Role of Protective Relaying in the Smart Grid
Report to the Main Committee

Working Group C-2 of the System Protection Subcommittee,
Power System Relay Committee

Chairperson: Alex Apostolov **Vice Chairperson:** Roy Moxley

Members: G. Antonova, J. Ariza, Phil Beaumont, Sukuman Brahma, Craig Bryant, J.F. Burger, J. Csisek, Catherine Dalton, T. Day, Kevin Donahoe, Fred Friend, J. Galanos, Rafael Garcia, Juan Gers, George Gresko, Shinichi Imai, M. Janssen, Dylan Jenkins, Jack Jester, Jerry Jodice, M. Kezunovic, S. Klein, Mike Kockott, L. Kojovic, Raluca Lascu, Tony Leszczynski, A. Martin, M. Meisinger, R. Midence, A. Mulawarman, Paul Myrda, Pouria Naisani, D. Nordell, Damr Novosel, Vajira Pathirana, M. Reichard, Imran Rivzi, S. Sambasivan, T. Sidhu, Mark Simon, T. Smith, Dean Sorensen, Farajollah Soudi, Mark Taylor, Damien Tholomier

1 Contents

PSRC WG C2

Report: Role of Protective Relaying in the Smart Grid

Assignment:

Identify the functions and data available in Protective Relaying Devices (PRD) that are used at different functional levels and different applications and can be used within a Smart Grid. Describe the use of interoperable data formats for protection, control, monitoring, recording, and analysis.

2 SMART GRID DEFINITION

The electric power industry is going through a period of a major shift in the use of advanced technology in an effort to develop a smarter grid that can successfully meet the challenges of today and the future. However, many people do not know or understand that for more than two decades, the protection, automation, and control community has been implementing advanced microprocessor based multifunctional intelligent electronic devices (IEDs) that can help speed up and reduce the costs of the deployment of the Smart Grid.

The goal of this document is to highlight the state-of-the-art in PRDs and give some ideas on how they can support the concept of the Smart Grid, including operations and asset management based on data and information available from multifunctional IEDs.

The existing transmission and distribution system in the United States uses technologies and strategies that are many decades old and include limited use of digital communication and control technologies. To address this aging infrastructure and to create a power system that meets the growing and changing needs of customers, the Modern Grid Initiative (MGI) seeks to create a modern - or "smart" - grid that uses advanced sensing, communication, and control technologies to generate and distribute electricity more effectively, economically and securely. The Smart Grid integrates new innovative tools and technologies from generation, transmission and distribution all the way to consumer appliances and equipment. A modernized grid would create a digitally-connected energy system that will:

- Detect and address emerging problems on the system before they affect service
- Respond to local and system-wide inputs and have much more information about broader system problems
- Incorporate extensive measurements, rapid communications, centralized advanced diagnostics, and feedback control that quickly returns the system to a stable state after interruptions or disturbances,

In order to have a common understanding of the topic, within the document a definition in the US Energy Independence and Security Act (2007) is used. This Act describes the policy of the United States to support the modernization of the Nation's electricity transmission and distribution system to maintain a reliable and secure electricity infrastructure that can meet future demand growth, and can achieve each of the following:

1. Increased use of digital information and controls technology to improve reliability, security, and efficiency of the electric grid.
2. Dynamic optimization of grid operations and resources, with full cyber-security.

3. Deployment and integration of distributed resources and generation, including renewable resources.
4. Development and incorporation of demand response, demand-side resources, and energy-efficiency resources.
5. Deployment of ‘smart’ technologies (real-time, automated, adaptive, interactive technologies that optimize the physical operation of appliances, consumer devices and industrial equipment and processes) for metering, protection, monitoring, control and communications concerning grid operations and distribution automation.
6. Integration of ‘smart’ power system devices (transformers, breakers, etc.).
7. Integration of ‘smart’ appliances and consumer devices.
8. Deployment and integration of advanced electricity storage and peak-shaving technologies, including plug-in electric and hybrid electric vehicles, and thermal-storage air conditioning.
9. Provision to consumers of timely information and control options.
10. Development of standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid.
11. Identification and lowering of unreasonable or unnecessary barriers to adoption of Smart Grid technologies, practices, and services.

Meeting future demand growth and achieving each of these 11 items listed above, together characterize a Smart Grid.

3 WHY DO WE NEED A SMART GRID

3.1 What’s Wrong With the Grid Today?

The power in North America has generally been highly reliable; however, the demands placed on the Grid have continued to increase, and additional investments in the grid may not have always matched the increased performance requirements. While transmission spending, for example, has increased in recent years, it still lags the pace of increasing energy consumption.

The grid is also not performing at the same level it was decades ago. Energy losses in the transmission and distribution system have increased dramatically from the 1970’s to the beginning of the new century. There are also operational and security risks in the design of the grid with centralized generation plants serving distant loads over long transmission lines. However, adding more distributed resources (such as variable sources like wind and solar), and adding co-generation (introduced by large industries as one of the most common forms of energy recycling), presents new operational challenges.

Meanwhile, changes in the way electricity is bought and sold at the wholesale level have drastically increased the amount of power being traded between regions. Even the way we use electricity has changed. In our digital society, power quality is of much greater importance than it was just 15 years ago, both for end consumers and businesses (i.e. micro chip manufacturing), where even small disturbances in the power supply can have detrimental effects on production.

Taking all of these factors into consideration, it becomes apparent that the grid we know today is insufficient to serve us in the future.

3.2 Problem Definition

Driving forces to modernize current power grids can be divided in the following general categories.

- Increasing reliability, efficiency and safety of the power grid
- Enabling different ways that existing central generation will be employed
- Enabling decentralized power generation
- Flexibility of power consumption at the client's side
- Renewable energy – plug-in electric vehicles, solar panel and wind turbine generation, energy conservation construction (1) (2).

3.2.1 Network vs. Hierarchy – The Modern Grid Topology

(3) Today's power systems are designed to support large generation plants that serve faraway consumers via a transmission and distribution system that is essentially one-way. But changes in today's grid have already shown that the grid of the future will be a two-way system where power generated by a multitude of small, distributed sources—in addition to large plants—flows across a grid based on a network rather than a hierarchical structure. Just as the Internet has driven media from a one-to-many paradigm to a many-to-many arrangement, so too will the Smart Grid enable the changes necessary to facilitate a similar shift in the flow of electricity.

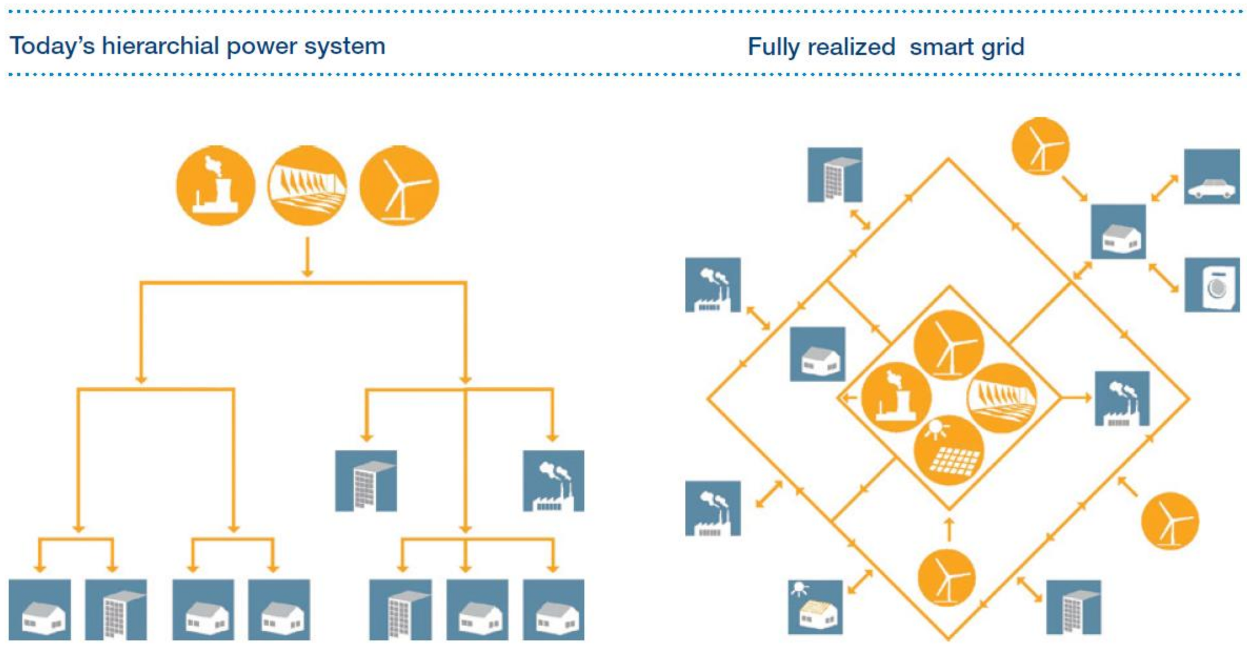

Figure 1. Power system hierarchy

The diagrams above illustrate this shift. In the first, we see today's hierarchical power system, which looks much like an organizational chart with the large generator at the top and consumers at the bottom. The second diagram shows a network structure characteristic of a fully implemented Smart Grid.

4 SMART GRID FUNCTIONS

According to the United States Department of Energy's Modern Grid Initiative (MGI) report [3], a modern Smart GridSmart Grid must:

- Be able to heal itself
- Motivate consumers to actively participate in operations of the grid
- Resist attack
- Provide higher quality power that will save money wasted from outages
- Accommodate all generation and storage options
- Enable electricity markets to flourish
- Run more efficiently
- Enable higher penetration of intermittent power generation sources

4.1 Minimize System Disruptions

Using real-time information from embedded sensors and automated controls to anticipate, detect, and respond to system problems, a Smart Grid can automatically avoid or mitigate power outages, power quality problems, and service disruptions. Power networks can be designed (through the use of interconnected topologies) such that failure of one part of the network will result in no loss of supply to end users. (4)

4.2 Consumer Participation

One aspect of a Smart Grid is, in essence, an attempt to require consumers to change their behavior around variable electric rates or to pay increased rates for the privilege of reliable electrical service during high-demand conditions. A Smart Grid incorporates consumer equipment and behavior in grid design, operation, and communication. A Smart Grid also enables consumers to better control appliances and equipment in homes and businesses through means of interconnected energy management systems. This results in improved energy management and reduced energy costs for consumers.

Advanced communications capabilities will equip customers with tools to exploit real-time electricity pricing, incentive-based load reduction signals, or emergency load reduction signals.

The real-time, two-way communications available in a Smart Grid will enable consumers to be compensated for their efforts to save energy and to sell energy back to the grid. By enabling the integration of distributed generation resources like residential solar panels, small wind and plug-in hybrid, Smart Grid assists a revolution in the energy industry by allowing small players like individual homes and small businesses to sell power to their neighbors or back to the grid.

The same will hold true for larger commercial businesses that have renewable or back-up power systems that can provide power for a price during peak demand events, typically in the summer when air condition units place a strain on the grid.

4.3 Resist Attack

Smart Grid technologies better identify and respond to man-made or natural disruptions. Real-time information enables grid operators to isolate affected areas and redirect power flows around damaged facilities.

One of the most important issues of resisting attack is the smart monitoring of power grids, which is the basis of control and management of Smart Grids to avoid or mitigate the system-wide disruptions like blackouts. New technology as well as enhancement of existing state monitoring technology is needed to achieve the goals of a Smart Grid.

4.4 High Quality Power

Among the goals of Smart Grid technologies are reducing system downtime and preventing losses to productivity and the reduced quality of life associated with energy system interruptions.

Using the additional intelligence provided by sensors and software designed to react instantaneously to imbalances, Smart Grid technology can also help to mitigate any degradation of system power quality that may be caused by the intermittent operation of Distributed Resources such as wind and solar. Relay based dynamic reconfiguration schemes incorporate the projected voltage profile when restoring power following a distribution fault.

4.5 Accommodate Generation Options

As Smart Grids continue to support traditional power loads, they also seamlessly interconnect fuel cells, renewables, microturbines, and other distributed generation technologies at local and regional levels. Integration of small-scale, localized, or on-site power generation allows residential, commercial, and industrial customers to self-generate and sell excess power to the grid with minimal technical or regulatory barriers. Integration of generation options, both localized and traditionally centralized, improves reliability and power quality, may reduce electricity costs, and offers more customer choice.

4.6 Enable Electricity Market

Significant increases in bulk transmission capacity will require improvements in transmission grid management. Such improvements are aimed at creating an open marketplace where alternative energy sources from geographically distant locations can easily be sold to customers wherever they are located.

Intelligence in distribution grids will enable small producers to generate and sell electricity at the local level using alternative sources such as rooftop-mounted photo voltaic panels, small-scale wind turbines, and micro hydro generators.

4.7 Optimize Assets

A Smart Grid can optimize capital assets while minimizing operations and maintenance costs. Optimized power flows reduce waste and maximize use of lowest-cost generation resources. Harmonizing local distribution with interregional energy flows and transmission traffic improves use of existing grid assets and reduces grid congestion and bottlenecks, which can ultimately produce consumer savings.

4.8 Enable High Penetration of Intermittent Generation Sources

Political initiatives to address climate change, environmental concerns, and economic drivers are increasing the amount of renewable energy resources. These are often intermittent in nature. Smart Grid technologies will help to enable power systems to accommodate larger amounts of such energy resources since they enable both the suppliers and consumers to compensate for such intermittency.

5 SMART GRID FEATURES

Existing and planned implementations of Smart Grids provide a wide range of features to perform the required functions.

5.1 Load Adjustment

The total load connected to the power grid can vary significantly over time. A Smart Grid may warn individual customers to reduce the load temporarily (to allow time to start up a larger generator) or continuously (in the case of limited resources). Using mathematical prediction algorithms, it is possible to predict how many standby generators need to be used to restore or maintain a stable power system for specific system contingencies. In the traditional grid, the maintenance of a stable local grid for a specific failure can only be achieved at the cost of more standby generators. In a Smart Grid, the load reduction by even a small portion of the clients may eliminate the problem.

5.2 Demand Response Support

Demand response support allows generators and loads to interact in an automated fashion in real time, coordinating demand to flatten load spikes. Eliminating the fraction of demand that occurs in these spikes eliminates the cost of adding reserve generators, cuts wear and tear and extends the life of equipment, and allows users to cut their energy bills by telling low priority devices to use energy only when it is cheapest [6].

5.3 Greater Resilience to Loading

Although multiple routes are touted as a feature of the Smart Grid, the old grid also featured multiple routes. Initial power lines in the grid were built using a radial model. Later, connectivity was achieved via multiple routes, referred to as a network structure. However, this created a new problem: if the current flow or related effects across the network exceed the limits of any particular network element, that network element could fail, and the current would be shunted to other network elements, which eventually may fail also, causing cascading outages. Historically, techniques to prevent this have included load shedding by rolling blackout or voltage reduction. Smart Grid techniques can be used to prevent these cascading outages using intelligent reconfiguration following an element failure.

5.4 Decentralization of Power Generation

Another element of fault tolerance of Smart Grids is decentralized power generation. Distributed generation allows individual consumers to generate power onsite, using whatever generation method they find appropriate. This allows individual consumers to tailor their generation directly to their load, reducing or eliminating the impact from grid power failures. Classic grids were designed for one-way flow of electricity, but if a local sub-network generates more power than it is consuming, the reverse flow can raise safety and reliability issues. A Smart Grid can help to manage these situations.

5.5 Price Signaling to Consumers

In many countries, including Belgium, the Netherlands, and the UK, the electric utilities have installed double tariff electricity meters in many homes to encourage people to use their electric power during night time or weekends, when the overall demand from industry is very low. During off-peak time the price is reduced significantly, primarily for heating storage radiators or heat pumps with a high thermal mass, and also for domestic appliances. This idea will be further explored in a Smart Grid, where the price could be changing in seconds and electric equipment is given a methodology to respond to those price signals.

6 SMART GRID TECHNOLOGY

A large percentage of Smart Grid technologies are already used in other applications such as manufacturing and telecommunications, and are now being adapted for use in grid operations.

6.1 Integrated Communications

Some communications are up to date, but are not uniform because they have been developed in an incremental fashion and not fully integrated. In most cases, data is being collected via modem rather than direct network connection. Areas for improvement include: substation automation, demand response, distribution automation, supervisory control and data acquisition (SCADA), energy management systems, wireless mesh networks and associated technologies, power-line carrier communications, and fiber-optics. Integrated communications will allow for real-time control, as well as information and data exchange, to optimize system reliability, asset utilization, and security.

6.2 Sensing and Measurement

Core duties are evaluating congestion and grid stability, monitoring equipment health, energy theft prevention, and control strategies support. Technologies include: advanced microprocessor meters (smart meter) and meter reading equipment, wide-area monitoring systems, dynamic line rating (typically based on online readings by Distributed temperature sensing combined with Real time thermal rating (RTTR) systems), electromagnetic signature measurement/analysis, time-of-use and real-time pricing tools, advanced switches and cables, backscatter radio technology, and protective IEDs.

6.3 Smart Meters

A Smart Grid replaces analog mechanical meters with digital meters that record usage in real time. Smart meters are similar to Advanced Metering Infrastructure meters and provide a communication path extending from generation plants to electrical outlets (smart socket) and other Smart Grid-enabled devices. By customer option, such devices (for example, air conditioning or certain appliances) can shut down during times of peak demand.

6.4 Phasor Measurement Units (PMU)

High speed sensors called PMUs distributed throughout a network (as stand-alone units or as a function in relays or meters) can be used to monitor power quality and in some cases respond automatically. Phasors are representations of the waveforms of alternating voltage and current,. In the 1980s, it was realized that the clock pulses from global positioning system (GPS) satellites could be used for very precise time measurements in the grid. With large numbers of PMUs and the ability to compare angles from readings everywhere on the grid, research suggests that automated systems will be able to revolutionize the management of power systems by responding to system conditions in a rapid, dynamic fashion (5).

A Wide-Area Measurement System (WAMS) is a network of PMUs that can provide real-time monitoring on a regional and national scale. Many experts in the power systems engineering community believe that the Northeast blackout of 2003 would have been contained to a much smaller area if a wide area phasor measurement network was in place. (6)

6.5 Advanced Components

Innovations in superconductivity, fault tolerance, storage, power electronics, and diagnostics components are changing fundamental abilities and characteristics of grids. Technologies within these broad R&D categories include: flexible alternating current transmission system devices, high voltage direct current, first and second generation superconducting wire, high temperature superconducting cable, distributed energy generation and storage devices, composite conductors, and “intelligent” appliances.

6.6 Advanced Control

Power system automation enables rapid diagnosis of and precise solutions to specific grid disruptions or outages. Some advanced control methods include: distributed intelligent agents (control systems), analytical tools (software algorithms and high-speed computers), and operational applications (SCADA, substation automation, demand response, etc). Using artificial intelligence programming techniques, Fujian power grid in China created a wide area protection system that is rapidly able to accurately calculate a control strategy and execute it (7). The Voltage Stability Monitoring & Control (VSMC) software uses a sensitivity-based successive linear programming method to reliably determine the optimal control solution (8).

6.7 Improved Interfaces and Decision Support

The Smart Grid will require information systems to reduce complexity so that operators and managers have tools to effectively and efficiently operate a grid with an increasing number of variables. Technologies will include visualization techniques that reduce large quantities of data into easily understood visual formats, software systems that provide multiple options when systems operator actions are required, and simulators for operational training and "what-if" analysis.

6.8 Standards and Groups

There is a growing trend towards the use of TCP/IP technology as a common communication platform for Smart Meter applications, so that utilities can deploy multiple communication systems, while using IP technology as a common management platform. (9) (10).

The following is a list of some of the efforts by international standard organizations to produce standards aimed to assist in the design of Smart Grid applications:

6.8.1 IEC TC 57

IEC TC57 has created a family of international standards that can be used as part of the Smart Grid. These standards include:

- IEC61850 which is an architecture for substation automation
- IEC 61970/61968 — the Common Information Model (CIM) which provides common semantics to be used for turning data into information.

6.8.2 MultiSpeak

MultiSpeak has created a specification that supports distribution functionality of the Smart Grid. It has a robust set of integration definitions that supports nearly all of the software interfaces necessary for a distribution utility or for the distribution portion of a vertically integrated utility. Its integration is defined using extensible markup language (XML) and web services.

