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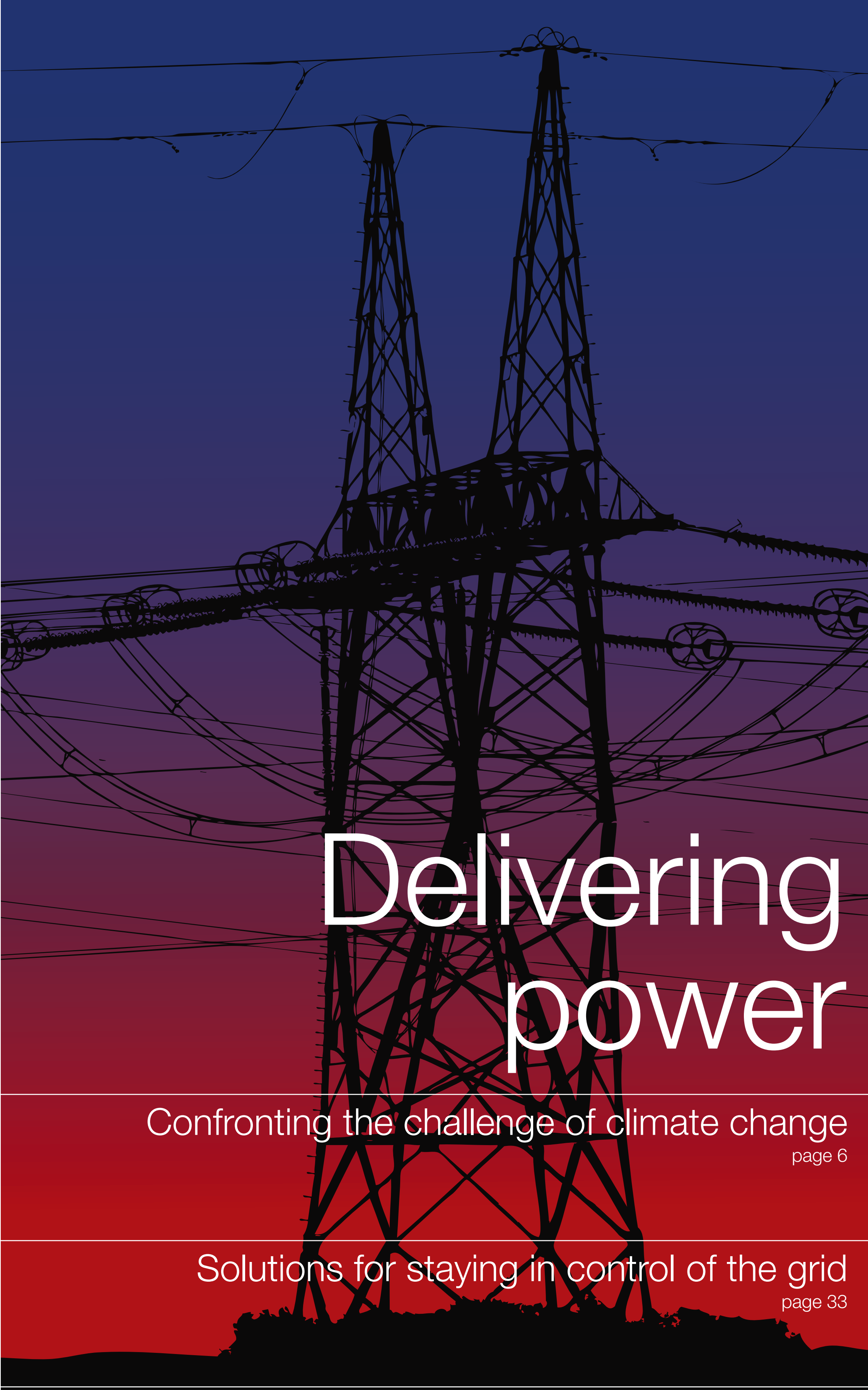
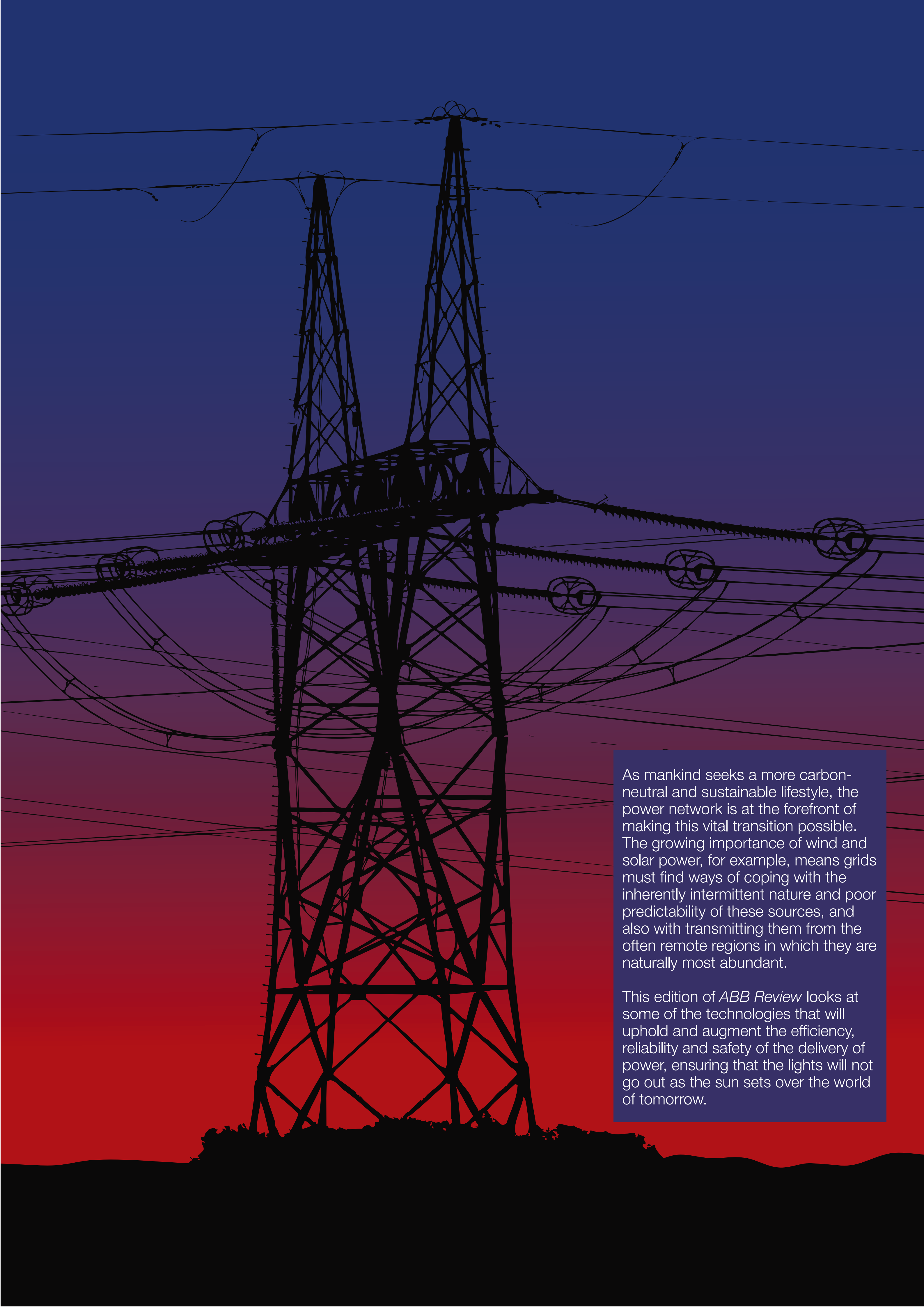


