions (protection, voltage control and STATCOM) and validate the combination of technical solutions (ANM method).

The solutions developed in the project may be used on their own or together. The real-time simulations demonstrate how the technical solutions interact with a power system with much DG. They also illustrate how some technical issues are closely related such as loss-of-main protection and fault ride through. Demonstrations have also shown that active network is feasible today at least in specific applications. This means that existing device, automation and IT systems are capable to provide active network features which are part of overall active network management.

6.2. FROM PASSIVE NETWORK TOWARDS MORE ACTIVE NETWORK

The change from passive to ANM will not happen overnight because of the extensiveness of the existing distribution networks. The change will rather take place in suitable steps as it seems to be happening in the UK, where the active control installations have so far been mostly stand-alone units controlling a single DG unit connected to a single feeder. While planning these kinds of stand alone installations designed for the optimization of the existing network, one should also consider the future requirements for the active network. The distribution of logic around the network, nevertheless, increases the reliability of the system in the sense that the seriousness of malfunction in the communication system is reduced. [Rob 04]

The DTI report [Rob 04] considers the active control to be made out of three equally important stages, namely active unit, active cell and active network. The active unit controls a local device based on local measurements. This could be implemented by a RTU or similar device capable of standard SCADA communication that would be programmed to carry out appropriate local controls and possibly reconfigured by downloading data from the main SCADA. An AVR relay controlling an OLTC of a transformer, for example, could form an active unit. The next stage upwards on the priority level, namely the active cell, consists of multiple active units that are controlled by an overriding control system that is above the unit controllers. Information from the main SCADA could be extracted to be used as an input in the local logic for broader optimization. Such a system could, for instance, be comprised of multiple transformers, whose AVR relays are centrally coordinated in order to optimize the voltage profile for all customers. Eventually, active network, which is formed by a group of active cells, would be on the top of the priority stages. This level could be used for coordinating adjacent networks, in other words, adjusting the network for loadflow and minimizing the effect on adjacent network. [Rob 04]

Integration of new active devices into the existing distribution automation and IT systems is an important issue. The active network might be based on only local logic, but the most benefit of active network may achieved by co-ordinated management of active devices like this project has demonstrated in few cases. It is not possible to replace the whole automation and IT system at once therefore active network and ANM requires continuous evolution instead of a revolution. The integration of active devices into automation and IT systems should be based on open interfaces and standardized protocols in order to ensure easy integration of all kind of devices and systems without replacing the core parts of automation and IT system every time a new functionality of ANM or a new active resource is connected to the automation and IT system.

ANM is not only automation or IT project. The most important decision which DNO should make is related to distribution network planning and operation philosophy. Should the network capacity come from passive network elements like wires and transformers or is it possible to utilize active resources like DG, load control or compensators in ANM? How much DNO may trust third party active resources? It is natural to trust technology and philosophy which is well known and all resources are in direct control of operator. However this thinking might become very expensive for all participants when the penetration of DG, electrical vehicles and other new resources will be connected in the distribution network in large extend. The challenge is to decide the moment when e.g. a new DG connection is handled by ideas of active network. Investments are typically high for the first installations because new interfaces, platforms, etc. are needed. Also the need for learning new things is the highest during the first installations.

Active network is feasible already today. There is not need to wait something which solves the challenge. The only way to get real knowledge about what active network should look like is to start working towards it. The first step towards active network and ANM does not have to be huge. The next step will tell us more. If we wait until someone tells us what the active network should look like, we actually never start building it. The 21th century chance to build active network will be lost because the distribution network structures were rebuild by passive network elements and ideas.

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