6.8.3 IEEE

- The IEEE has created a standard to support synchrophasors — C37.118.
- IEEE P2030 is an IEEE project developing a "Draft Guide for Smart Grid Interoperability of Energy Technology and Information Technology Operation with the Electric Power System (EPS), and End-Use Applications and Loads" (11) (12)

6.8.4 UCA International Users Group (UCAIug)

A User Group that discusses and supports real world experience of the standards used in Smart Grids is the UCA International User Group.

7 INDUSTRY SECTORS INVOLVED IN THE SMART GRID

The Smart Grid as the convergence of three industries/sectors: (13)

- Electric Power (Energy)
- Telecommunications Infrastructure
- IT (Information Technology)

Each industry's expertise is needed to provide one of three high-level layers of a complete and end-to-end Smart Grid and/or Intelligent Utility Network:

- The Physical Power Layer (transmission and distribution)
- The Data Transport and Control Layer (communications and control)
- The Application Layer (applications and services)

In order to have what is known as a true end-to-end Smart Grid, that is, to be able to run applications back and forth from the utility to the consumer, an end-to-end communication network is needed. While utilities have for years had their own local area networks (LAN) and wide area networks (WAN) to transport data both within the utility's headquarters and to and from the substation, the missing link in communications has been the network that could bridge the utility to the end-user, and vice versa.

The emergence and continued development of an end-to-end communications layer is required for advancing the Smart Grid, as new applications will both improve and optimize the generation, delivery and consumption of electricity. Further, on a true Smart Grid, with distributed resources, it is not only data that will move in two directions, but power itself. A more intelligent grid greatly facilitates the introduction of distributed power sources, which include wind farms and solar power generation plants connected to the power grid at medium or high voltage levels, and high-penetration photovoltaic solar panels, micro-wind turbines, and stationary fuel cells connected at low voltage levels.

This missing link in communications – an intelligent Field Area Network (FAN) – is now for the first time being built-out as a result of wide-scale advanced metering infrastructure (AMI) deployments that replace old fashioned mechanical meters with advanced digital meters, or "smart meters." Smart meters – physical meters that allow for two-way communication – necessitate a communications infrastructure to transport the data which they generate. Many countries around the world have ambitious smart meter rollout projects underway.
It is helpful to think of AMI as having two layers:

1. The transport layer (the communications network that sends data back and forth in between the smart meter and the WAN, via the intelligent FAN).
2. The application layer (running any metering-specific "app" that a utility deems worthwhile).

Effectively the AMI transport layer/communication network provides the missing link in the end-to-end communication network infrastructure, and as such is synonymous with the familiar terms FAN or "last mile" (from the telecom industry) as the final leg delivering connectivity from a utility to a customer. This end-to-end connectivity is certain to bring change to the industry and the adoption of communications and information technologies, and will open the door for a wide range of new advanced applications and technologies.

Further, the AMI/FAN not only forms the bridge back to the utility's operations and control center, but also to the network inside the home or building, referred to as the home area network (HAN). So ultimately, end-to-end communication will extend from the power plant/utility end of the grid all the way to specific appliances inside buildings (lighting systems, refrigerators, dishwashers, HVACs, etc.), giving both utilities and consumers much more granular insight and control over energy generation and consumption decisions. This is especially important, as this further connectivity allows for applications such as demand response (where utility operators can turn down end-user appliances to curb peak power demands) to perform with much greater precision and reliability.

Each of the applications highlighted in this document is ground-breaking in its own respect, as each presents new ways to improve either generation, transmission, distribution and/or consumption of electricity (or some combination of all four). (13) As proof of this assertion, new industries are already popping up around each of the applications listed in Figure 2.

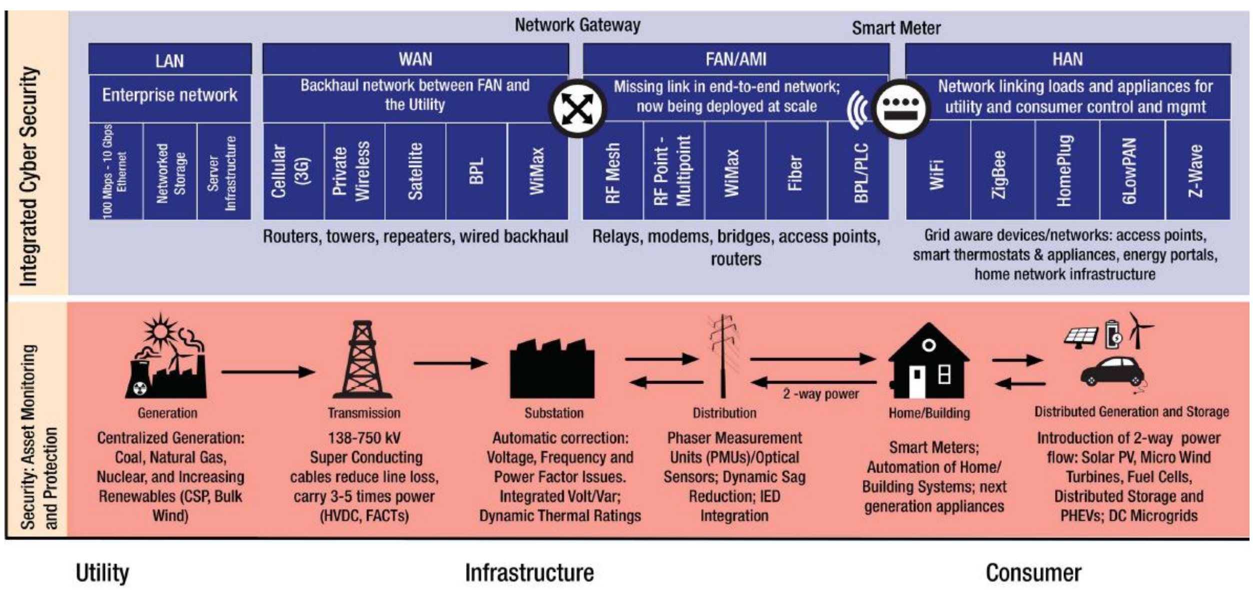

Figure 2. Detailed Smart Grid Market Taxonomy

APPLICATION/MARKET SEGMENT	2010	2015	2020
AMI	The first large-scale deployments underway	Substantial and growing market penetration and network Infrastructure build-out	Significant and wide-ranging Implementation
Demand Response	Limited reach (mainly commercial and industrial customers)	Substantial market penetration for residential, commercial and Industrial	Commonplace with a wide variety of end-user service programs
Grid Optimization	A handful of utilities beginning distribution/ substation automation projects	Sensor technology embedded on the distribution network; automation becoming routine	Dynamic Sensing everywhere; Grid becomes an Intelligent Utility Network
Distributed Generation Integration	Nascent	Maturing, but still a small % of power generation	Approaching Mainstream More substantial presence;
Energy Storage	A few pilots among progressive utilities	Expected technology advancements and increased Distributed Generation penetration will boost storage's role	Vital role in supporting Distributed Generation
PHEV	N/A	Smart Charging	V2G (vehicle-to-grid)
Consumer Energy Management Systems	Successful pilots continue to highlight consumer demand	Gaining traction as "set-it-and-forget" technologies make energy management simple to use and cost-effective	Routine, Web-based

Source: GTM Research

Figure 3. Smart Grid Application & Market Sector Time Line

The deployment of these new technologies and applications has started. AMI deployments are currently setting off a great deal of activity from generation to consumption. On the utility end of the power grid, advanced control systems not only add new systems and capabilities, but also properly integrate all business systems across the enterprise. Home area networks will change the way in which consumers relate to their energy usage. In between, there will many applications and technologies stacked on top of each other that will collectively push towards the true vision of a Smart Grid.

8 SMART GRID SEGMENTS AND APPLICATIONS

In this section, the leading Smart Grid segments and applications from the taxonomy shown in Figure 2 are detailed.

8.1 Advance Metering Infrastructure (AMI)

Advanced metering infrastructure (AMI) is seen as a transformative application since the AMI/FAN communication network necessary to run advanced metering applications can also be used to transport data for all kinds of other emerging Smart Grid applications. Grid Optimization is one example of a non metering market segment that is enormously enhanced by having end-to-end communications, as the utility now gains instantaneous information about grid performance and events such as outages and faults (as opposed to having to wait for a phone call from upset customers)).

Demand response (DR) and the integration of distributed resources are other examples of applications that can "ramp up" more quickly once the communication network is in place. While AMI applications themselves are metering specific, concerned with making the meter data collection process less labor intensive, and less costly (as utilities will no longer send out field workers to physically read the meters), these utility-scale AMI deployments, which are now underway across the globe, are truly transformative. A great number of additional benefits and market segments will continue be discovered and deployed in an effort to not only improve system-wide reliability, asset utilization and protection, but also to reduce fossil-based electric generation requirements and their related carbon emissions.

8.2 Demand Response

Demand Response (DR) is a relatively simple concept to understand. Utilities provide incentives to electricity customers to reduce their consumption at critical, "peak" times on demand.

Contracts, made in advance, specifically determine both how and when the utility (or an acting third-party intermediary) can reduce an end user's load. The utility benefits by not having to resort to more expensive (and less environmentally friendly) peaking power plants, and consumers benefit by earning income by reducing their monthly energy bills.

To date, most demand response efforts in North America have been coordinated with the larger users of energy – commercial and industrial users. Historically, rudimentary communications – often a phone call – are how operators notified participating customers to turn down the power. Smart Grid communication networks improve the way operators reach consumers. Further, residential users (that have smart meters installed) will increasingly have the option to enroll in DR programs, giving demand response "reach" to a substantial portion of the overall system.

Demand response is the most cost effective, faster, cleaner and more reliable solution than natural-gas-fired peaking plants (the leading response to peak power generation needs) to address the need for additional energy sources to meet the current energy demand. By shifting the usage of energy to off-peak hours or by allowing the utility to have control over the load, this helps reduce the peak power demand, and therefore, reduce the need to increase the overall system capacity to meet the traditional demand.

8.3 Grid Optimization

Grid optimization entails a wide array of potential advances that will give utilities and grid operators digital control of the power delivery network. The addition of sensor technology, communications infrastructure and IT will help optimize the performance of grid in real-time, and improve reliability, efficiency and security. Grid operators will gain improved situational awareness as fundamental system-wide visibility and analytics will now be in place. While AMI deployments lay the foundation for utilities having control of millions of end user devices, real-time command and control of higher level grid devices is of equal, if not greater, value in the current push for overall grid efficiency.

8.4 Distributed Generation

The Smart Grid will be instrumental in facilitating and integrating renewable sources of energy such as wind and solar energy. Smart Grid promises to make these green technologies ubiquitous in our lives.

While great technological advances have occurred – improved conversion efficiency, scalability, cost reductions and so forth – the issue is no longer whether these technologies are ready, but rather, whether or not modern societies have the infrastructures in place capable of supporting the introduction of renewable energy technologies at mass scale. The Smart Grid aims to tackle the scale-management problem that arises when thousands, if not millions of new devices are added to a system.

8.5 Energy Storage

Energy storage is increasingly perceived as both a viable and necessary component of any future, intelligent electric grid. The leading visions of how a Smart Grid could operate usually focus on distributed storage options, rather than bulk storage. While both forms of storage will be welcomed on a grid that historically has had effectively zero storage, distributed energy storage assets – located near the consumption end of the grid – will provide localized power where it is most needed, and decrease the need to build new power plants and transmission lines. The most discussed benefit of energy storage is that it helps solve the intermittency problem associated with renewable energy, and as such, will help "green" sources of energy scale faster and reach a wider market penetration. While it's true that energy storage will give a huge boost to the potential of renewable energy – and has rightly been labeled the missing link for renewables – significant storage capacity solves the even bigger issue of capturing the massive amounts of capacity generated that otherwise would typically go unused.

8.6 Electric Vehicles (EV) and Plug-In Hybrid Electric Vehicles (PHEVs)

One of the most discussed and anticipated "applications" of Smart Grid is the introduction of the EV / PHEV). An EV/ PHEV's larger battery will allow for both the possibility of storing electricity, which might otherwise go unused (ideally from renewable, intermittent sources), and of feeding stored energy back into the electric grid in periods of high demand. In this way,EV/ PHEVs could serve as a back-up source of power for the electric grid.

EV/PHEVs are being marketed and sold by virtually every major automobile manufacturer in the world,and utilities are now scrambling to ready themselves for what could be a truly disruptive technology.

The two leading challenges will be (1) smart charging – how to smooth the charging of millions of EV/ PHEVs in order to prevent accidental peaks and (2) how to draw power from these batteries in a way that doesn't alter the expected life of the battery or leave the vehicles undercharged when their drivers turn them on. The concept of vehicle to grid (V2G) – pulling power from car batteries to feed peak demand- properly fits into the energy storage market. Therefore, new systems and analytics will be needed to accommodate this growth.

8.7 Advanced Utility Controls Systems

An Advanced Utility Controls System refers to the upgrade and continued integration of various mission-critical systems, applications and back-end technology infrastructure necessary to support a utility's monitoring, control and optimization of the grid. In order to leverage the full potential of AMI deployments (and the end-to-end communication networks now in place), utilities will need to develop enterprise wide systems that are capable of sharing data across applications and systems. While historically utilities' systems have been far from integrated, the realization of a Smart Grid will depend on a utility-wide integration of systems (and business processes) which allow for real time visibility and decision support. For example, at the system load level, before a utility decides to draw power from distributed storage assets to mitigate peak energy demand, the utility would do well to consider if it would make more financial (and environmental) sense to issue a demand response call instead. Or for that matter, a utility may weigh the cost/benefits of calling upon any and all grid connected generation sources for a particular scenario.

8.8 Smart Homes and Networks

By adding intelligence and networking capabilities to appliances (such as thermostats, heating, lighting and A/C systems) located inside buildings and residences, both the utility and consumer stand to benefit. Homeowners will be able to monitor their energy consumption and reduce their utility bills with very little effort, as well as financially gain from incentives provided by the utility for energy conservation.

Meanwhile, utilities that now have an extension of Smart Grid into the house, can better manage peak demand beyond simple demand response initiatives. The extension of smart metering intelligence into the home/building itself (connecting the meters to "load centers") is a radical advancement for the power grid.

9 SMART GRID PROJECTS

Developing a list of relevant Smart Grid projects requires that the meaning of a Smart Grid be clearly defined. In the previous sections of this report, we attempted to provide one possible definition of the Smart Grid which will be the foundation of the concepts and ideas included in subsequent sections.

The following is a list of possible Utility Smart Grid Projects, which are generally complex with many cost-benefit factors and frequently where multiple Smart Grid technologies and project types come together. Smart Grid projects could consist of:

- Retrofits to transmission apparatus with Smart Grid capabilities
- Transmission monitoring, control, and optimization including sensors, communications, and computer systems and software
- Distribution monitoring, control, and optimization including sensors, communications,and computer systems and software
- Smart Grid technologies focused on renewables facilitation
- Advanced Metering including advanced meters, communications infrastructure, and computer systems and software
- Communications infrastructure to support Smart Grid including distribution automation and advanced metering
- Microgrids capable of high reliability/resiliency and islanded operation
- Integration of Distribution Automation (DA), Feeder Automation (FA), Advanced Metering Initiatives (AMI), and microgrid technologies
- Technologies to assist in the efficient integration of plug-in hybrid vehicles
- Consumer integration into energy markets and grid operations
- Cyber Security projects

The following sections (9.1-9.11) provide a list of possible Smart Grid Projects:

9.1 Retrofit of Transmission Apparatus with Smart Grid Capabilities:

- Flexible AC transmission technologies
- High-efficiency technologies (e.g., low-loss or superconducting technologies)
- High-speed switchgear
- New voltage transient suppression technologies
- Environmentally-friendly technologies
    - Lower profile transmission towers; Oil-free or gas-free apparatus
    - New technologies targeted at renewables integration (e.g., novel undersea cables for offshore wind)
    - Storage applied as a resource.

9.2 Transmission Monitoring, Control, and Optimization:

- Sensors
- Communications
- Automation systems
- Asset-condition monitoring systems
- Planning and control room applications, including computer systems and software.

9.3 Distribution Monitoring, Control, and Optimization:

- Sensors
- Automation systems
- Asset-condition monitoring systems
- Planning and control room applications, including computer systems and software including: feeder and substation automation with particular provisions for reducing peak and off-peak energy consumption
- Integrating high renewable levels
- Integrating consumer-side resources and demand response
- Improving reliability
- Reducing losses
- Improving resiliency against major disturbances – physical and cyber, natural, accidental, and deliberate
- Apparatus with new controllability, efficiency, or environmental-direct benefits.

9.4 Smart Grid Technologies Focused on Renewables Facilitation:

- There are a number of technology "gaps" associated with support for high levels of renewable resources ranging from apparatus (inverters capable of providing voltage VAR support, governor response, and power system stabilization) to protection/automation systems (specific wide-area protection schemes):
    - Feeder and station protection and automation systems developed for high local renewables penetration
    - Protection systems developed for high behind the meter or distributed renewables on distribution circuits
    - Analytic applications (forecasting, scheduling, and optimization tools which are developed for the high levels of uncertainty associated with some renewable portfolio projections).

9.5 Advanced Metering:

- Two-way metering capable of a variety of functionality including real-time pricing
- Remote connect/disconnect
- Integration of electric vehicles (EVs) and home area networks (HAN) at some level
- Power quality sensing and communications

9.6 Communications Infrastructure Projects

- Associated with enabling utility-wide coverage for distribution automation, advanced metering, distributed generation, storage, and other resources.

- Distribution communication networks for Smart Grid capabilities:
  - Facilitating a network dedicated to the increased use of sensors installed throughout the distribution grid and other real-time, automated, interactive technologies required by the Smart Grid
  - For communications concerning grid operations and status, distribution automation, integration of renewable, Advanced Metering and microgrids.

9.7 Microgrids Capable of High Reliability/Resiliency and Islanded Operation:

Advanced microgrids integrated with distributed generation and storage, bridge distribution systems, and consumer technologies.

9.8 Integration of Distribution Automation (DA), Feeder Automation (FA), Advanced Metering Initiatives (AMI), and Microgrid Technologies:

Microgrids that are integrated operationally with utility Smart Grid systems.

9.9 Technologies to Assist in the Efficient Integration of Plug-In Hybrid Vehicles

Charging control, communications, computer systems and software, and distribution automation associated with PHEV integration with grid and market operations.

9.10 Consumer Integration Into Energy Markets and Grid Operations:

Systems communicate market information to customers and enable them to make decisions which impact markets, as well as facilitate integration of grid operations with consumer decision making. Systems for integrating EVs with Smart Grid fall under this category.

9.11 Cyber Security Projects:

Systems involving IT technologies, communications, and field Smart Grid components that are specifically targeted at achieving system compliance with cyber security standards.

10 ACTIVE NETWORK MANAGEMENT

Active network management (ANM) is a Smart Grid concept that is generally intended to dynamically optimize system performance by automatically reconfiguring a network as system conditions change. Some objectives of ANM are to economize power delivery, minimize system losses, maximize the contribution of available renewable energy, prevent undesirable overloading of conventional and DR sources, as well as network segments, and regulate system voltage. While ANM may take many forms, all of these application principles can benefit from the measurements and status provided by relays and controls associated with substation devices, DR, and interim-feeder fault-interrupters and sectionalizers.

One ANM application that has been successfully deployed restricts the amount of DR renewable-energy that can be connected under varying system conditions. This solution was developed as a result of DR renewable-energy installations outpacing a medium-voltage (MV) network's ability to accommodate this increased generation. This ANM approach uses deterministic (real-time) feeder loading data, the status of network interconnections, and existing and potential DR contributions, to individually regulate the output of every connected DR. Additionally, DR contractual obligations and the availability of renewable energy are also factors in regulating DR output.

While this present implementation already relies on relay measurement and status data, increased feeder segmentation is being considered to further improve the network's ability to accommodate more renewable-energy. As these additional feeder sectionalizers will be equipped with relays, their data will become key components in enhancing system performance.

11 IMPACT OF PROTECTION ON SMART GRID FUNCTIONS

11.1 Dynamic Loading of Transformers, Cables and Transmission Lines

Wind farms tend to be located at the extremes of the system where lines may not be rated to carry the full output of the wind farm in all circumstances. Often a line has been designed originally to supply a relatively small load, and the installation of new wind generation may cause a large reverse power flow, and cause the standard winter and summer line ratings to be exceeded. The worst case in this respect is with maximum wind generation and minimum local load.

Rather than applying fixed summer and winter line ratings, load management based on a dynamically derived line rating can be adopted. Use of a dynamic thermal rating or a real time thermal rating of transmission lines can avoid unnecessary and costly network reinforcement and add extra capacity to the DG project. Some methods that could be used to determine the real time rating using protection relays are described below.