Delivering power

ABB



As mankind seeks a more carbon-neutral and sustainable lifestyle, the power network is at the forefront of making this vital transition possible. The growing importance of wind and solar power, for example, means grids must find ways of coping with the inherently intermittent nature and poor predictability of these sources, and also with transmitting them from the often remote regions in which they are naturally most abundant.

This edition of *ABB Review* looks at some of the technologies that will uphold and augment the efficiency, reliability and safety of the delivery of power, ensuring that the lights will not go out as the sun sets over the world of tomorrow.

Shaping tomorrow's grid

We have come to take for granted that practically every room in every building has electric power outlets and electric light. But it is not only this ubiquitous coverage that sets the electrical grid apart from any other man-made service (except maybe radio-based communication), but it is also its extremely high availability: We expect the lights to turn on whenever we want them to. From the point of view of the grid operators, this means that the supply must strictly follow the demand.

The functioning of the electrical network is undergoing a fundamental paradigm shift. One driver of this is the increased use of alternative energies such as wind and solar, whose supply is intermittent and difficult to predict; and much of whose generation is located in regions that are distant from the main load centers, and where the traditional grid infrastructure is often too weak to handle the additional power flows. Furthermore, consumers are increasingly choosing the source of their power, and hence expecting networks to be able to transmit it over longer distances.