11.1.1 Dynamic Line Rating (DLR) Based on Local Measurements

The relay design described below is based on an existing multi-function relay product. The dynamic line rating protection has been added as an enhancement to the existing functions such as overcurrent and earth fault protection.

A current loop interface (0-1mA, 0-10mA, 0-20mA or 4-20mA) is an analogue electrical transmission standard for instruments and transducers, and is employed for communications between the weather station and the relay. The relay allows the user to select the type and the current loop input channels to be used for the wind speed, wind direction, solar radiation and the ambient temperature monitoring as required. The results are fed into the CIGRE 207 or IEEE 738 standard algorithms which implement the dynamic line rating calculations to calculate the line ampacity. The ampacity of an overhead line is the maximum current that a circuit can carry without exceeding its sag temperature or the annealing onset temperature of the conductor, whichever is lower.

Three phase currents are measured. The maximum phase current magnitude is selected as the relaying quantity for the alarm and tripping criteria. The current magnitudes, the sensor measurements, together with the calculated ampacity, are available from the relay as measured quantities. Figure 4 shows the details of the inputs to the relay.

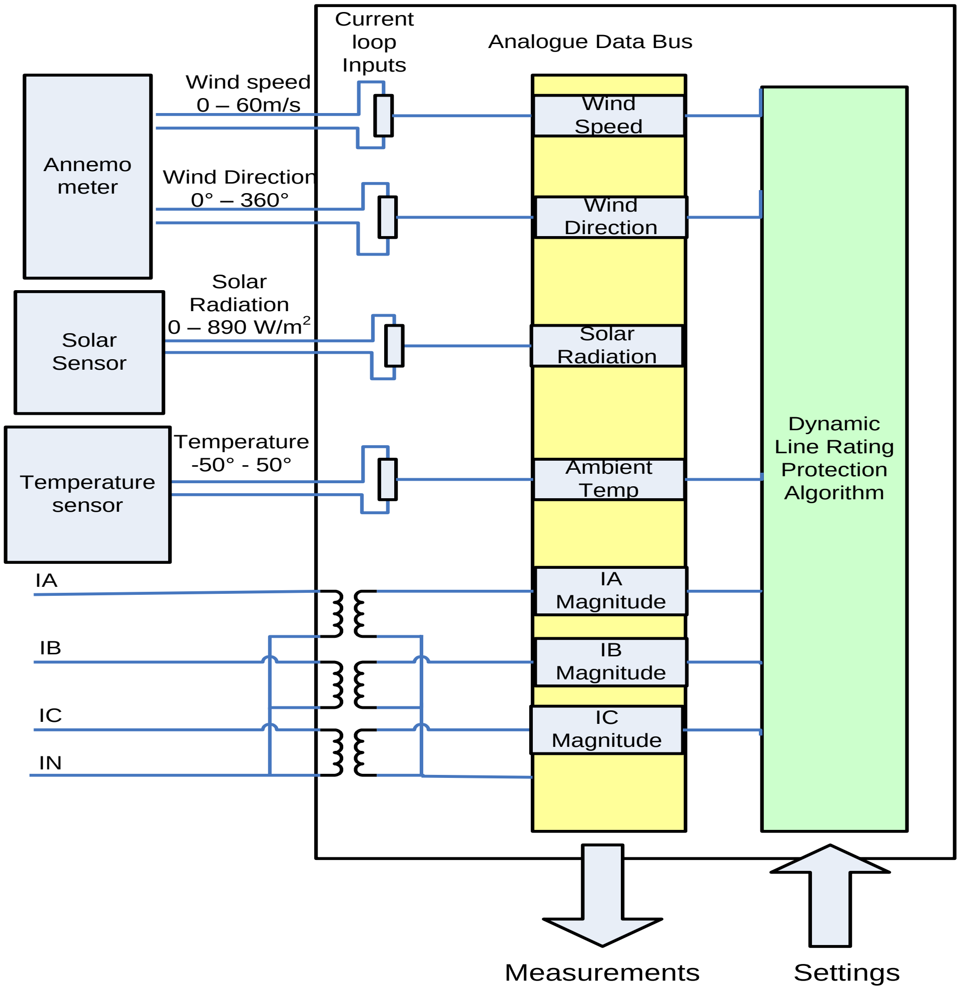

Figure 4. Inputs to the dynamic line rating protection relay

Six DLR stages of control / protection are available; each consists of its own threshold level and time delay settings which operate when the measured line current reaches a certain percentage of the dynamically calculated ampacity. These six stages can provide control commands to the distributed generators to hold or reduce their power output. If the control actions are not successful at reducing the conductor currents (e.g. due to a communications failure), the protection relay can operate as a backup mechanism and use one of the protection stages to trip the distributed generation or line after a time delay.

In configuring the relay, apart from setting the DLR thresholds and time delays, it is also necessary to enter a range of conductor data parameters which are required for the heating and cooling calculations. To assist the user, the relay stores the relevant parameters of various types of industry-standard conductors. For other conductor types, settings are available for the user to enter the relevant parameters directly.

11.1.2 Dynamic Line Rating (DLR) Based on Synchrophasors

The emerging worldwide scenario of Smart Grids and related applications also involves system monitoring. IEDs with integral synchrophasor measurements have been available for many years now, and contribute to more flexible monitoring in the electrical network.

Phasor measurement Units (PMUs) installed at the ends of a feeder, for instance, and communicating to a phasor data concentrator (PDC), can also be used for line thermal monitoring applications by determining the mean line temperature from the phasor measurements of voltage and current at both ends of the line. The PMUs can calculate the actual impedance and shunt admittance of a line and extract the line resistance. Based on the known properties of the conductor material, the actual average temperature can be determined. This temperature includes the environmental conditions such as wind speed, solar radiation and line current. Consequently, this data offers much more information on the loadability of the line than the line current alone can provide. The line thermal monitoring can serve as an early warning system in case of potential overloads where the operators gain information to initiate corrective actions. Such real-time condition monitoring enables utilities to make full use of the power transfer capacity of the line without violating the thermal design limits.

11.2 Power Transformer Asset Management

Due to the high capital cost of transformers, and the need for their in-service availability to be as high as possible to avoid constraining load flows demanded on the network, protection is no-longer the only concern. The demand on the network increases as cities expand, consumers' lifestyle expectations increase, and electric vehicle recharging loads become more prevalent. This increases the focus on knowing the real-time health of transformers to be able to schedule condition-based maintenance. Maintenance or reconditioning at a time of the asset-owner's choosing is far more preferable than a forced unplanned outage due to failure.
Over the past few years many stand-alone devices have been developed for transformer condition monitoring. However, modern protection relays can offer an economic solution for condition monitoring, as well as provide the required protection functionality and integration into the control system.

This section provides an overview of techniques commonly available in modern numerical transformer protection relays, which can extend to asset management of the protected transformer.

11.2.1 Transformer Relay Design for Condition Monitoring

This section describes the design of a typical comprehensive transformer protection relay for protecting two and three winding transformers (including autotransformers), with multiple sets of three-phase CT voltage inputs. The relay includes protection against transformer overload, through-fault and overexcitation, as well as standard protection functions such as differential, overcurrent and earth fault etc for internal faults.

The relay includes a number of measurable indicators of transformer serviceability monitoring the electrical load; top-oil, hottest-spot and ambient temperatures; fault history; and measured excitation. Utilities that use these indicators can make intelligent profit/risk decisions and plan optimal transformer loading and maintenance.

The protection relay includes many of the common transformer condition monitoring features required, such as listed below:

- Transformer top oil and hot spot temperature calculation--takes into account the ambient temperature, load variations and oil thermal parameters, based on IEEE Standard C57.91-1995 .
- Transformer loss of life calculation, based on IEEE Standard C57.91-1995 --provides data on accumulated loss of life, rate of loss of life, aging acceleration factor and residual life hours.
- Transformer through fault monitoring based on I^2t calculation of the maximum fault current and fault duration per phase.
- Temperature monitoring, for example, of top oil, bottom oil, cooler inlet/outlet oil, tap changer compartment oil and winding hotspot temperature via the relays ten RTD inputs or four current loop inputs (CLIO - current loop inputs and outputs).
- Monitoring and alarming of other sensor quantities, such as tap changer position, oil level, bushing oil pressure via the relay current loop inputs.
- Load and short circuit current and system voltages monitoring via the protection relay current and voltage transformer inputs. The relay can also provide CT and VT supervision of these inputs.

The relay may include flexible industry standard communication options to interface the relay protection and condition monitoring functions to the customer's SCADA system. For example the relay may support a number of standard protocols such as MODBUS, IEC 60870-5-103, DNP 3.0 and IEC 61850 and include communication options such as RS485, fiber optic, Ethernet or redundant Ethernet plus a front communications port for local access.

The relay may also includes programmable LEDs for user friendly local indication and programmable scheme logic for easy scheme customization. Sequence of event and disturbance recording features are also included that can help diagnose faults and alarms.

As described above, the relay may include transducer (current loop) inputs with flexible ranges of 0-1mA, 0-10mA, 0-20mA or 4-20mA, which can be used with a number of external monitoring sensors to indicate temperature, oil level, etc. Associated with each input there are two time delayed protection stages, one for alarm and one for trip. Each stage can be set for 'Over' or 'Under' operation. Current loop outputs are also provided with ranges of 0-1mA, 0-10mA, 0-20mA or 4-20mA, which can alleviate the need for separate transducers. These may be used to feed standard moving coil ammeters for analog indication of certain measured quantities or for input to SCADA using an existing analog RTU. Up to 24 digital inputs are available to provide status information from external devices such as CBs or external sensors, and up to 24 output contacts are available to provide alarm and trip outputs. Figure 5 depicts functional block diagram of a typical relay.

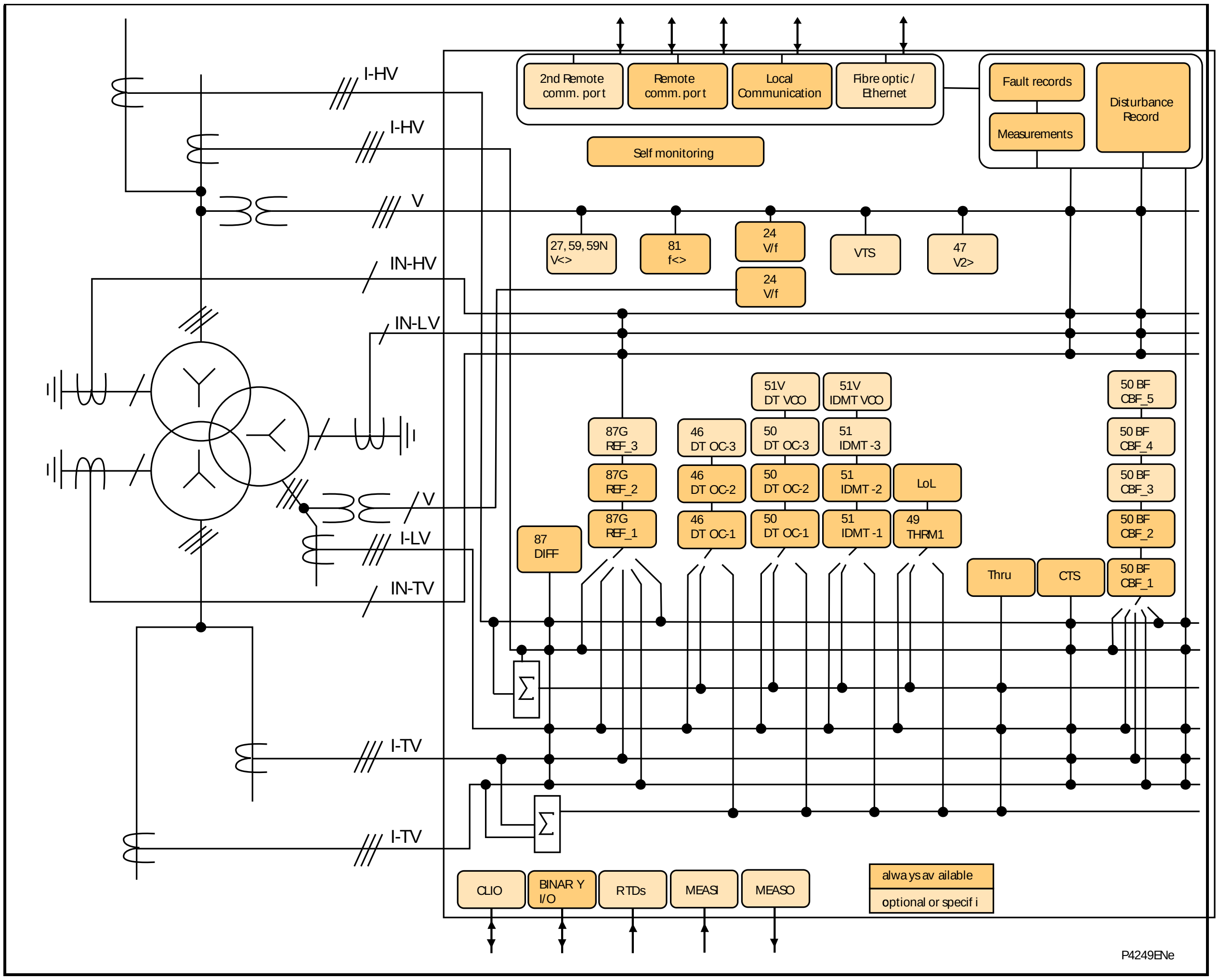

Figure 5. Transformer protection and condition monitoring functional diagram

11.2.2 Loss of Life Monitoring

Ageing of transformer insulation is a time-dependent function of temperature, moisture, and oxygen content. The moisture and oxygen contributions to insulation deterioration are minimised due to the preservation systems employed in the design of most modern transformers. Therefore, temperature is the key parameter in insulation ageing. Frequent excesses of overloading will shorten the life-expectancy of the transformer, due to the elevated winding temperatures.

Insulation deterioration is not uniform, and will be more pronounced at hot-spots within the transformer tank. Therefore, an asset management system intended to model the rate of deterioration and current estimated state of the insulation may do so based on simulated real-time hot spot temperature algorithms unless the transformer has been built with a direct hot spot measuring system. These models may take ambient temperature, top-oil temperature, load current flowing, the status of oil pumps (pumping or not), and the status of radiator fans (forced cooling or not) as inputs.

Modern IEDs provide such a loss of life monitoring facility, according to the thermal model defined in IEEE Standard C57.91. The algorithm determines the current rate of life loss, and uses that to indicate the remaining years or hours until critical insulation health statuses are likely to be reached. Such criticalities will relate typically to known percentage degradations in the tensile strength of the insulation, degradation in the degree of polymerisation, and other life-loss factors. The asset owner can be alerted in advance that an outage will be required for reconditioning or rewinding, such that investment budgeting can be made years and months ahead of time. This relay based model does not replace a Dissolved Gas Analysis (DGA) system but can supplement it.

11.2.3 Through-Fault Monitoring

Loss of life monitoring serves to track the deterioration caused by long term, repeated overloading. However, it is not the proper technique to monitor short-term heavy fault currents which flow through the transformer, out to an external fault on the downstream power system. Through faults are a major cause of transformer damage and failure, as they stress the insulation and mechanical integrity – such as the bracing of the windings.

A specific through-fault monitor is recommended to monitor currents which are due to external faults passing through, and so may range from 3.5 to tens of times the rated current of the transformer. Modern IEDs perform an I^2t calculation when the through current exceeds a user-set threshold, such that the heating effect of the square of the maximum phase current, and the duration of the fault event are calculated. Calculation results are added to cumulative values, and monitored so that users can schedule transformer maintenance or identify a need for system reinforcement.

12 CYCLIC LOAD SHEDDING USING PROGRAMMABLE LOGIC

12.1 Introduction

Introduction of microprocessors in the field of Protection & Control has brought forth a revolution in the way solutions are realised. Today, numerical relays have evolved to provide a host of functions in addition to the core protection function. This section shows the advantages of one such function available in the latest numerical relays, and how cyclic load shedding is achieved using the programmable logic.

12.2 Load Shedding

Generation and load need to be well balanced in any industrial, distribution or transmission network. As load increases, the generation needs to be stepped up to maintain frequency of the supply. At times, when sudden overloads occur, the frequency drops exponentially, at a rate decided by the magnitude of overload (or generation loss), and various other parameters. Traditionally, protective relays that can detect a low frequency (with a fixed time delay) condition were generally used in such cases to trip out less critical loads (for example, circuits not supplying hospitals, water supplies, etc.) in order to save the network. Load shedding leads to improvement in the system frequency. However, use of simple under frequency elements was not always successful in ensuring fast load-shedding, which is mandatory for system stability.

It is a normal practice to trip the less critical load. If there is a condition where all loads are determined to be equally important, then the load shedding could take place in a cyclic manner to provide equality among the served loads. This is referred to as cyclic load shedding. The cyclic load shedding can be achieved in any numerical relay by using its programmable logic . The features of the programmable logic are explained below.

12.3 Programmable Logic

Central to any integrated protection solution is flexibility. An area where modern numerical relays can provide great flexibility is in the scheme logic. Traditionally the scheme logic of protection relays, i.e. the internal logic connecting digital input signals, protection algorithm outputs, indication LEDs and output relay contacts, has been fixed by the manufacturer.

Numerical relays can offer relay users the ability to program their own scheme logic into the relay, to satisfy their particular application requirements. The first generation numerical relays provided the option of mapping the internal signals to digital inputs, outputs, LEDs etc. Some basic Boolean equations could also be built.

The programmable logic provided in the latest numerical management relays has redefined the way logic can be built. The basic building blocks of such schemes typically consist of at least the following functions:

- Gate logic
- AND
- OR
- MAJORITY
- NOT
- Timers
- Pick-up
- Drop- off
- Dwell
- Pulse
- Pickup/drop off (out)

In addition to logic functions, many modern relays include math operators, compare, select, flip-flop and memory functions.

The best systems will combine this flexibility with the traditional approach by providing some fixed logic, together with a default programmable logic scheme, based on the manufacturer's experience of typical protection requirements. This is then combined with a logic engine, which allows the user to customise and extend the logic as required.

12.4 Solution for Cyclic Load Shedding

12.4.1 Numerical Frequency Relay

The cyclic load shedding can be implemented in any numerical platform relays (normally frequency based). These relays include programmable scheme logic (PSL). The purpose of this logic is multi-functional. It enables the mapping of opto-isolated inputs, relay output contacts and the programmable LED's. It also provides relay output conditioning (delay on pick-up/drop-off(out), dwell time, latching or self-reset). It also enables customer specific scheme logic to be generated.

12.4.2 Single Stage Cyclic Load Shedding

The simplest and most effective configuration is the single stage, cyclic load shedding. In this configuration, there is one condition (normally one frequency stage) which initiates the load shedding. There is no fixed priority. The feeder or (group of feeders) to be tripped is decided in a cyclic pattern. First trigger trips the first group, next time the second group is tripped, and so on and so forth. The cycle is repeated. This ensures that all feeders are given equal priority. Implementation of cyclic load shedding using programmable logic is as shown below in Figure 6. There are other ways to implement this system that may be optimized in other relays, but this is one method.

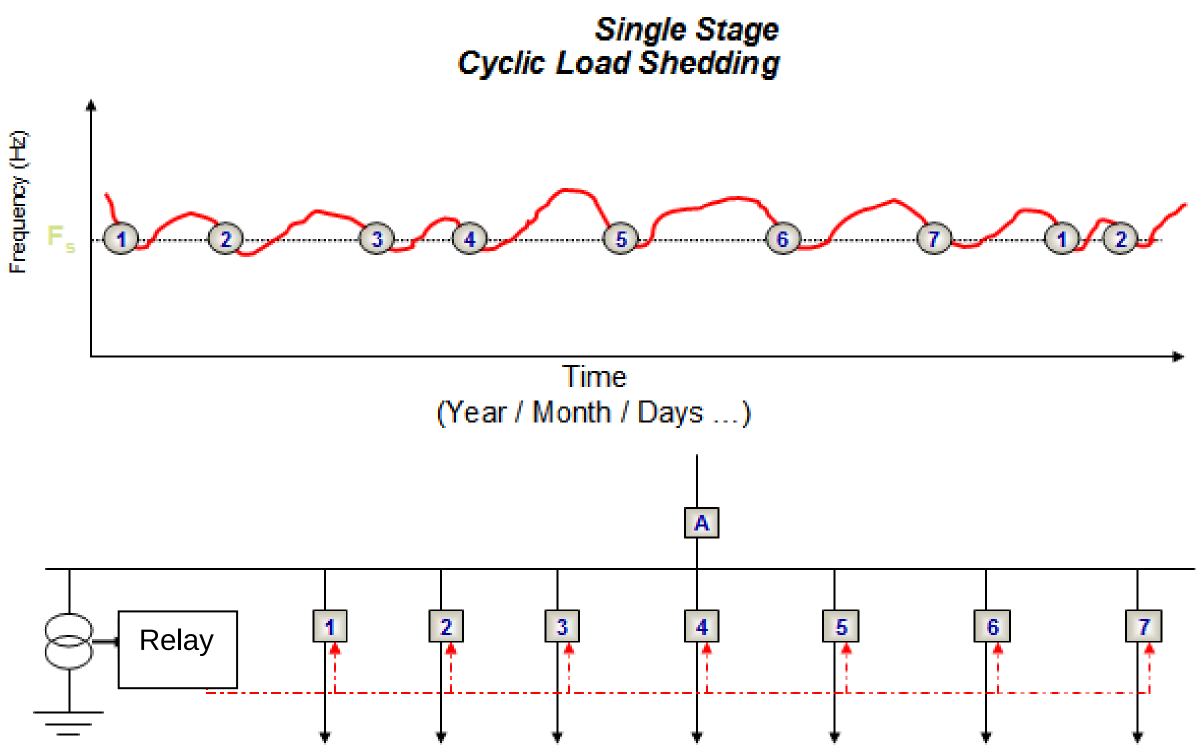

Figure 6. Cyclic load shedding

The operation of the scheme logic is as follows: (note many IEDs now implement internal counters which can simplify this logic)

1. When the frequency goes below the threshold level, it triggers a pulse timer set for a time of 100ms. This pulse is fed to a two-input AND gate, whose other input is a blocking input (for the first Stage) generated after the first stage operates. For the other stages, the other input for the AND gate is a permissive input generated after the operation of the earlier stage. Since the blocking input is not present for the first stage at the start, the AND gate gives a signal to the Relay 1, which is programmed to give a pulse output for 500ms. For other stages since there is no permissive signal, the AND gate does not give any output.
2. The output of the AND gate is taken to a resettable memory circuit, which in-turn initiates a timer (TDPU) of 150ms. The output of this timer goes and blocks the first stage AND gate, and at the same, the timer gives permission for the next stage.
3. The second time the frequency goes below the threshold, the pulse timer gives a pulse of 100ms to the AND gate for second stage, which already has the permissive input gives an input to the Relay 2. It simultaneously energises memory circuit and gives permission to the next stage.
4. This cycle repeats itself and continues till the 7th stage. After the operation of the 7th stage, it resets all the memory circuits and sets the scheme to operate from the start.
5. There is a provision provided for manually resetting sequence and setting the cycle to start from stage 1 through energising a digital input.

The above simple logic can be extended to multistage cyclic load shedding. Care is needed to ensure that the time period of the pickup timer is always greater than the time period of the pulse timer.

12.4.3 Multistage Cyclic Load Shedding

In this configuration, there is more than one condition (normally frequency stage) which initiates the load shedding. Each threshold crossing is considered as a load shedding condition and initiates a feeder (or a group of feeders) to be tripped in a cyclic pattern. This scheme is very effective where shedding one group sometimes is not sufficient. The operation of the scheme logic is as follows:

1. In this scheme we can have typically six stages and up to seven feeder groups. When the frequency goes below the first threshold level, the first feeder is tripped. And when the frequency continues to decrease and reaches the second threshold level, the second feeder is tripped and so on.
2. Assume the frequency increases and again comes below a particular threshold level. Then too the feeders are tripped in their respective cyclic pattern.
3. In the first stage, the first trip frequency signal and the remaining frequency signals (bubbled) are given to an AND gate and this is given to the pulse timer and the remaining operation is as same as the single stage.

A portion of the scheme logic diagram for multistage cyclic load shedding is shown in figure 7 with the stages and feeder impact shown in figure 8 to illustrate how this may be implemented.

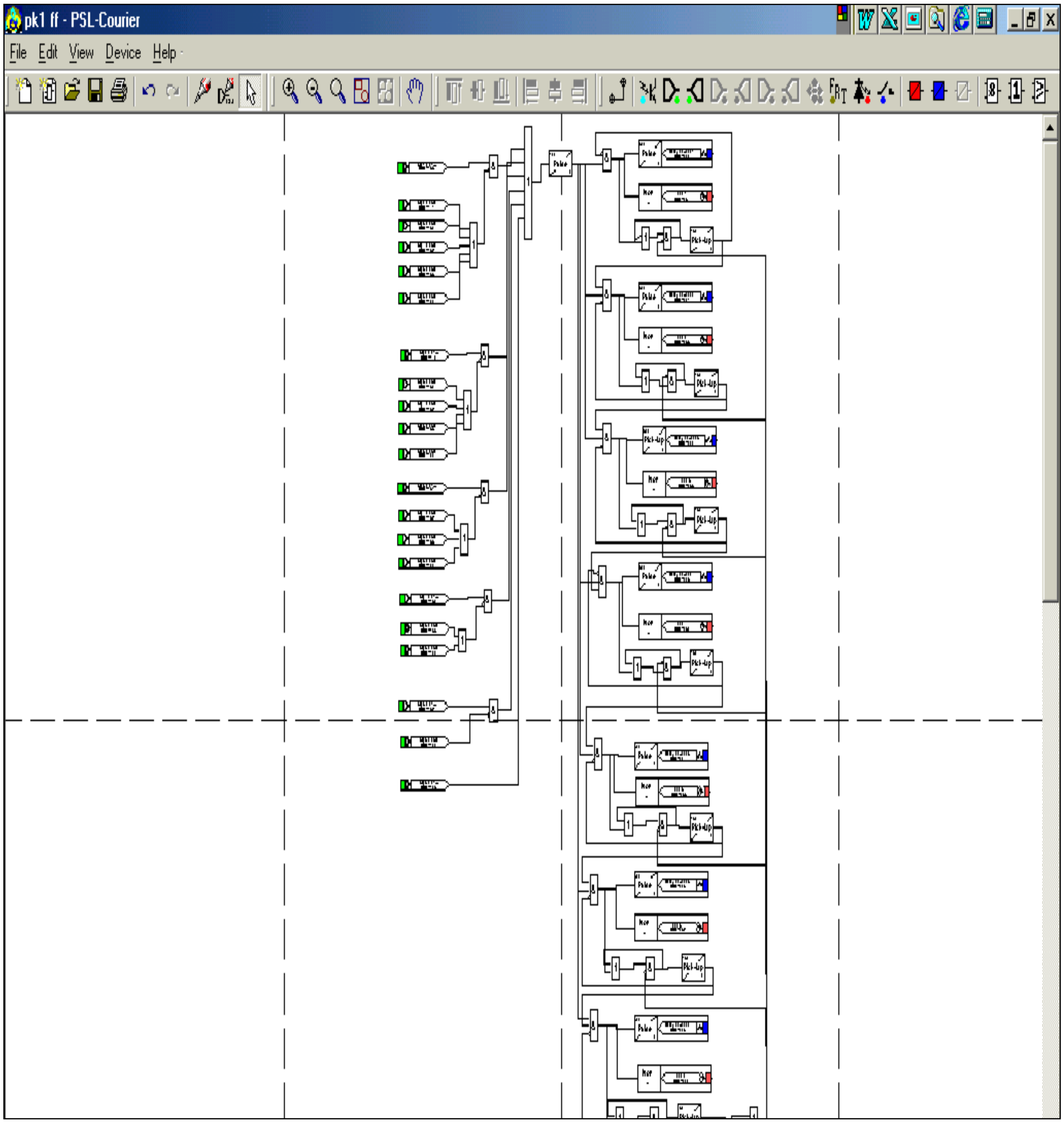

Figure 7. Partial Load shedding Logic diagram (useful for troubleshooting)

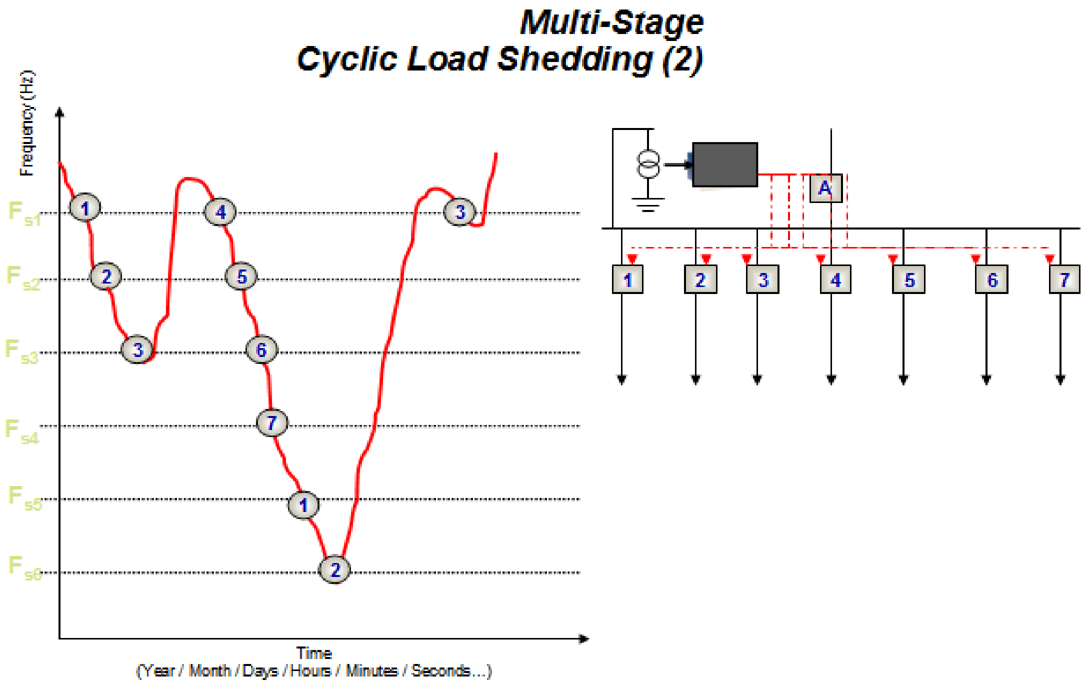

Figure 8. Load shedding stages (note stages 1-3 are restored when frequency increases)

12.5 Unique Features of the Suggested Solution

Cyclic tripping: The logic scheme is designed in such a way that whenever the frequency goes below the threshold level the tripping of the feeders is going to be only in a cyclic pattern. This ensures that all the feeders are treated alike and there is no partiality among them.

Customizability: The number of stages can be varied according to the user's need. The time period of the timers can also be adjusted to the user's requirement.

Future Safe: Normally for load shedding, a feeder, which is not considered critical (no public safety or other critical infrastructure), is tripped. In the future, there may be situation where all feeders are equally important. In such situations, cyclic load shedding will be a safe solution.

13 ADAPTIVE PROTECTION DURING CHANGING SYSTEM CONDITIONS

Adaptive protection aims to adjust settings of protective relaying to the prevailing conditions of a power system. This can be achieved readily nowadays with the multiple setting groups that numerical relays have.

Power system operating conditions change continuously. This is due mainly to the normal variation of loading at busbars throughout the daily, weekly or seasonal periods. Relay settings cannot be readjusted even temporarily for all operating scenarios, and therefore appropriate settings may be calculated for a wide range of conditions, which would guarantee reliability, selectivity and fast operation. Normally the settings are calculated for the highest loading conditions but that is not necessarily always the case.

There are many other reasons that produce changes in the loading conditions which may result in sub-optimal or misoperation of the relays. These reasons could be classified in two main groups:

1. Changes in Topology of the Distribution/Transmission System
2. Automatic Feeder Reconfiguration of Distribution Systems

13.1 Changes in Topology of the Distribution/Transmission System

Power systems are continuously exposed to changes in topology due to a wide range of operating conditions, occurrence of faults or maintenance activities. Relay setting studies for the different cases have to be undertaken to determine if these changes in topology impact the proper operation of the protective system. If this is the case, and the relays do not have the multiple setting group functionality, it is important that the most stringent condition be considered to adjust the relays.

If the relays have multiple setting groups as the case is with numerical protections, then different setting groups could be used. The groups could be initiated by inputs associated to the condition corresponding to the new topology.

The figure 9 illustrates the situation. In this case several scenarios can be identified as the following:

- System operating normally with all the sources
- Losing one of the transmission lines
- Losing one of the power transformers
- Losing the connection to the main grid
- Losing the local generator

As mentioned before for each scenario it is important that a coordination study be performed and if results impact the relay settings, a new group could be assigned to the scenario. Inputs for each condition could be received in the relay for the change to be implemented. Typically the change of position of a breaker could indicate the need of change in condition.
In the case of figure 9, we illustrate these conditions where one of the power transformers is lost either by fault or maintenance.

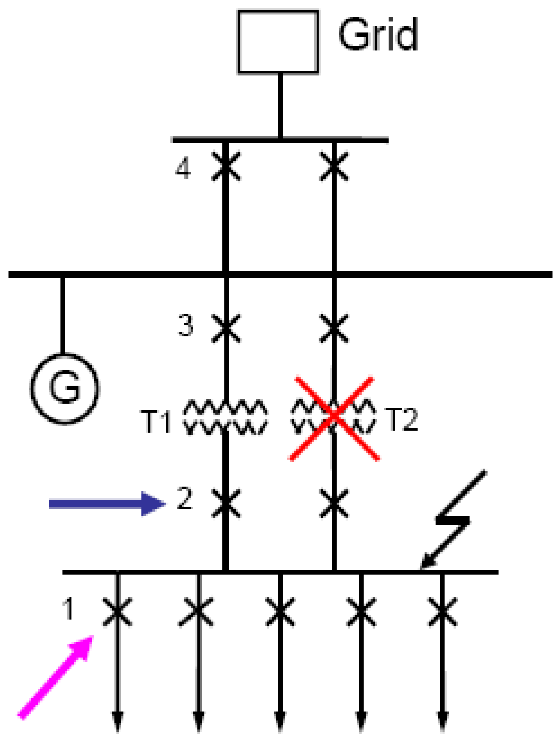

Figure 9. Setting group application

When both transformers are in service, the time current characteristic of R1, it is desirable for the relay associated with feeder 1, to operate faster than relay R2, which is associated with breaker 2 which is a backup for breaker 1. Figure 10 shows R2 as operating faster, but R2 sees only half the fault current I_f due to the current split between the two transformers.

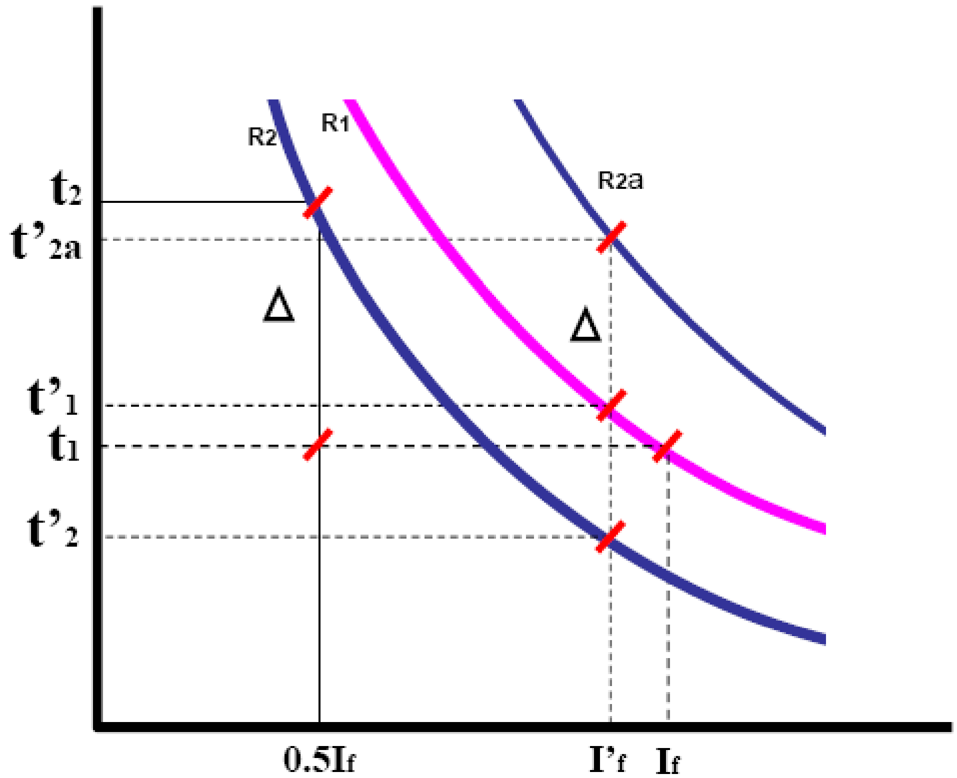

Figure 10. Coordination changes with setting group

However if one transformer is lost, the total current reduces to I'_f. In this case the current flows through the remaining in service transformer, causing R2 to operate faster than R1. This would cause an outage to all of the feeders for a fault on feeder 1. Therefore the time current characteristic may be changed to R2a for an outage of the transformer. Once the transformer is placed back in service, the time current characteristic of the LV side relay goes back to R2. The input to the relay to indicate the prevailing scenario could be taken from the auxiliary contact of the LV side breaker of the transformer.

13.2 Automated Feeder Reconfiguration

Automated feeder reconfiguration has become a major feature of new distribution systems. For decades, distribution systems were considered with rigid topologies and limited possibilities to allow changes in configuration.

The improvement of switches , numerical protection, and communication systems provided the application of feeder reconfiguration to modify the topology of distribution networks.

Feeder reconfiguration consists of network topology modifications by operating normally closed (NC) and normally open (NO) switches. Switches located along the feeders are NC and allow

isolating sections when required. These are also called section switches. Switches connected between two feeders are Normally Open NO and allow transferring loads between two neighbour feeders when the switches are closed. These are also called tie switches.
The figure 11 illustrates the location of NO and NC switches in a distribution system of three feeders.

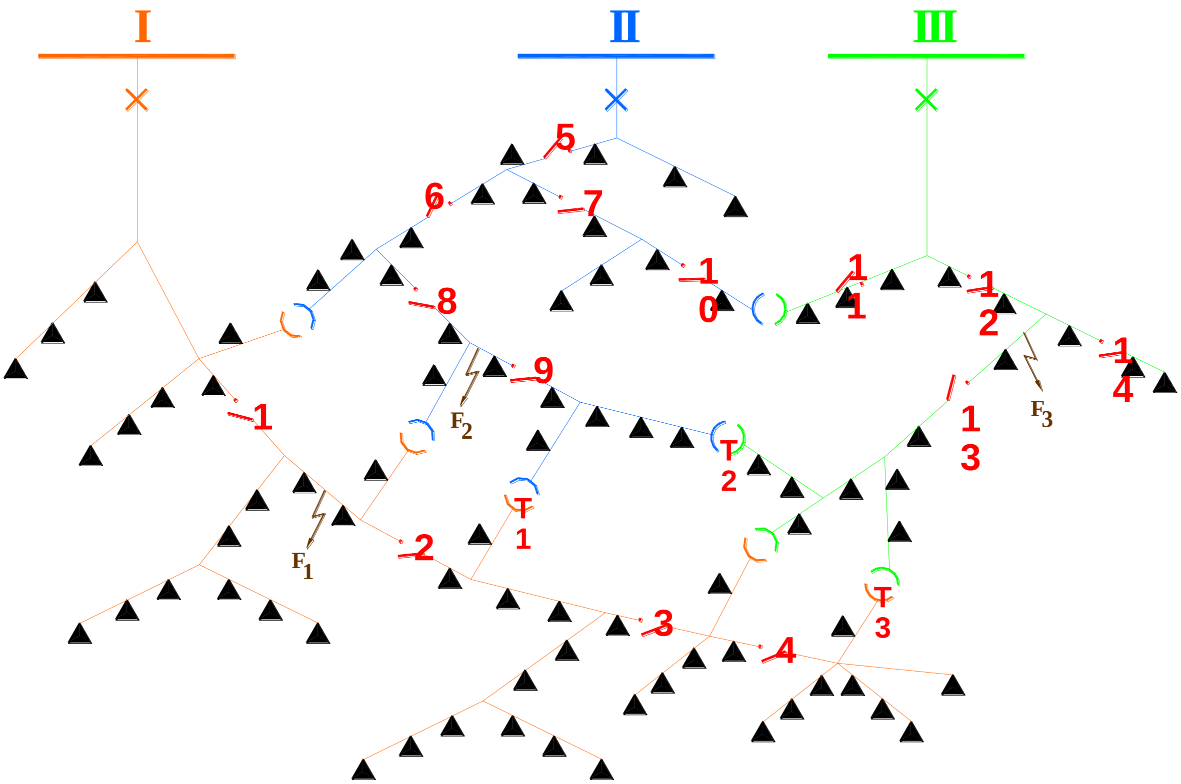

Figure 11. Distribution system with normally closed and normally open switches

For each possible condition, it is important that appropriate settings be calculated not only for the relay associated to the breaker of the substation, but also for the reclosers and switches along the feeders if they are equiped with protective devices. In this case the inputs for the setting group changes could be associated with the operation of the NO and NC switches.