This grid of tomorrow is often referred to as the "smart grid." The key technological enablers of this transition are progress in the power electronics and automation domains. In this future grid, there will no longer be a one-way relationship with generation following consumption, but rather a two-way interaction with such measures as energy storage or supply-dependent operation of devices permitting a more ecological and economic utilization of generation and transmission infrastructure. *ABB Review* intends to dedicate an upcoming edition to the topic of smart grids, and is hence giving it only partial coverage here. Many of the technologies addressed are, however, directly or indirectly relevant to this theme.

If the grid is to handle greater power flows, technologies are required to underpin its stability. Besides the additional transmission capacity it provides in its own right, ABB's HVDC Light® adds stability and controllability to existing corridors, and can actually enhance their overall transmission capacity by more than the nominally installed additional power.

One important aspect of the grid of tomorrow will be a greatly enhanced controllability assured by a large number of measuring and monitoring devices along with the corresponding actuators. These can, for example, make the grid self-healing by localizing and mitigating disturbances as they occur. Over longer periods, they can monitor individual items of equipment and so help schedule maintenance tasks. In contingencies (for example after a storm) they can pinpoint damage and support the deployment of repair crews, considerably shortening the time required to restore normal operations. Having to process a large number of data feeds can, however, also challenge a control system and risk causing a "data tsunami" in which the most relevant information is lost. Equally important as the measurements themselves is a strategy to handle these and convert data to information at as low a level as possible. Several articles in this edition of *ABB Review* discuss these and related aspects.

Further energy-related articles look at the management of a liquefied natural gas (LNG) supply from the dockside to the distribution network, and also at the importance of establishing standards for motor efficiency. The latter will give customers more transparency in relation to assessing the life-cycle costs and carbon footprint of their equipment.

This edition's history article looks at ABB's 100 years of experience in the manufacturing of bushings, and how these have evolved to handle ever-higher voltages.

I trust that this edition of *ABB Review* will give you fresh insight into the functioning of today's and tomorrow's energy supply, and illustrate ABB's commitment toward making this even more efficient, reliable and safe.

Enjoy your reading.

Peter Terwiesch
Chief Technology Officer
ABB Ltd.

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Perpetual pioneering

Challenges and opportunities aplenty

How to meet the challenge of climate change

Anders H. Nordstrom

It's been called "a disaster in slow-motion." The impacts are already severe but the real threat is probably a couple of generations away. Scientists have been gathering evidence for decades but, until recently, societies have hesitated to take action. Today climate change is on everybody's lips and governments all over the world are taking measures to curb greenhouse gas emissions. However, the challenge is huge: The world is like a super tanker heading toward the rocks and a quick but difficult turnaround is badly needed.

The mitigation of climate change is a long-term issue that calls for significant changes in the way industry and society at large produce and use energy and electricity. For its part, ABB has been and will continue to be committed to helping its customers use energy more efficiently and reduce their environmental impact through a broad array of products, systems and services. It has a two-year rolling target to reduce its use of energy per manufactured unit by 5 percent.

It is well established that the world is getting warmer. Meteorologists have observed an increase in the average global surface temperature of 0.74 ± 0.18 °C (1.33 ± 0.32 °F) during the last century. At the same time the CO_2 concentration in the atmosphere has risen from 280 parts per million (ppm) before the industrial revolution to nearly 390 ppm today. This by far exceeds the natural CO_2 levels in the atmosphere over the last 650,000 years! This increase is entirely the result of human activity caused mainly by the burning of fossil fuels, and the rise continues at a rate of 2 ppm per year.

The Intergovernmental Panel on Climate Change[1] (IPCC) has concluded that most of the observed temperature increases since the middle of the 20th century is very likely due to the rise in greenhouse gas concentrations. This conclusion is based on thousands of studies made by scientists in different disciplines all over the world.

Climate history and predictions

In various ways, nature has kept records of its own climate history and scientists have developed methods to study and interpret these data. For example, historical temperatures can be deduced from tree-ring widths and coral growth, and valuable climate data are hidden in the Arctic and Antarctic ice layers. Also, by studying the composition of air in bubbles deep down in the ice, the CO_2 concentration at a specific time can be determined. The average temperature of the period in question can be determined by measuring the ratio between different isotopes of oxygen in the ice. Mass spectroscopy allows very accurate determination of this ratio and may even resolve seasonal variations. Up to now, ice-core studies have revealed information about several hundred thousand years of climate history.

From the mid-19th century, instrumental temperature records have been used to determine the average global surface temperature. Regular measurements of CO_2 concentration in the atmosphere started in 1958 in Hawaii and accumulated data show an upward trend in CO_2 concentration and characteristic seasonal variations 1.