Table 1 illustrates for each of the three faults shown in the figure, the possible operation of the switches, which in turn suggests the possible new topologies. These have to be considered by the protection engineer when calculating the settings.

Feeder Switch Operation Table		
Pre-fault conditions: all of the tie switches are open and the sectionalizer switches are closed.		
Fault Location	Sectionalizer Operation	Tie Switch Operation
F1	S1 and S2 Open to isolate Fault 1	
		T1 or T3 Close to re-establish the load. Both could close if S3 or S4 are open. The transferred load is then split in two feeders.
F2	S8 and S9 Open to isolate Fault 2	
		T1 or T2 Close to re-establish the load.
F3	S12, S13, and S14 Open to isolate Fault 3	
		T2 or T3 Close to re-establish the load

Table 1. Possible Reconfiguration Topologies

When carrying out the reestablishment, it is important that the operations that are executed acknowledge that the system satisfies some restrictions, such as:

- The capacity of current of the transformers and lines are be within specified limits
- The voltage drop stays inside an established margin.
- System continues being radial
- The Number of operations of the equipment has limits
- Priority of the feeder
- System is balanced in the best possible way
- The coordination of the protection is maintained

14 SITUATION ANALYSIS

14.1 Where Are We Today?

Today's transmission systems have a fair amount of intelligence, with the most sophisticated probably being the energy management system (EMS) with its automatic generator control (AGC). Within these systems, a variety of advanced applications such as state estimation, contingency analysis, voltage stability and other applications are run on a regular basis. However, as these network models continue to get larger and larger with more detailed models, computation time has become problematic even with changes in CPU speed and other technical gains in computing. Also, the typical 2-4 second data scan rates, when combined with the computational time, are in some cases too long in providing actionable information.

Besides the EMS system, there is other information available to the operator. Some of these are dynamic line ratings, synchrophasor data and variety of condition monitoring information. The majority of this information tends to reside outside the EMS and may not be well integrated into the overall situational awareness capabilities in the control center.

There is a fair amount of information available to the system operator however; much of the data is in the control center and not readily available to the rest of the enterprise. To make this data available to the broader enterprise some utilities have installed data historians that allow asset managers access. This is not a trivial task and in most cases requires significant administration effort to translate coded point tags into understandable point tags. For example, point tags in an EMS may be something like “ELM345B1VA” which represents “Elmhurst 345Kv Bus 1 A Phase Voltage”. When tens of thousands of points are involved, this translates into a significant task. As the system changes with field asset upgrades, there is constant maintenance.

14.2 What Does the Smart Grid Offer?

The recent “Report to NIST on the Smart Grid Interoperability Standards Roadmap” provides extensive references to a number of standards that are suggested to be used as the foundation for the Smart Grid. Most if not all of these standards are designed to have interoperability and self description as key elements of their makeup. The interoperability feature minimizes the work effort to interface applications and data between domains. The self description feature further minimizes the labor component by automatically describing a given data element. It also eliminates many of the human errors associated with typing and labeling data points since the labels get derived from predefined objects.

14.3 Sensors and Actuators

The role of sensors and actuators in the Smart Grid is one of the fundamental elements required for successful operation of the grid. It is through these devices that the actual power system’s reaction to various inputs and outputs is measured. As in classic control systems, it is through sensors that vital information about a variety of conditions is received. The sensors convert voltage, current, phase angle, position status and other data into manageable signals that are either analog or digital in nature. One of the most enduring sensors of the power system is the protective relay and its associated potential and current transformers. Deriving additional value from these devices has been underway shortly after the adoption of the microprocessor based protective relays. Today many vendors provide condition information within their protection relays straight from the factory. However, in many cases, the information does not make its way to the control center or elsewhere due to communications or other limitations. With the ubiquitous communications that are part of the Smart Grid this issue evaporates.

Where they are available today, these sensor signals are usually sent to a centralized operations center for a geographic region. At the operations center various control computers process this sensor data into information and control signals. Some of the information is routed to displays in the control center for system operators to use in their constant monitoring and management of the grid. The information is also routed to generators to provide the continuous balancing of load and generation and other automatic functions. The system is also capable of responding to manual inputs from system operators for manual actions such as energizing and de-energizing lines for maintenance.

There are over 500,000 microprocessor relays installed in North America, based on one manufacturer’s sales figures. This would include both transmission and distribution, but regardless of the split, this is a large penetration of a single vendor’s device. Taking into consideration the other suppliers, there is significant penetration of these relays. Each of these relays contains within it a significant number of data values that go beyond what is necessary for protection. Included in many of these devices are digital fault records, sequence of event recorders, calculation of I^2t which is a measure of thermal energy associated with current flow, synchrophasor measurement, and a very large quantity of other measured and calculated values including analog values such as voltages, currents and digital values like circuit breaker contacts “a” and “b” closure time. Once again due to the limited bandwidth out to the field assets, this valuable information remains in the relay and is seldom ever used by the operations or asset management staffs. If one were able to routinely gather this type of data, some very simple analytic processes could be setup by the maintenance staff. By accumulating the I^2t value for each circuit breaker over time, one could develop an algorithm to trigger maintenance of the breaker at a prescribed value that would be indicative of contact wearing beyond an acceptable value. Also, by monitoring the contact timing values, one could identify breakers that operated slowly and once again perform maintenance. The maintenance task would probably be as simple as lubricating and exercising the breaker. Without this knowledge, the task may become the replacement of a failed breaker, since the slow opening caused excessive arcing and heating.

The influx of sensors into the electric utility marketplace has been extensive. The capability of the installed microprocessor based relays is also extensive. The limitation to fully utilize this data for both operations and management has been limited bandwidth connecting the field assets to the utility enterprise, as well as the ability to interpret the information.

An actuator is either an electrical or electromechanical device that responds to the output signal provided by the control system. In the electric utility enterprise, actuators are fairly limited. They include classic items such as circuit breakers, phase shifting transformers, and special protection schemes (or remedial action schemes). Some modern actuators are high voltage direct current controls (HVDC) and flexible AC transmission systems (FACTS). There are other actuators related to generation control that will not be covered in this report.

14.4 Using IEC 61850 for Condition Based Maintenance

Condition Based Maintenance is an area that would benefit by the adoption of the IEC 61850 standard, and the monitoring resources it offers.

Today the majority of equipment maintenance in power delivery systems is carried out by either corrective or preventive maintenance. Corrective maintenance lets the component or system run until breakdown or fault before maintenance action is considered. For this reason corrective maintenance is also known as run-to-failure maintenance. In contrast, preventive maintenance is carried out at predetermined intervals according to prescribed criteria and intended to reduce the probability of failure or the degradation of the functioning of an item. This is done by repair or component exchange in preset intervals. Preventive maintenance is sometimes called planned, or time based maintenance.

It has been shown that these traditional maintenance techniques, corrective and preventive, are very costly and inefficient. To try to maintain the correct equipment at the right time, predictive maintenance techniques were introduced. In predictive maintenance, the maintenance intervals are decided according to the condition of the equipment rather than time in service or number of operations. Predictive maintenance is also known as Condition Based Maintenance (CBM). CBM relies on monitoring selected parameters of the equipment in a manner that the ongoing condition can be continuously or periodically assessed and maintenance is initiated based on the present needs of the equipment condition (14). The main purpose of CBM is to eliminate or minimize breakdowns and prolong the preventive maintenance intervals. As a result, an increase in equipment availability is achieved, and then power availability and quality is increased too.

One of the key concepts behind performance based asset management is to optimize maintenance. Maintenance is frequently one of the biggest controllable expenditures in a company (15). For that reason, the introduction of the condition based maintenance concept in power delivery substations and elsewhere in the system will allow electric power companies to optimize their maintenance and operation costs, while at the same time, increase the quality and continuity of the electrical supply due to an increase in the efficiency of devices.

Condition monitoring is a major component of predictive maintenance. With the appearance of IEC 61850 series, condition monitoring and other monitoring tools become easier to implement in automation substation systems. It defines among its information models several items that help to determine the condition of substation equipment. For example, the logical node used for modeling circuit breakers (XCBR) includes the sum of switched amperes (SumSwARs) and one operation counter (OpCnt) as some of their data attributes. The sum of switched amperes in a circuit breaker, also known as I^2t, and the number of switching operations are some of the key monitoring parameters to know the circuit breaker condition. In a similar way, several logical nodes include key data attributes needed to know the condition of power transformers.

Examples of logical nodes used to monitor transformer condition are:

- YPTR: includes the winding hotspot temperature.
- YLTC: includes key attributes to monitor the tap changer condition.
- ZBSH: provides properties and supervision of bushings as used for power transformers.
- SARC: includes attributes for monitoring and diagnostics for arcs.
- SPDC: includes attributes for monitoring and diagnostics for partial discharges.
- SIML: supervises liquid insulation medium such as oil used in transformers and tap changers, including attributes like relative saturation of moisture (H2O), insulation liquid temperature (Tmp) and measurement of hydrogen concentration (H2).

As described in (16), in the future all these nodes will be extended and included in logical node group S, specially dedicated to sensors and monitoring. Other logical nodes also useful for condition monitoring are described in section IV that belong to metering and measurement logical node group M, such as MMXU, MMXN, MMTR, MSTA, MHAI or MHAN. (17)

14.5 Condition monitoring

The use of more sophisticated control algorithms and technologies such as expert systems, inference engines, knowledge bases and other advanced processing approaches have been studied for over twenty years. In trying to move forward with these ideas in power delivery systems, the field has typically run into implementation challenges due to the high cost of communications systems. There were no cost effective mechanisms established to effectively integrate field equipment to enable the widespread use of advanced control algorithms. With the emergence of next generation open standards for communications that are being encouraged with the new Smart Grid deployments, companies may choose to capitalize on the opportunity and leverage the lower cost options now available. This is supported by IEC 61850 as discussed in the previous section.

14.6 Summary

In terms of overall vision, Smart Grid enabled condition monitoring will be a powerful tool for electric utility companies in many ways. There are five fundamental technologies that the DOE lists that will drive the Smart Grid. These are: integrated communications, sensing and measurement, advanced components, advanced control methods, and improved interfaces and decision support.

Using the Smart Grid Conceptual Models, which is a set of views (diagrams) and descriptions that are the basis for discussing the characteristics, uses, behavior, interfaces, requirements and standards of the Smart Grid, one can postulate different mechanisms by which the Smart Grid enabled asset management process may be enhanced. By investigating further the Smart Grid conceptual model shown previouslyit is shown that the majority of the asset management function is contained within three areas. These are the Operations, Transmission and Distribution areas. Each of these domains will benefit significantly from the Smart Grid since monitoring of assets within the Smart Grid will be more cost effective and beneficial than previously since the required infrastructure will be in place to support the Smart Grid functions broadly and not just for equipment monitoring. Sensing and measurement technologies are a key enabler of the Smart Grid.

The “Report to NIST on the Smart Grid Interoperability Standards Roadmap” provides extensive references to a number of standards that are suggested to be used as the foundation for the Smart Grid. The interoperability feature minimizes the work effort to interface applications and data between domains. The role of sensors and actuators in the Smart Grid is one of the fundamental elements required for successful operation of the grid. In the power delivery Smart Grid, sensors will increase in both type and quantity.

Developing the proper foundation elements, including security and leveraging industry standards to ensure interoperability between systems and devices helps to keep costs reasonable over the long term. Finally, the information systems organization needs to be involved in the process all along the way.

While condition monitoring concepts have been around for many years, during much of that time, decision makers have had to settle for less than ideal conditions when it came to asset specific information. In most companies, the maintenance manager has little asset specific data or the data was expensive to obtain from the field. With the advent of the Smart Grid and its extensive communications infrastructure and computational capability, the asset manager will be able to very specifically determine the health and performance of specific assets and the system conditions the asset experiences. Through this report one can envision a much higher caliber asset management process and also a much more automated one. Once the Smart Grid starts to get deployed at electric utility companies, the asset manager will be one of the primary benefactors and the performance level of the organization will take a significant step up in analytical capability and understanding asset performance.

15 USING EXISTING PROTECTION FUNCTIONS

15.1 Measurements

The Standard Handbook for Electrical Engineers (Thirteenth Edition, 3-2.1,) states: “Measurement of a quantity consist either of its comparison with a unity quantity of the same kind or in its determination as a function of quantities of different kinds whose units are related to it by known physical laws.”

In keeping with the above definition, Protective Relays produce two types of measured quantities that are useful to the Smart Grid. Directly measured (the first half of the formal definition, for example, Amps, a direct measurement of current) and calculated (the second half, for example Watts, the product of Volts times Amps) While these values may or may not be directly used by the relay for protective functions, most manufacturers make these values available to outside devices via communications.

Directly measured values - These values are first order measurements (they are not derived from any other measurement.) Relays capture a power system's voltage phasors, current phasors, frequencies or a combination of the three. While the relays themselves measure with a metering or near-metering accuracy, they are connected to non-metering quality instrument transformers. Protection grade current transformers are sized so they do not saturate under large fault currents. This is accomplished at the price of accuracy under low to normal system currents. The magnitudes and angles of the Current phasors are most affected under these conditions, while the measured frequency is relatively accurate. While useful, it is important that the margin for error of these magnitudes (and any calculated value that is based on these values) be taken into account when used in Smart Grid applications. In the future, new sensor technology offer the promise of near revenue quality accuracy without the risk of saturation during faults. As these devices are deployed on the grid, the metering accuracy of the protective devices will be nearly that of traditional meters.

There are examples where the relay itself uses only a calculated value, while a Smart Grid application may be interested in the fundamental values that underlie it. A low impedance bus relay will have the bus CTs wired individually to the relay, and the relay will measure the phasor of each circuit individually. While the relay will add these phasors together digitally and calculate the differential current (which is used internally for the bus protection), the individual phasor measurements are available for export from the relay.

Protective relays also monitor “status contacts,” which consist of only binary information. 52a and 52b statuses for circuit breakers, disconnect switches and circuit switchers, sudden pressure alarms, manual switch positions, etc. can be monitored via the Protective Relay.

Most major relay manufacturers are beginning to incorporate Synchrophasors into their products. These Phasor Measurement Units (PMUs) will allow Smart Grid operators to capture synchrophasor data without the need for extra stand alone devices.

Many modern relays also have milliamp inputs (0-1 mA, 4-20mA, etc.) Traditionally, these are connected to RTDs and bring device (Transformer/Motor) temperature data into the relay. Operators on the Smart Grid could benefit from this data to help more accurately determine when transformers are approaching their operating limit.

Breaker operation counters may also be a benefit. If the goal of a switching operation can be accomplished using a breaker that has less operations on it then another one, that breaker can be used, spreading out maintenance outages.

Calculated Values - Calculated values are those derived from the primary values. Practically all modern multifunction microprocessor relays have the ability to provide rms Voltage, rms Current, Watts, Vars, VA, Watt Hours, etc. The more advanced devices typically deliver Harmonic information, ranging from the systems' Total Harmonic Distortion (THD) to individual harmonics (2nd, 3rd, 4th order, etc). The benefit of these values to the Smart Grid is obvious. Less obvious are more device specific values. Differential currents measured by both line and transformer relays may be used in certain situations to detect abnormal operating conditions, and allow operators of the Smart Grid to compensate before a catastrophic failure takes place. Breaker and a Half schemes (i.e. supplying a radial transmission line) will have each CT from the two breakers brought into the relay individually, where they are digitally added together to determine line currents. Calculated values are available to the Smart Grid in the same manner as directly measured values.

This data is usually available from the relays via DNP or Modbus protocols. Traditionally, it is aggregated in SCADA systems' Remote Terminal Unit (RTU), which is then accessed to retrieve the desired data.

A more modern approach would be to publish any relevant analog values on an Ethernet LAN dedicated to substation protection and control, better known as IEC 61850 GOOSE messaging. As 61850 becomes more prevalent for substation control (sending blocks and permissive between relays, distributing 52a and 52b contact information, etc.) user's will have the ability to access the analog data over the same existing network, without the need to add any physical wires in the substation. For security purposes, this data will most likely be aggregated in an RTU type device, which in turn will be accessed from beyond the substation.

15.2 Synchrophasors

Phasor Measurement Unit (PMU) technology provides phasor information (both magnitude and phase angle) in real time. The advantage of referring phase angle to a global reference time is helpful in capturing the wide area snap shot of the power system. Effective utilization of this technology is very useful in mitigating blackouts and learning the real time behavior of the power system. With the advancement in technology, the micro processor based instrumentation such as protection relays and Disturbance Fault Recorders (DFRs) incorporate the PMU module along with other existing functionalities as an extended feature. The IEEE standard on Synchrophasors (C37.118) and IEC 61850-90-5 specify the protocol for communicating the PMU data to the Phasor Data Concentrator (PDC).

Synchrophasors raise the possibility of new solutions to power system problems while also bringing up issues that are important to be addressed.

15.2.1 Solutions

The following list includes solutions that may be provided by synchrophasor measurement based systems.

- Utilize PMU data available at existing PDC rather than stream data from multiple sources.
- Real Time Power System Measurement
- State estimation-Real time monitoring and control studies
- Transient Stability improvement and possible control
- Real time information helpful in observing stability of the system (e.g. PV curve)
- Mitigation of outages.
- Improvements in System Modeling and Optimization
- Transmission line modeling
- Generation modeling

- Real time control (possible, but not very easy)
- Real time capabilities to analyze good-and-bad data
- PMUs can provide useful information for Wide Area Monitoring, Protection and Control

15.2.2 Issues

- Communications Issues
- Need a dedicated server application designed to accept large volume of PMU data and analyze the data depending on application requirement.
- Just the real time data availability is not enough
- Interoperability of different vendor PMUs
- Need for more customer friendly PMU calibration and testing devices to meet C37.118 compliance levels

15.3 Status Information

Information available from the PRD is extensive and is already available inside the unit as it is required for protection. The following list shows different types of status information and this is summarized in Table 2.

Identify the functions and data available in PRD that are "status" information.

- External device status that can be wired
- Internal status of the PRD (also can be called IED).

External device statuses that are useful for Smart Grid :

- Breaker status
- Switch status
- Other distribution field devices such as reclosers, sectionalizers, cap banks.
- Mechanical parts (i.e. motor condition, temperature sensor, sound sensor)

Internal status of the PRD :

- Overall health of the PRD (device malfunction)
- Communication processor/card board status
- Specific protection board failure mode
- Loss of power supply
- Loss of communication to remote device/s

Describe the use of these statuses information in relation to Smart Grid technology
Using external device statuses to:

- Change active protection setting group (e. g. sensitivity of trip element, time delay, switching from current based protection to impedance based, directional to non-directional, etc.). This is already known in power engineering as adaptive protection:
  - Adaptation to loading vs. generation requirement/condition.
  - Adaptation to power factor requirement
  - Adaptation to voltage sag condition
  - Automatically scheduled or adjust maintenance requirement on equipment.

Using internal device status described above to:

- Change the local zone of protection defined by the PRD. For example, if the primary feeder relay goes into failure mode, the bus protection will be adjusted so it can cover as primary protection of that feeder.
- Change the speed of operation of back up scheme. For example if pilot communication has failed, then speed up zone 2 tripping.

Common Protective Relay Device (PRD) Status	Smart Grid function/area/features						
	Self healing grid	*Consumer Participation; demand response support*	*Resist Attack*	*High quality power*	*Accommodate Generation options; decentralization of power generation; distributed generation*	*Enable Electricity Market*	*Optimize Assets; load adjustment; grid optimization*
Direct Status							
Bkr/disconnect/swc status	x	x	x			x	
Pressure Status	x						
Derived Function							
Fault location/direction	x		x				
Power Factor/Quality		x		X	X	x	
Load Encroachment					X		x
Access Level Alarm			x				
Device Malfunction Alarm	x		x				
Out of Step condition		x			X		x
Operation Counter/Rate		x	x	X			
Measured Values							
Frequencies		x		x			
PMU				x	X		
Equipment loading characteristic/history		x		x		x	x
Equipment rating capability		x		x		x	x
Equipment health	x		x				x
Currents	x						x
Voltages	x						x
Temperature		x			X	x	x

Table 2. Status points in the PRD, availability and function

15.4 Waveform, Disturbance and Event Recording/Reporting

During major power system disturbances or events such as faults, power swings, loss of generation, loss of load, energization of equipment, or high harmonic loads, modern IEDs have the capability to record digital time tagged events as well as current and voltage oscillography. Types of substation IED recording equipment include digital fault recorders, microprocessor relays, phasor measurement units, sequential event recorders, and smart meters. Regarding the digital time tagged events, regional coordinating councils generally require that they are time stamped accurately to plus or minus 1 millisecond. Whereas the voltage and current oscillography is recorded in transient data files, transient data files were originally made in proprietary formats. Later with the advent of the COMTRADE file format for fault records, the task of transient data translation and archival of multiple manufacturers' equipment on a single platform is available to perform a number of applications. Some of these applications include; (18)

- Analysis and identification of undesirable sources of harmonics and unbalances.
- Analysis and location of power system faults.
- Analysis of events leading to power system instability.
- Use of data in digital form to test digital relaying algorithms
- Reproduction of data in analog form to test protective relays.

The proper collection of power system disturbance data that is identified, integrated and synchronized from multiple recording devices allows for efficient forensic analyses of the power system and multiple protection schemes after a major disturbance.

15.5 Fault Location

In the event of a permanent fault on the distribution or transmission part of the power system, utility operators need to find the fault location so they are able to dispatch line crews as quickly as possible to the correct location to make the necessary repairs. For the purpose of the Smart Grid, fault location data is just one of functions the modern micro-processor relays are capable of providing.

For transmission lines with modern line protection relays there are two common methods for obtaining fault locations. The first method is a one-ended impedance-based measurement where the modern relay calculates the location of the fault from the measured apparent impedance (19). There are a number of variables that may affect the single-ended fault location calculation. For the one ended impedance method, remote communications with a data concentrator or a SCADA RTU is required to obtain the fault location data. Using a communication protocol that supports time stamping, the data is sent to the concentrator or SCADA RTU as an analog in units of kilometers or miles with the time of the event. It is important that the concentrator or SCADA RTU be configured to lock in the analog value of the initial calculated fault location for a set time that exceeds any reclosing operations, thus preventing this value from being over written by new values calculated from reclosing operations. If the only communication protocol that is available does not support time stamping then the concentrator or SCADA system could then be configured to hold this value for a predetermined amount of time that corresponds to how long it will take the system operator to confirm that the polling time corresponds with the fault event. After this predetermined time the concentrator or SCADA system could reset the fault value to zero so the system operator can be confident that when the next fault occurs that the data is correct.

The second method available in modern transmission protection relays is a two terminal method where data from both ends of the transmission line is used to calculate fault location (20). There are a number of techniques available for utilizing the two terminal methods, however they share the same minimum requirements that the data share corresponding time codes and be delivered to a single location. For the two-ended method, the risk of reclosing operations affecting the fault calculations is unlikely to occur because reclosing is typically staggered and event data from a reclose attempt at the local end would not be time corresponded with data collected at the remote end. Similar to the one ended method, the calculated fault location data could be presented to a system operator in units of miles or kilometers with a time stamp that corresponds to the power system event.

Primary distribution:

Since the primary feeder relays now have synchrophasor capabilities, the following fault location method can be employed to locate the fault on a segment of a primary feeder [2].

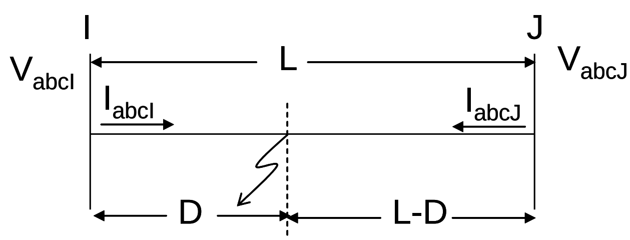

Figure 12. Faulted section between bus I and bus J

As shown in fig. 12, let the fault be at a distance *D* from bus *I*. Let the voltage at the fault point be denoted by V_{abcF}. It is assumed that the line-currents and phase voltages at buses *I* and *J* - V_{abcI}, V_{abcJ}, I_{abcI}, I_{abcJ} - are measured as synchrophasors. $z_{abcI\text{-}J}$ is the three phase impedance matrix per unit distance for line segment I-J. Following equations can be formed to represent the scenario in fig. brahma1:

$$V_{abcI} = V_{abcF} + (z_{abcI-J} D) I_{abcI} \qquad (1)$$

$$V_{abcJ} = V_{abcF} + z_{abcI-J} (L - D) I_{abcJ} \qquad (2)$$

From (1) and (2),

$$V_{abcI} - V_{abcJ} + Lz_{abcI-J} I_{abcJ} = Dz_{abcI-J} (I_{abcI} + I_{abcJ}) \qquad (3)$$

Equation (3) can be written as:

$$Y_{abc} = DM_{abc} \qquad (4)$$

In (4), both Y_{abc} and M_{abc} are known 3×1 vectors. Therefore, (4) represents three complex equations (or six real equations) with one unknown “D”. The solution for *D* can be found using the least square estimates [2] as:

$$D=(M_{abc}^{+}M_{abc})^{-1}M_{abc}^{+}Y_{abc} \qquad (5)$$

M_{abc}^{+} in (5) is the conjugate transpose of M_{abc}. This method has been shown to be immune to fault resistance, and pre-fault conditions. Since the method does not depend on sequence components, it can handle the inherent unbalance in distribution systems.

Secondary Distribution:

Usually, secondary distribution networks are protected by fuses. After connection of distributed energy resources to these networks, for example, at residential and commercial locations, secondary distribution networks will no longer remain single-source. Fault currents from multiple sources will result, potentially disrupting the coordination between fuses [3]. Therefore, fuses cannot be depended upon to identify the faulted section, which is the first step towards fault location. Though this problem is unlikely to be resolved economically with existing protection devices, it deserves a mention here as an important problem that will need additional sensors with appropriate communications at strategic locations to locate the faulted section and fault.

15.6 Volt/VAR Management Equipment

VVMS Controls - Available Local Data

- LTC or Regulator Tap positions (#1)
- Local voltage, current, kW, kvar, frequency, PF (#2)
- Paralleled transformer status, currents, voltages (#3)
- Indication of transient high (fault?) current occurrence (downstream fault w or w/o tripoff?) (#4)
- Local power direction
- Indication of tapchanger motor condition
- Indication of tapchanger tap-contactor condition
- Harmonics (choice to 31st) and THD
- CBEMA Monitoring
- Voltage reduction strategy status
- Neutral position indication
- Various Alarms

***LTC or Regulator Tap positions (#1)**

1) The tap position of Load Tap Changer (LTC) transformers can have an effect on the transformer's "optimum" differential relay settings. These "optimum" setpoints of a transformer differential relay are dependent on the ratio of the high and low side CT's in relationship to the transformer winding ratio. Since LTC operation changes the transformer ratio it stands to reason that tap position information could be important in establishing the relay sensitivity or slope.

2) Many relay schemes have a "primary area of protection". These areas tend to overlap (secondary "area of protection") to provide backup for each area. The changing tap positions of distribution feeder voltage regulators (think autotransformer) causes a current and a voltage difference between the regulator source and load side (maximum of 20%). The coordination of protection located on the regulator's "source" line section with protection located on the "load" line section could be enhanced with knowledge of the tap position (turns ratio) of the interposing tapchanger.

3) Similarly, in LTC transformer applications, the coordination of primary side protection and secondary system protection could be enhanced by knowledge of the immediate tap position of the LTC.

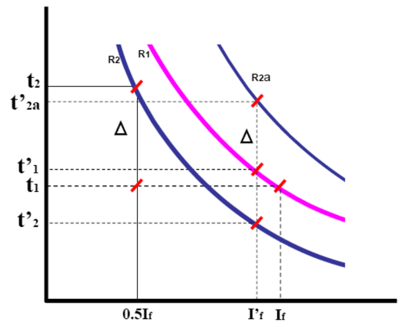

Figure 13. (repeated from fig. 10) applicable for visualizing items 2) & 3) above]

***Local voltage, current, kW, kvar, frequency, PF (#2)**
Relay settings cannot be readjusted even temporarily for all operating scenarios, and therefore appropriate settings are normally calculated for a wide range of conditions, which is intended to guarantee reliability, selectivity and fast operation. Normally the settings are calculated for the highest loading conditions but that is not necessarily always the case.

It may be possible that loading conditions at the locations of tapchangers or capacitor controls along with some of the control derived quantities may be useful in optimizing protective relaying settings or operation. This could be especially important as SG systems become more interconnected to greater accomplish the SG system goals.

These controls could have the ability to analyze conditions at tapchange or at equipment switching and provide confirmation or additional details regarding system topology changes discussed in section 6.2 of the PSRC C2 report (in progress).

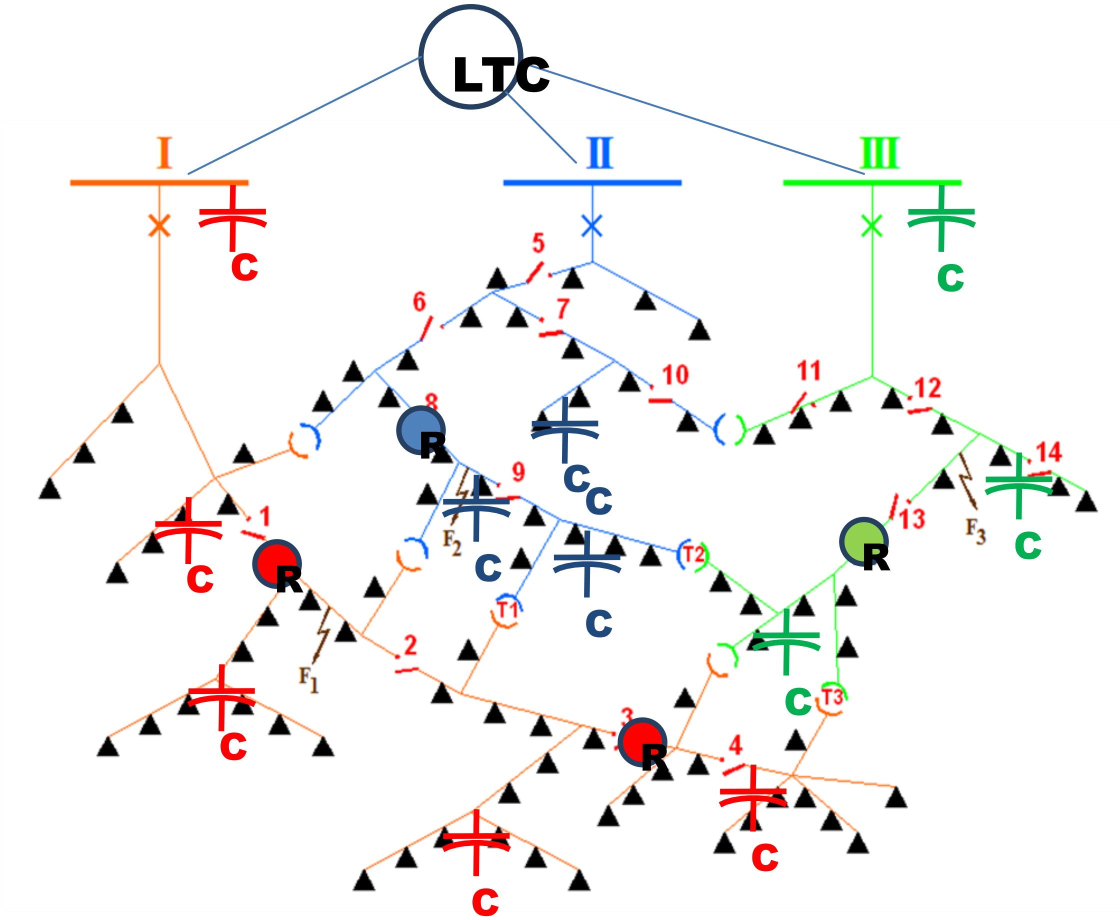

Figure 14. From PSRC WG C2 Report: Section 6.2: SG System with typical added regulators & capacitors

Figure 14 (without added regulator & capacitor locations) above was used to explain the normal operation of section switches and of tie switches a three feeder SG distribution systems. Operation is predicated on continuous radial system operation with load transfer to adjacent systems for reliability and security. Typical feeder locations for line regulators and pole top or substation capacitors have been added to illustrate changing topology effects. For any configuration, the “area of responsibility” of any regulator can change as does the effects of changing ratios on relaying for those areas.

Whereas Figure 14 illustrates the interconnection of feeders on a single sources distribution system, Figure 15 illustrates possible interconnection between otherwise single sourced distribution systems. Presently, such operating networks usually do NOT contain distribution line regulators on the tie feeders or DG.

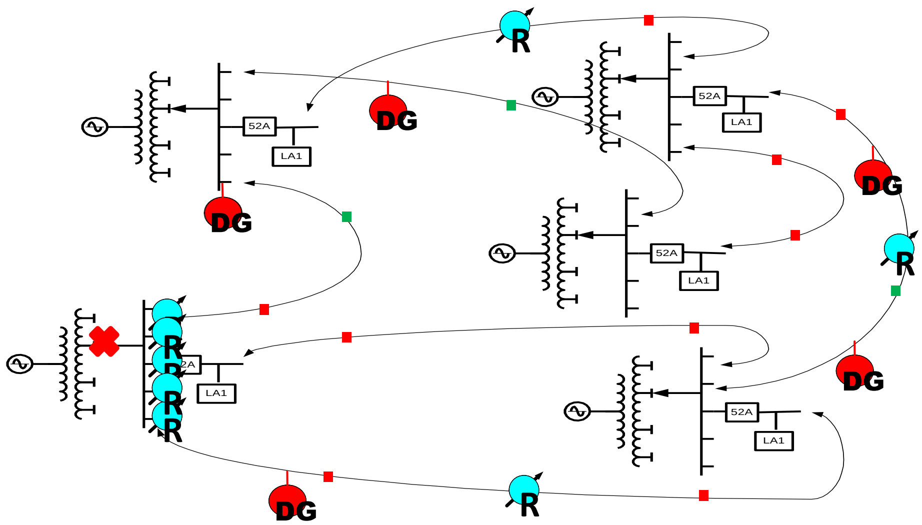

Figure 15. Interconnected distribution systems

***Paralleled transformer status, currents, voltages**
Figure 16 {repeated from figure 9} illustrates the problem of transformer primary side and secondary side protection coordination.

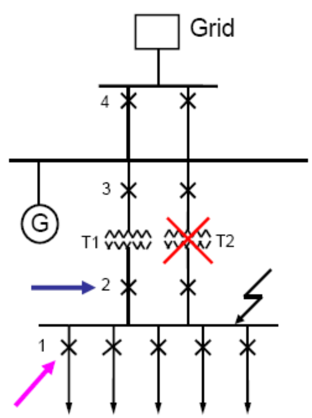

Figure 16. (Repeat of figure 9) Parallel transformer coordination

This information of loss of a transformer could also be supplied by the LTC control as loss of current. This could be used as the primary source of the data or a confirmation of another data source (breakers).

***Indication of transient high (fault?) current occurrence (downstream fault w or w/o tripoff?)**
Although the current transformers used for input to the controls are less than the quality needed to operate consistently with fault level current, their saturation could be used as an indication of a thru fault. This information, analyzed by a protective relay might be advantageous for fault location on a distribution circuit.

Some of the same system factors affect power system protection and relaying (PSR) and volt/var management (VVM) functions. One of the most important common factors is the “present” circuit (system) configuration. As distribution system circuit switches operate, for whatever reason, they change both function’s effectiveness and the “optimum” setting points for the resulting configuration. Another major contribution to a configuration change is any type of generation operated or changed on the circuit as well as an intertie connection between feeders or to another distribution system. These changes can be communicated to the necessary equipment for inclusion in the function operation by the Smart Grid communications.

16 APPLICATION FOR PEER-TO-PEER COMMUNICATIONS BETWEEN INTEGRATED VOLT/VAR COMPENSATION (IVVC) CONTROLS AND PROTECTIVE RELAYS

The primary function of capacitor controls and regulator/LTC controls is to regulate the voltage of the distribution grid while attempting to minimize losses through the reduction of reactive current. In the past these controls were typically operated in a local automatic mode. Any coordination between controls was performed via local settings including time delays and setpoints. With the advent of robust wireless communications, many are now adding communications from these devices to either a central SCADA system or distributed gateways located in the substations that originate the circuits.

When implementing a IVVC most utilities have focused on a Master/Slave relationship. There are several applications were peer-to-peer communications would add benefits, including communications to protective devices.

16.1 Protective Relays and LTC Controls

Many utilities use LTC controls at the substation to regulate the distribution busses at the substation. As the incoming voltage from the transmission grid drops, the LTC at the substation will attempt to raise the voltage so that this drop is not seen on the distribution side of the transformer. With a higher distribution voltage, the load on the distribution system will increase. During transmission instability events, this process can be detrimental to the transmission grid. If generation or transmission assets are lost and load remains constant, the voltage will start to collapse. With current LTC settings, the drop in transmission voltage will cause a drop in voltage on the distribution grid. The LTCs will respond to this drop by raising taps on the transformer to increase the voltage back to the desired range. This increase in voltage actually increases the load on the distribution grid and therefore also on the transmission grid. If the voltage on the transmission grid continues to drop a brownout or blackout condition can result.

To prevent this condition from happening, an under-voltage element on the transmission bus voltage can be used to actually drive the LTC into voltage reduction which will lower the load on the distribution grid and thus aid the voltage drop on the transmission grid. Most LTC controls do not monitor the high-side PTs but there are protective relays such as distance relays that can provide this function.

A distance relay that monitors the PTs on the high-side bus and that also has several under-voltage elements can be programmed to send a voltage reduction command to the LTC when the under-voltage element is active and release the voltage reduction command when the under-voltage element returns to normal.

To further reduce loading on the transmission grid, the LTC control, when in voltage reduction mode, could automatically monitor the power factor and send close commands to switch capacitor banks in so the power factor adjusted to the point of unity or to a slightly leading power factor. A slightly leading power factor at the transformer will cancel out the reactive losses in the transformer and allow the distribution grid to be Var neutral to the transmission grid. This will reduce loading on the transmission grid.

16.2 Recloser Controls and Line Regulator Controls

Most utilities operate the distribution feeders as radial. The voltage at the substation low-side will be regulated in one of three manners: (1) LTC transformers regulating the voltage on each bus, (2) single-phase or three-phase regulators regulating the voltage on each bus, or (3) single-phase regulators regulating the voltage on each feeder circuit. As the feeder circuits become longer and more heavily loaded, additional down-line regulation will be required. This regulation is achieved by adding additional single-phase regulators at various points, or adding capacitor banks (both fixed and/or switched) or a combination of both.

Figure 17 shows two distribution substations with LTC transformers. Each has a radial circuit leaving the substation and there is a normal-open tie point between the two circuits. Each circuit also has one set of line regulators at the mid-point of the circuit. These regulators monitor the voltage via a PT that is located on the load (L) bushing of the regulators. This is because regulators can only vary the voltage of the load side, not the source side. When regulators adjust the voltage by tapping up or down, only the voltage on the load–side changes. In this normal mode of operation the power flow is in the forward direction for both regulator, current flowing from the Source side of the regulator through the load (L) side of the regulator.

In this scheme the LTC is responsible for the voltage of the entire circuit (load points LA1 and LA2 for the LTC in substation A) and the line regulator is responsible for only the portion of the circuit from the L side of the regulators to the normal-open tie point (load point LA2).

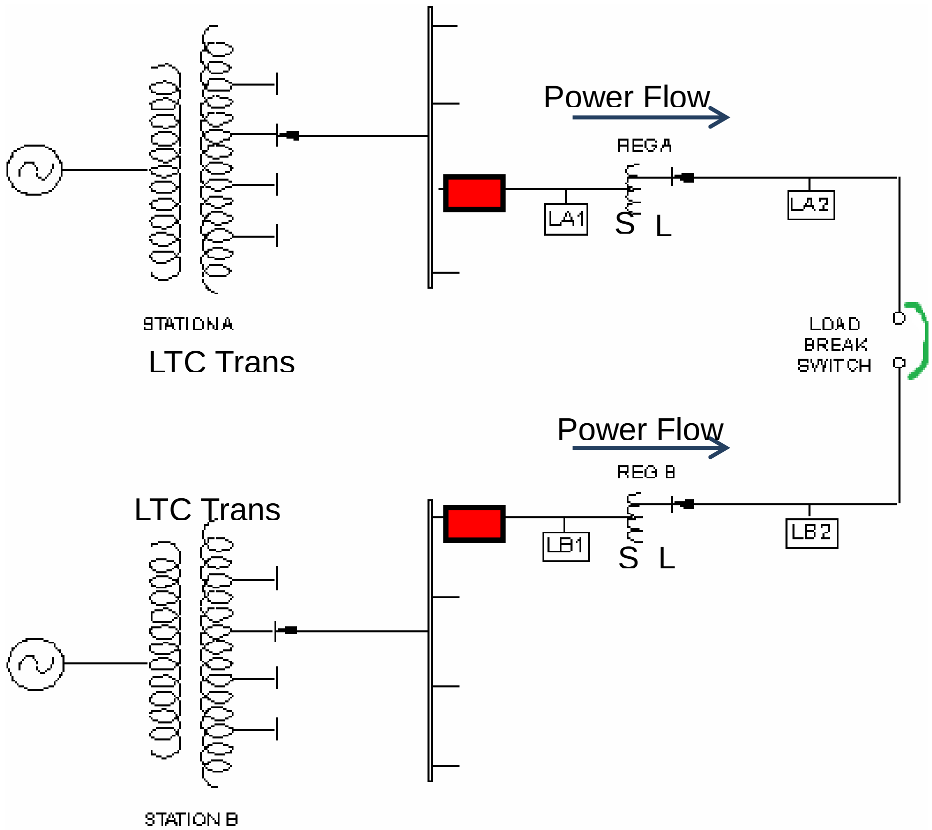

Figure 17. Distribution Substations with LTC

If the feeder in Substation A is taken out of service, the normal-open tie point can be closed in order to restore load to the circuit leaving substation A. This circuit is now being fed from substation B. Figure 18 depicts the new configuration and the effects it has on the line regulators.

The Zones of regulation are now as follows. The LTC in substation B is responsible for load centers LB1, LB2, LA2 and LA1. The Line regulator on the circuit leaving the feeder on substation B was originally responsible for only RB2 but now has added LA2 and LA1. The power direction of this regulator has stayed the same but the impedance of the circuit has increased as has the loading of the circuit as seen by the line regulator. The regulator that was at the mid-point of the circuit leaving substation A is now at the end of the circuit leaving substation B. Prior to the switching this regulator was responsible for LA2 and it is now responsible for LA1. Also notice that the power direction on this regulator has reversed. This means the load-side of the regulator or now the source-side. The voltage on the source-side does not change when a regulator operates and in this configuration the regulator is monitoring the source-side instead of the load-side. If the regulator control continues to use the PT input as the sense voltage a run-away condition will occur. Because the PT is on the side of the regulator now that does not change in voltage, once an “out of band” is detected the regulator will attempt to correct the voltage but will not detect a change and will continue to attempt to correct the voltage until it reaches a maximum or minimum tap. There are two ways to correct for this but both require the regulator to detect the reverse power flow. The first method is to have PTs on both sides of the regulator. In forward power mode the regulator uses the Load-

Side PT for sensing. On detection of reverse power the regulator control switches to the Source-Side (now Load-Side) PT for sensing. The second method does not require the additional PT but does require correct tap position into the control. On detection of reverse power, the regulator control calculates what the voltage would be on the new Load-Side by taking the measured now Source-Side PT and calculating what the voltage would be on the load-side using the tap position. Either method will work as long as the reverse power condition is caused by auto-sectionalizing or switching.

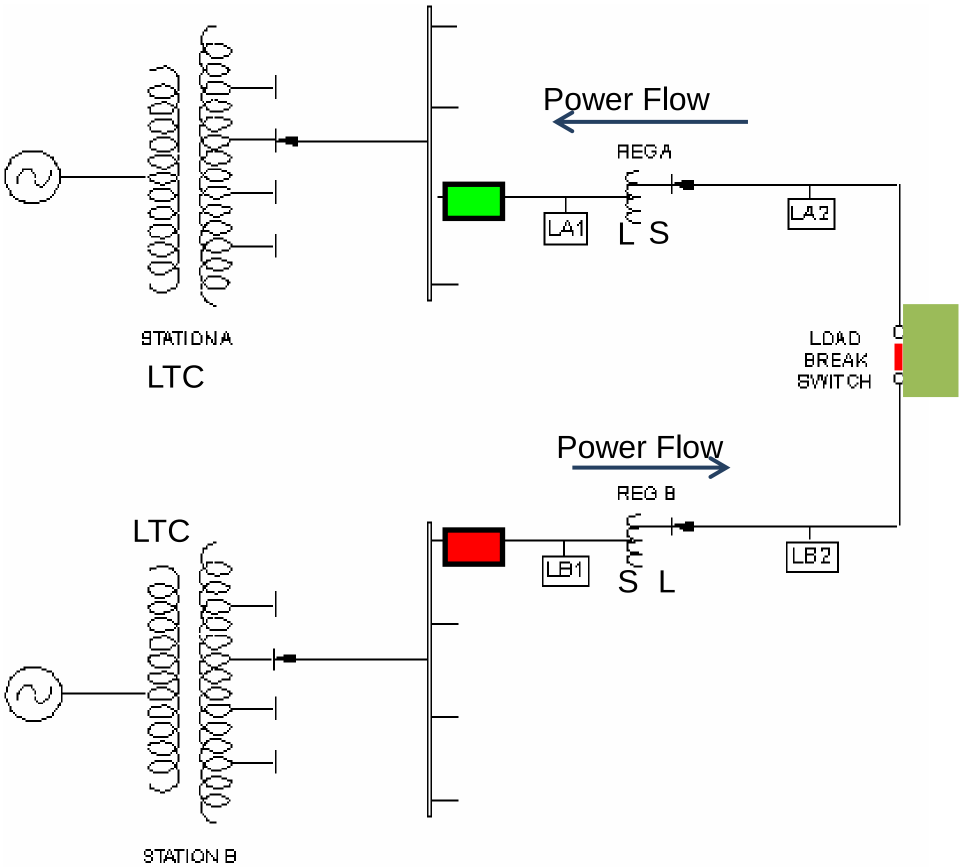

Figure 18. Distribution Substation with LTC in parallel condition

There is another condition on the distribution grid that can cause a down-line regulator control to detect reverse power and this condition is caused by distributed generation on the grid. Figure 19 shows the same circuits with the normal-open tie point open. Because it is open, reverse power can be caused by back feeding due to switching. Notice that a distributed generator is on the load-side of the regulator. If this generator is on-line and producing more power than the load requirements on the load-side of the regulator, power will flow in the reverse direction back towards the substation. In this case the Load-Side PT is still on the Load-Side of the regulator so it is not desirable for the control to switch PTs or calculate the sense voltage using the tap position as above but is desirable for it to continue to regulate using the sense voltage from the load-side PT.

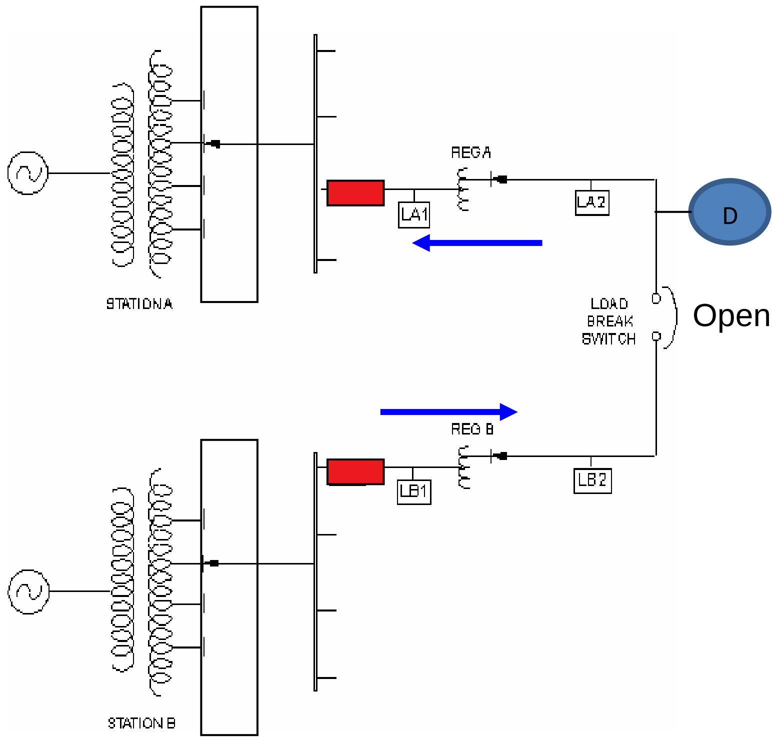

Figure 19. Distribution substation with parallel LTC removed with open tie.

The problem to be solved is why the reverse power condition is occurring. If it is due to switching it is desirable for the control to enter a mode "Regulate in Reverse", but if it is due to distributed generation it may be desirable for it to enter the DG mode. Unfortunately the control does not know why the reverse power condition is present. If there were a recloser control or RTU on the normal-open switch, this device could communicate that the normal-open point is closed. With this information the regulator control would enter the "Regulate in Reverse" mode. If reverse power is detected by the status of the normal-open switch is open, the control would enter the DG mode.

16.3 Protective Relays and LTC Controls with Paralleling of Transformers

In distribution substations sometimes transformers are operated in parallel. This means that the high-side and low-side busses for each transformer are operated as one bus by closing in bus-tie breakers. As long as the bus-tie breakers are closed, along with the transformer breakers, the controls usually operate in a parallel mode and attempt to regulate the voltage while minimizing circulating current or Var flow. If the bus-tie breaker opens, the transformers need to switch to an independent operation. Typically 52A contacts are wired from all tie-breakers into the individual controls to allow for detection of open tie breakers. These breaker contacts are already being monitored by protective relays. These protective relays can communicate the status of breakers to all controls in the scheme thus saving wiring and the need for additional breaker contacts.

16.4 Regulator Controls and Recloser Controls

A feeder circuit has several three-phase reclosers down-line from the feeder regulators. The feeder regulator controls may have Line Drop Compensation for the entire circuit. As the down-line reclosers trip to lockout condition for faults, the feeder circuit has a smaller impedance and less load. With this information the regulator controls can change setting groups to allow for different values of R and X.

In another situation, as seen in the reverse power Figures 17, 18 and 19, a feeder circuit may pick up additional load when it is tied to a portion of a neighboring feeder. In this case the circuit has added impedance and load. Again, changing setting groups could allow for a new value of R and X during these conditions. It may also be necessary to limit the tap movement of the regulator. Most regulators are rated in KVA so as the current increases, the KVA rating can be exceeded unless the percentage of regulation is reduced. This is accomplished by blocking the range of the regulator via the block on tap settings of the regulator control. In the normal mode with the normal-open tie point open, the regulator is allowed to operate over the entire range. When the normal-open tie is closed and the regulators pick up additional load, the setting group can be changed to allow for operation between taps -12 to 12 instead of -16 to 16 for example. This will allow the regulator to stay in service without overheating.

Finally, if the new load is heavy with motors, it may be advantageous to temporarily lengthen the time delay of the regulator for cold load pickup. This can also be accomplished if the recloser control informs the regulators control that a normal-open tie point just closed.

17 USING RELAY DATA TO DEFER NETWORK INVESTMENTS

Typically electricity distribution utilities have little visibility of medium voltage and low voltage (MV and LV) network assets as characterized in figure 20. Therefore to make investment decisions it is necessary to rely on network modeling that can estimate the peak loading distributed along feeders.

Network models may make certain assumptions and as such there is the potential for utilities to believe that reinforcement is necessary due to a feeder reaching its maximum capacity, when in fact spare capacity still exists. With the introduction of the Smart Grid however, there will be more protective relaying equipment deeper into the distribution network for functions such as reclosing and automatic restoration. There is the opportunity to leverage the inherent monitoring functions present in these devices to make more informed network investment decisions, and potentially defer investments that would have otherwise been considered necessary.

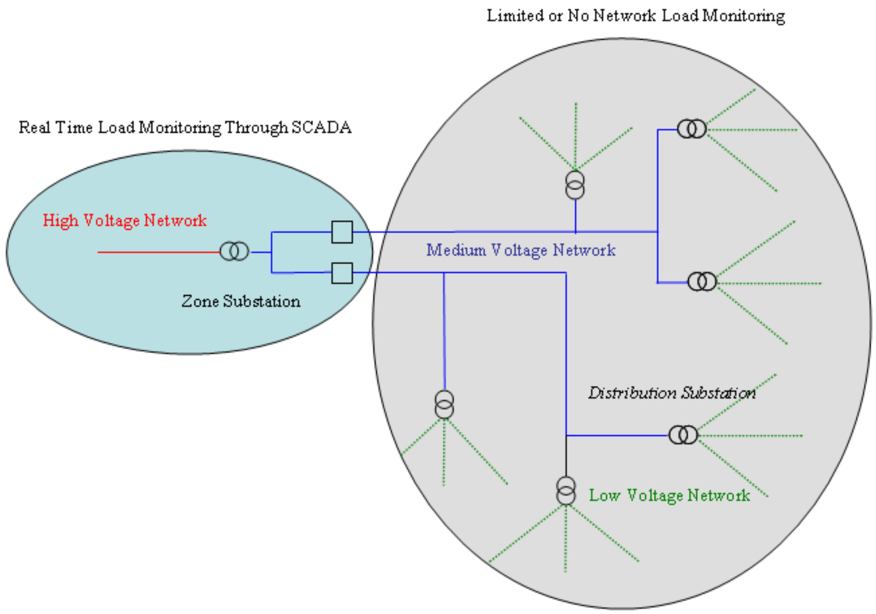

Figure 20. Typical extent of distribution network monitoring

How network modeling estimates feeder loading is demonstrated in figure 21. The total peak load is assumed to be spread across the distribution substations based on the installed capacity of each substation. For example, it is assumed that that the loading of T1 at feeder peak load is 385kVA (or 38%) of the total feeder peak loading, as 500kVA represents 38% of the total installed transformer capacity installed on the feeder.

This modeling technique obviously assumes that the utilization of every distribution substation is uniform across the whole feeder and also that the load profile of each distribution substation is the same. In reality both of these factors will vary, particularly if the feeder supplies a mixture of residential, industrial and commercial customers. This introduces inaccuracy and requires that certain safety margins be considered.

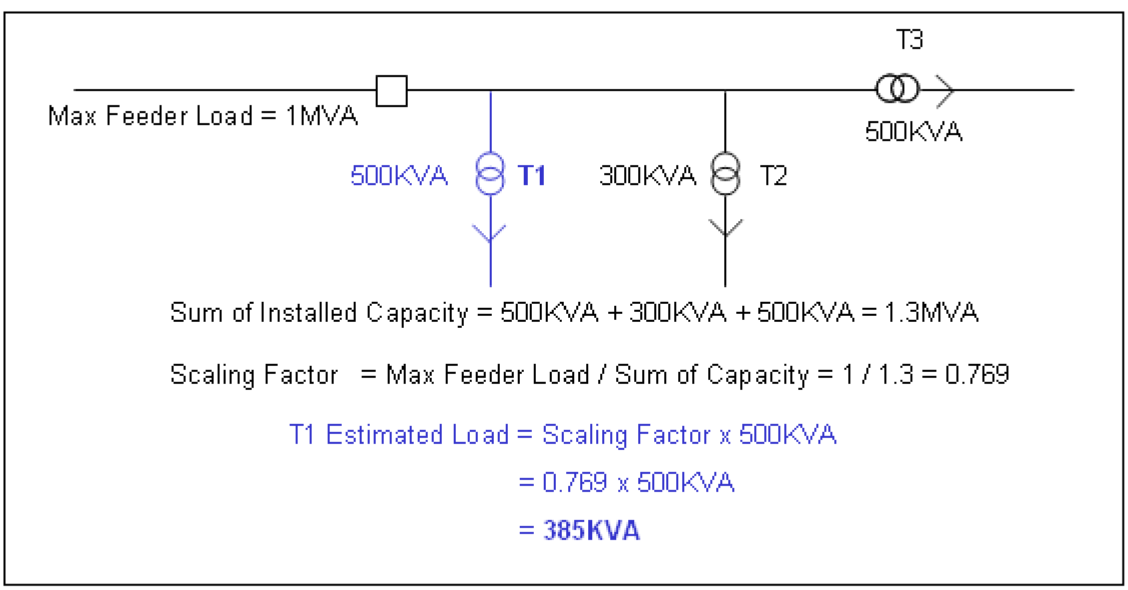

Figure 21. Typical MV feeder network model

This is demonstrated in figure 22, which shows an example of where a particular network model has inaccurately predicted loading on a feeder. Data from this mid-feeder relay when compared to the network model was shown to have peak loading 37% lower than what was estimated by the network model. Since it is this peak loading that generally triggers the need to install additional network capacity, this real world example shows that with availability of increased relay data there is the potential to defer network investments.

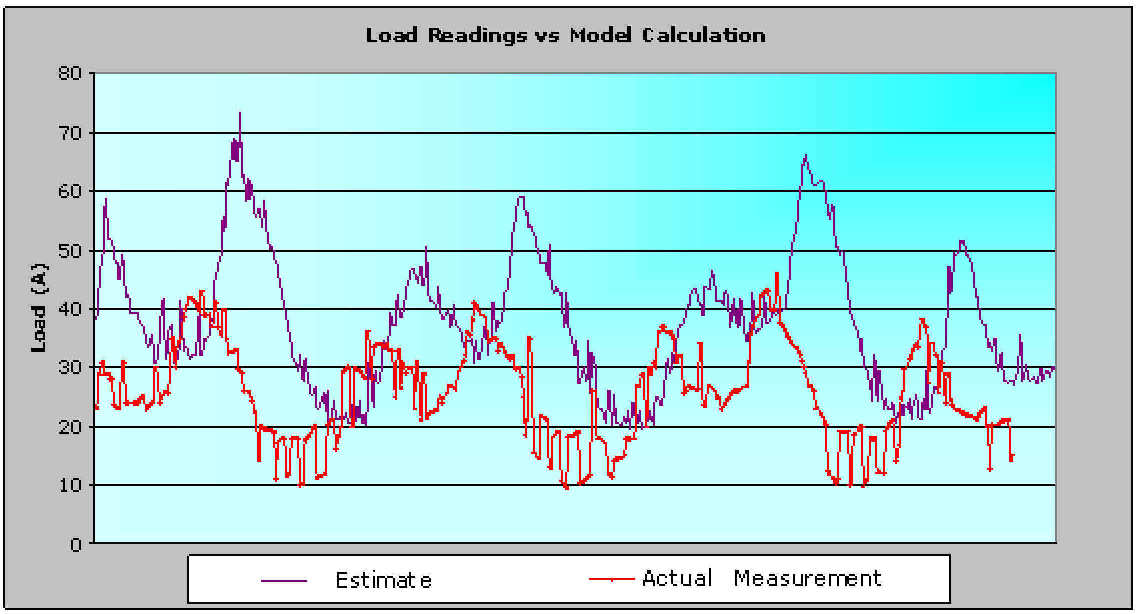

Figure 22. Example of actual network load readings vs model estimate

Another way in which investment deferral can be possible is by using this network data from protection relays to optimize the electrical configuration of feeders. For example, with reference to figure 23, if the feeder from substation one is at its maximum capacity and the network model were to estimate that the peak load at Distribution Substation A is 1MVA, then it will not be possible to transfer the load of this substation onto Feeder 2 as it exceeds the free capacity available and reinforcement to add capacity is required.

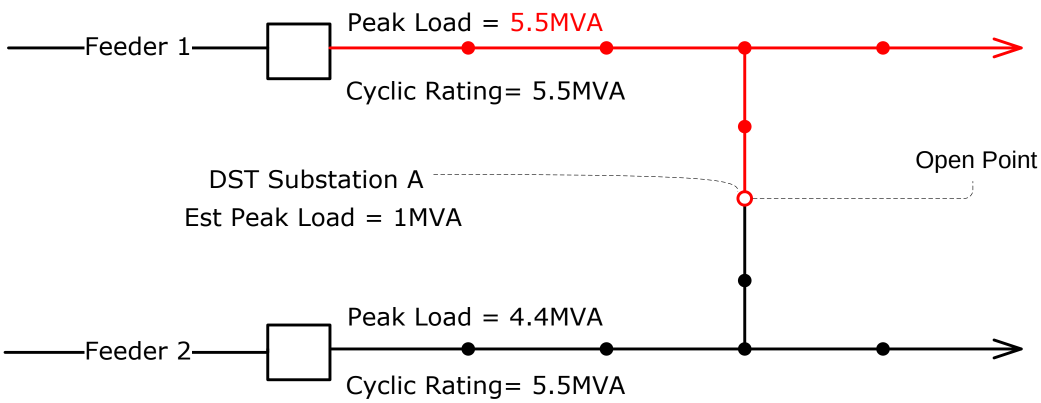

Figure 23. Overloaded feeder example

However if loading data were to be made available from a protection relay installed at Substation A it be might found as in the previous real-world example that the values estimated by the network model are over estimated. Figure 24 shows one possible scenario where Substation A's peak load is actually 0.94MVA not 1MVA and its load profile is significantly different to the load profile of Feeder. Therefore it actually will be possible to shift Substation A's load onto Feeder 2 rather than to carry out a network reinforcement, as shown in figure 25.

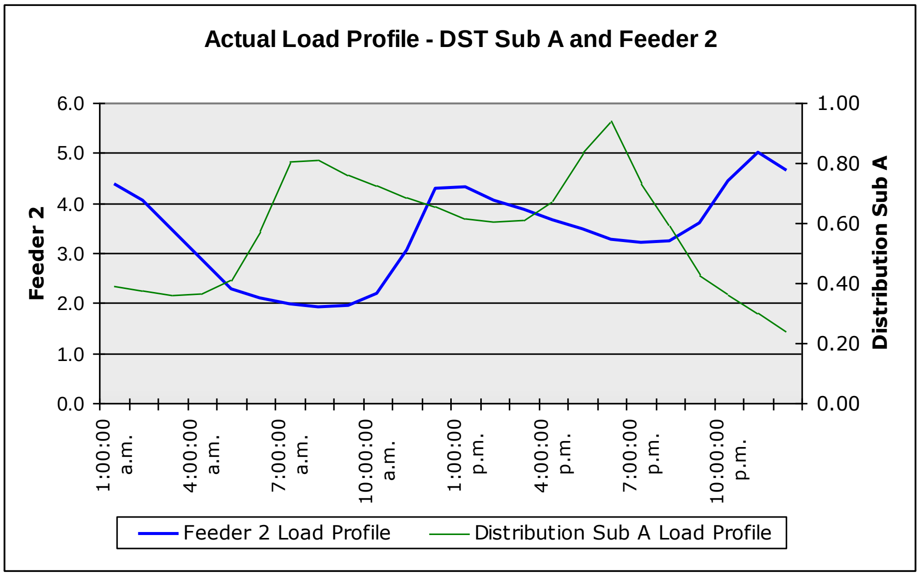

Figure 24. Feeder vs substation measured load profiles example

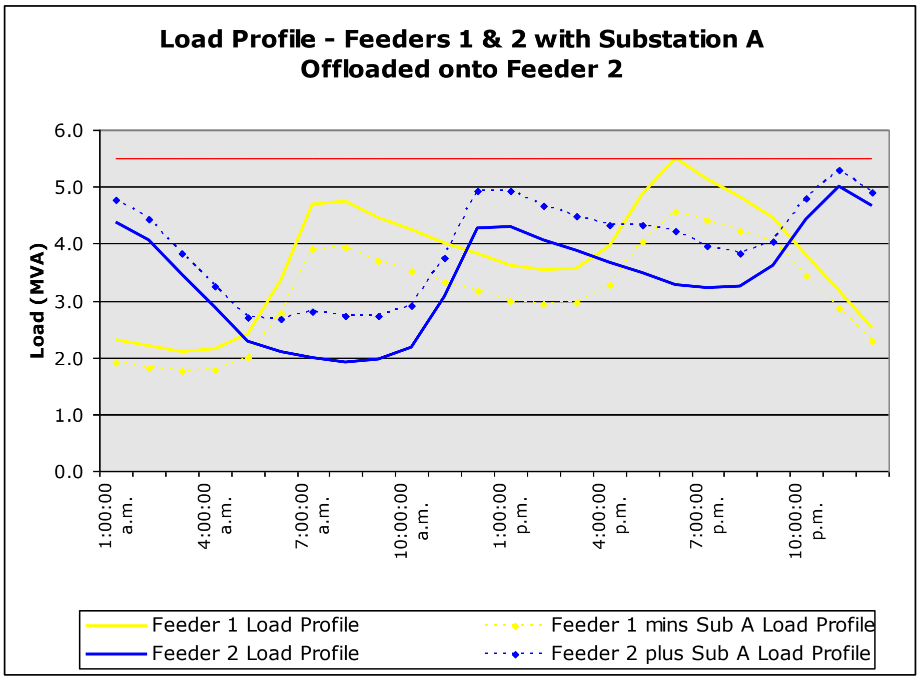

Figure 25. Resultant load profile: Substation A transferred to Feeder 2

18 DESIRED FEATURES AND FUNCTIONS FROM UTILITY USERS

Smart Grid functions, above protection, are considered an integral part of modern relays, but these may or may not include all functions deemed useful by electric utilities. Many Smart Grid functions are part of a SCADA system that may include relays or have separate elements. The following features and functions were compiled by a group of utility engineers.

Desired features include:

- Configurable programmable logic; using graphical logic equations. The ability to use graphical symbols is much preferred to simple "logical equations"
- Adaptive Relaying; using programmable logic or settings groups that are programmable based upon load and system conditions
- Manual Trip and Close push buttons on the relay
- Integrated Hot Line Tag control; both manual (local) and communications (remote) settable
- Configurable Pushbuttons; in order to implement relay logic or Alternate Settings Profiles (settings groups)
- Waveform Recording
- Hardened Product; surge immunity
- Local and Remote Serial Communication
- Cold Load Pickup
- Flexibility in overcurrent curves to match specialty and legacy devices
- Synchronized Phasor Measurement (PMU) functionality for data collection and as a part of a wide-area protection system..

Desired functions, which may require the above or other advanced features, include:

- Monitoring function of the logic elements in order to avoid mis-operation (e.g. the flashover logic in generation protection uses the breaker position as well as the voltage detection in the generator
- Logic which provides information about the availability of the scheme. Therefore if the generator is in service and the breaker is closed, the voltage is expected to be present. Otherwise, an alarm has to be sent showing loss of a logic element. See fig 26.

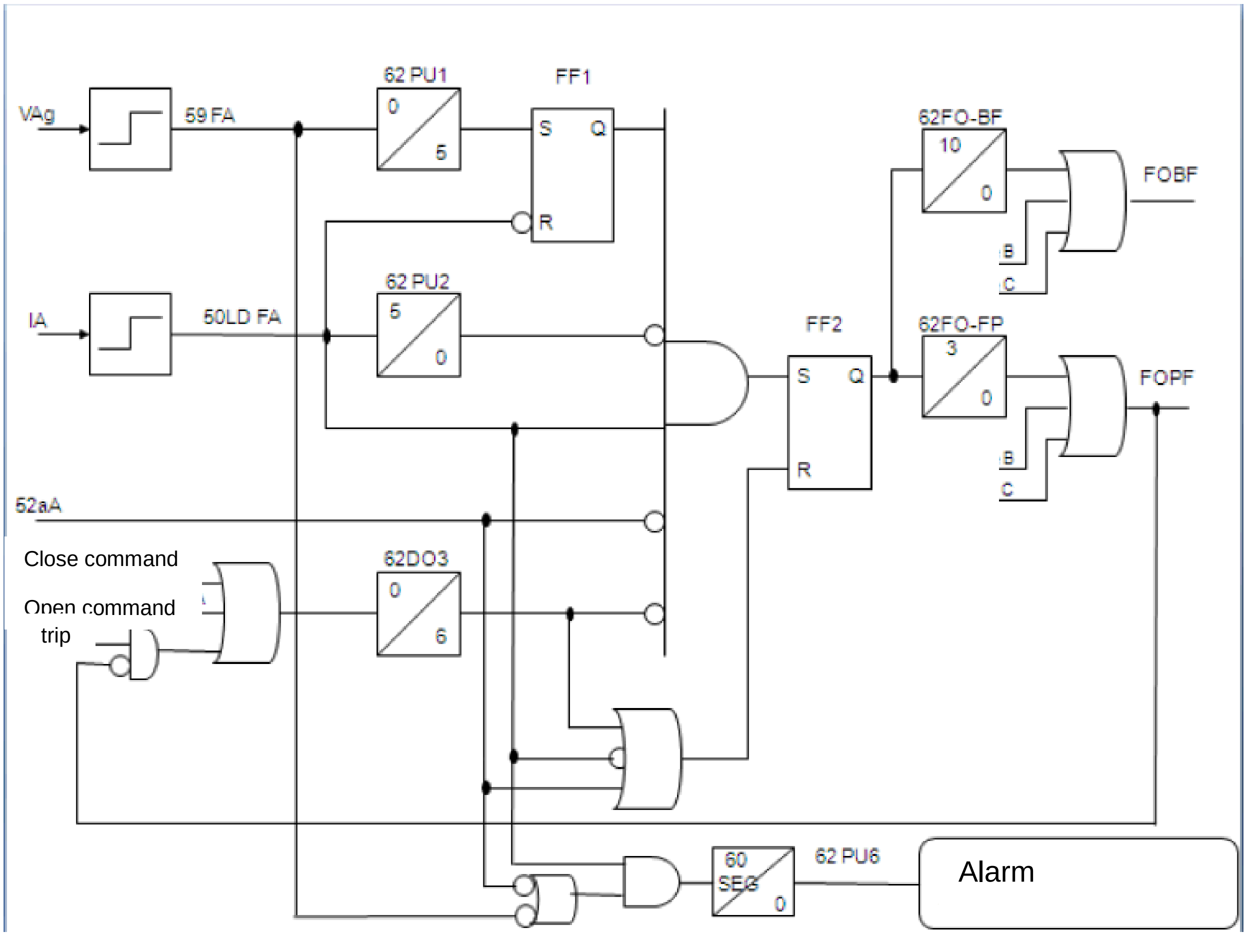

Figure 26. Flashover Logic for Phase A.

- Need for more information about how a Smart Grid can handle a solar storm, strategies, backup plans for restoration, etc.

- Monitoring information from primary equipment (e.g., trip coil current monitoring, CT / VT monitoring, Interconnection monitoring) and intelligent processing capability to determine the probability of failure and issue an alarm. If the condition persists the relay may adaptively reduce breaker failure times to avoid a catastrophic failure.

- Monitor the feeder for abnormalities that would most likely result in permanent outage, and thereby alarm and disable automatic reclosing, if the condition persists and results in a fault that is most likely permanent. Substation relays and feeder automation relays may also share this type of information to make smart decisions in clearing faults and restoring service to customers.

- Integration of cyber security initiatives as required to meet NERC CIP requirements such as for password control, access management, and implementation of message encryption.

- Improved accuracy fault location using information from relays, integrated with distribution automation devices (smart switches, fault indicators, smart meters) to quickly locate faults on the correct lateral.

19 FEATURES AND FUNCTIONS IDENTIFIED AS AVAILABLE IN PRDs

- Multiple setting groups (2-8 depending on manufacturer and model) are available in microprocessor relays. It is important to recognize that changing a relay setting group dynamically may involve "re-booting" time ranging up to many seconds. It may be preferable to use dynamic settings (available in many relays) that use a digital or measured value to change a setting to be more appropriate for changed conditions. This will involve no delay or loss of protection.
- Phasor Measurement Unit (PMU) functionality. Continuous transmission of IEEE C37.118 synchrophasors is available in many relays. Recognition of communication bandwidth required as well as processor burden is important, especially as higher sampling rates are available, one message per cycle (or faster).
- Primary equipment monitoring (circuit breaker, transformer) using voltages, currents, and temperature measurements as well as transducer inputs. Programmable algorithms with combinatorial logic are available for advanced condition monitoring such as loss of life or recommended maintenance.
- IED / Relay monitoring, such as self-test, processor temperature, processor burden. Communication status (serial or Ethernet) and automatic communication network switching may be available.
- Fault location for transmission and distribution systems.
- Multi-terminal protection, dynamically changed depending on primary configuration, for distance or differential protection.
- File transfer capability of settings, waveforms, and sequence of events in COMTRADE or proprietary formats.
- Multiple VT inputs for synchronizing across any possibility of circuit breaker connections, either with PMU function or direct synch-check.
- Programmable rate of change of measured value; applied to any measured or calculated input.
- Cyber-security features including password types, encrypted communications and access logging to meet NERC / CIP requirements.
- Single-Phase Tripping and Closing with Load Level Supervision
- Hot-Line Tag
- Ground Trip Blocking
- Incipient cable fault detection, to recognize patterns of voltage and current transients that indicate the cable insulation is failing.
- Equipment cycle counts.
- Line sag--conductor temperature--information (allowing dynamic system loading).
- Fault location, isolation and service restoration (FLISR).
- Automated Feeder Reconfiguration & Post-Restoration Load Management
- Redundant high-speed communications technology to maintain relay communications in the event of network failures. This may include:
    - Failover to a "healthy" communications channel on loss of the primary communications channel
    - Parallel Redundant Processing (PRP), which continuously communicates on two channels, and accepts the "first arrived" information packets (ignoring duplicate

but later-arriving packets on the alternate network connection. This technology provides zero-delay redundancy for the loss of a single network channel.

- Distributed-intelligence, located within interim-feeder devices, that can include the substation circuit breaker, automatically restores load to unfaulted feeder segments within alternate-source capacity limits. This operation can also involve automated post-fault sectionalizing by load-break switches provided they have a control/RTU that can indicate 3-phase overcurrent conditions. After restoration, the system continues to monitor load conditions and can prevent overloads by shifting or shedding load. Consequently, the system accepts a new “normal” (post-restoration) feeder configuration, and will continue to balance sources with loads.
- Automatically resolves unresponsive (communication loss or control failure) system members.
- Subcycle temporary closing
  - A non-intrusive means of determining if a fault is permanent or temporary without subjecting equipment and feeders to full fault duty.
- Intelligent Fuse-Saving
- Intentional high-speed tripping of source breakers to prevent fuse blowing for temporary faults. An enhancement is to avoid this “saving” when fault duties make it clear the fuse will be damaged regardless of breaker operation.
- Sensing accuracy - +/- 0.5%
- Volt/Var applications including state-estimation.
- Communication Enhanced Coordination (Adaptive Protection)
- Permits increased feeder sectionalizing using fault-interrupter without miss-coordination. Also determines appropriate TCC settings after automated feeder self-healing operations have introduced alternate source coordination requirements.
- Closed-Loop No-Outage Solution
- Applying dual source feeders with communications to provide high speed fault clearing with only a momentary dip in load voltage, typically less than 3 – 6 cycles and less than 20 – 50% voltage dip.

20 INTEROPERABILITY

Many of the functions and capabilities enumerated above are enabled by the inclusion of protocols and systems common across platforms. These include IEC61850 message and file transfer methods for exchange of information between PRDs and up to integration systems. Other common protocols include IEEE C37.118 for synchrophasor data transfer and COMTRADE format for event reporting. As the use of these interoperable protocols expands it becomes more expeditious to expand the use of the information available in the PRD to more functions.

21 CONCLUSIONS

This report lists many features, capabilities and functions of PRDs that go beyond traditional protection functions. The use of these functions will improve overall power system performance.

PRDs are generally designed such that these additional capabilities do not degrade the primary function of the device. Integration of the device would ensure that this philosophy is maintained through proper systems engineering.

Some of the goals of a Smart Grid are to improve the cost, resource and maintenance efficiency of the system by minimizing device count and duplication. By fully utilizing the capabilities of each device, the reductions of connection count, engineering time requirements, and failure rates all are possible. Integrating the functionality of multi-function PRDs within different Smart Grid applications will help achieve these goals. Organizational challenges are added as these functions increase. These organizational limitations can impact the cost effectiveness of advanced devices' integration.

This report is complementary to the H2 report, "Protective Relay Applications using the Smart Grid Communication Infrastructure."

22 BIBLIOGRAPHY

1. "Driving Factors in the Move Towards Smartgrids" European Smartgrids Technology Platform: Vision and Strategy. European Commission. p. 9. ISBN 92-79-01414-5. . *Smartgrids Advisory Council. .* [Online] http://www.smartgrids.eu/documents/vision.pdf.
2. National Energy Technology Laboratory (2007-07-27) (pdf). A Vision for the Modern Grid. United States Department of Energy. p. 5. Retrieved 2008-11-27. [Online] http://www.netl.doe.gov/moderngrid/docs/A%20Vision%20for%20the%20Modern%20Grid_Final_v1_0.pdf.
3. "Toward a Smarter Grid ABB's Vision for the Power System of the Future". *GridWise Alliance .* [Online] http://www.gridwise.org/documents/090709ABBpaper_Smarter%20Grid.pdf.
4. **Anderson, Roger and A. Boulanger, J. A. Johnson and A. Kressner.** *p 333. Computer-Aided Lean Management for the Energy Industry.* (2008 ISBN 978-1-59370-157-4).
5. **Yilu Liu, Lamine Mili, Jaime De La Ree, Reynaldo Francisco Nuqui, Reynaldo Francisco Nuqui.** *"State Estimation and Voltage Security Monitoring Using Synchronized Phasor Measurement" (pdf).* (2001-07-12).
6. **Mazza, Patrick.** Powering Up the Smart Grid: A Northwest Initiative for Job Creation, Energy Security, and Clean, Affordable Electricity.]. Climate Solutions. p. 7. . [Online] 2005-04-27. [http://fortress.wa.gov/wutc/home/webdocs.nsf/de53b07997d108ea882563b50072c5b3/bc3ced6bb5f4cf29882570200083aaa3/$FILE/Powering%20Up%20Smart%20Grid%20report.doc.
7. **Nanjing Nari-Relays Electric Co., Ltd. .** Wide Area Protection System for Stability. . [Online] 2008-12-12. http://www.nari-relays.com/en/files/Wide%20Area%20Protection%20System%20for%20Stability.pdf.
8. **Zhao, Jinquan, et al.** *On-Line Voltage Stability Monitoring and Control (VSMC) System in Fujian power grid.* s.l. : Proceedings, Power Engineering Society General Meeting, (2007-06-24).
9. Cisco Outlines Strategy for Highly Secure, 'Smart Grid' Infrastructure. [Online] http://newsroom.cisco.com/dlls/2009/prod_051809.html.
10. Why the Smart Grid must be based on IP standards. [Online] http://blog.ds2.es/ds2blog/2009/05/why-smart-grid-must-use-ip-standards.html.
11. **IEEE.** IEEE P2030 Official Website. [Online] http://grouper.ieee.org/groups/scc21/2030/2030_index.html.
12. **EETimes.com:.** IEEE conference drive Smart Grids - P2030 aims to develop a guide to grid standards. [Online] http://www.eetimes.com/news/design/showArticle.jhtml?articleID=215901223.
13. **GMT Research 2009 by DAVID J. LEEDS.** "THE SMART GRID IN 2010: MARKET SEGMENTS, APPLICATIONS AND INDUSTRY PLAYERS". *GridWise Alliance website.* [Online] http://www.gridwise.org/documents/090901The%20Smart%20Grid%20in%202010%20GTM%20Research(revisedSept09).pdf; .
14. *User guide for the application of monitoring and diagnostic techniques for switching equipment for rated voltages of 72.5 kV and above.* s.l. : Cigré, 2000.
15. *Proactive maintenance can yield more than a 10-fold savings over conventional predictive/preventive maintenance program.* **Fitch, J. C.** s.l. : Diagentics Inc., 1995.
16. *IEC 61850 also outside the substation for the whole electrical power system.* **Schwarz, Karlheinz.** s.l. : 15th Power Systems Computation Conference PSCC, Session 13, Paper 6. , 2005.
17. *IEC 61850 as a flexible tool for electrical systems monitoring.* **Lloret, Pau, et al,.** Barcelona, Spain : 9th International Conference Electrical Power Quality and Utilisation, October 2007.
18. *COMTRADE: A new standard for common format for transient data exchange.* s.l. : IEEE Transactions on Power Delivery, Vol. 7, No. 4 - IEEE/PSRC, October 1992.

19. **PSRC.** *IEEE Guide for Determining Fault Location on AC Transmission and Distribution Lines.* s.l. : IEEE/PSRC, 2004. C37.114.
20. *"A new fault location technique for two- and three-terminal lines,".* **A. Girgis, D. Hart, and W. Peterson,.** s.l. : IEEE Trans. Power Delivery, vol. 7-1, pp. 98-107, January 1992.
21. *User guide for the application of monitoring and diagnostic techniques for switching equipment for rated voltages of 72.5 kV and above.* s.l. : Cigré, 2000.
22. *COMTRADE: A new standard for common format for transient data exchange.* s.l. : IEEE/PSRC, IEEE Transactions on Power Delivery, Vol. 7, No. 4 , October 1992.