> Over the last century, meteorologists have observed an increase in the average global surface temperature of 0.74 °C while the CO_2 concentration in the atmosphere has risen to nearly 390 ppm.

Advanced computer models are used to project future climate change. The models attempt to cover as many relevant physical processes as possible and combine coupled general circulation models for the atmosphere and oceans with those for ice on land and sea. By applying such models to a number of different emissions scenarios, the IPCC projects an increase in average global surface warming of between 1.1 and 6.4 °C by the end of this century!

The mitigation challenge

To minimize the risk of the dangers of climate change, the European Union (EU) and others have long advocated that any increase in global temperatures should be kept below 2 °C relative to pre-industrial temperatures. This will require a stabilization of greenhouse-gas concentration in the atmosphere at well below 450 ppm CO_2-equivalent.[2]

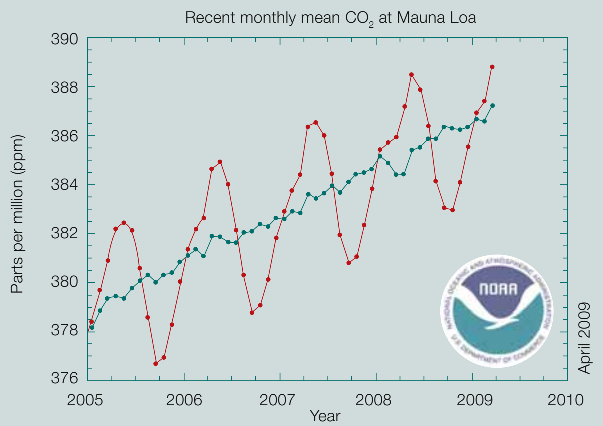
With current global emissions trends, the 450 ppm goal is challenging. In a business-as-usual scenario, the International Energy Agency (IEA) predicts energy-related greenhouse gas emissions to rise strongly in the foreseeable future: By 2030, global primary energy demand will be 45 percent higher than today, with 80 percent of the energy mix still based on fossil fuels. Ninety-seven percent of the increase will take place in non-OECD countries. The IEA has warned that

Footnotes

1) National science academies in major countries express support for IPCC's results and conclusions.

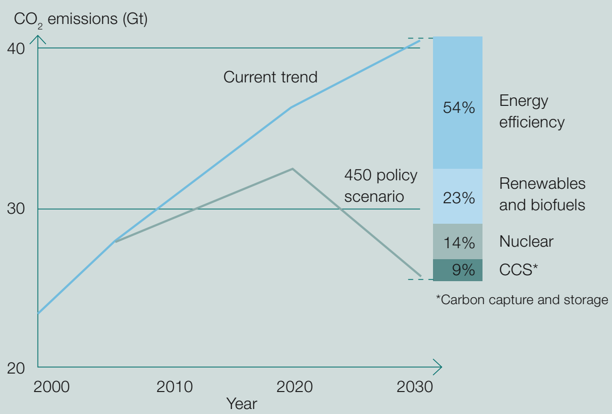
2) Today's CO_2-equivalent level is already around 445 ppm when five other anthropogenic greenhouse gases are included. However, fine particles in the atmosphere and ozone in the troposphere are believed to largely offset this additional heating contribution, resulting in an effective level of CO_2 concentration of around 387 ppm.

1 CO_2 concentrations continue to increase



Source: http://www.esrl.noaa.gov/gmd/ccgg/trends/

2 IEA emission scenarios



Source: IEA, WEO 2008

Energy and environment

this scenario will lead to severe and irreversible damage to the climate.

Securing a global supply of affordable energy to meet ever-increasing demands without generating excessive amounts of greenhouse gases is a huge challenge.

McKinsey & Company has found a potential exists to reduce greenhouse-gas emissions by 70 percent by 2030 and that any increase in temperature can be kept below 2 °C.

The IEA has developed and analyzed a scenario that fulfills the 450 ppm stabilization target. This scenario requires strong and concerted action to curb the growing greenhouse gas emissions. It relies on successful international climate negotiations where all countries, especially major emitters, commit to cutting emissions. According to the IEA, even if the OECD countries were to reduce their emissions to zero, they cannot achieve the 450 ppm target by themselves.

The scenario predicts a 22 percent growth in primary energy demand until 2030, with 67 percent of the energy mix coming from fossil fuels alone.[3] Energy-related CO_2 emissions are cut by 37 percent compared with the business-as-usual scenario. As much as 54 percent of the savings come from energy-efficiency measures, while renewable energy and biofuels contribute 23 percent. Carbon capture and storage (CCS) and nuclear power are also important instruments in cutting emissions 2.

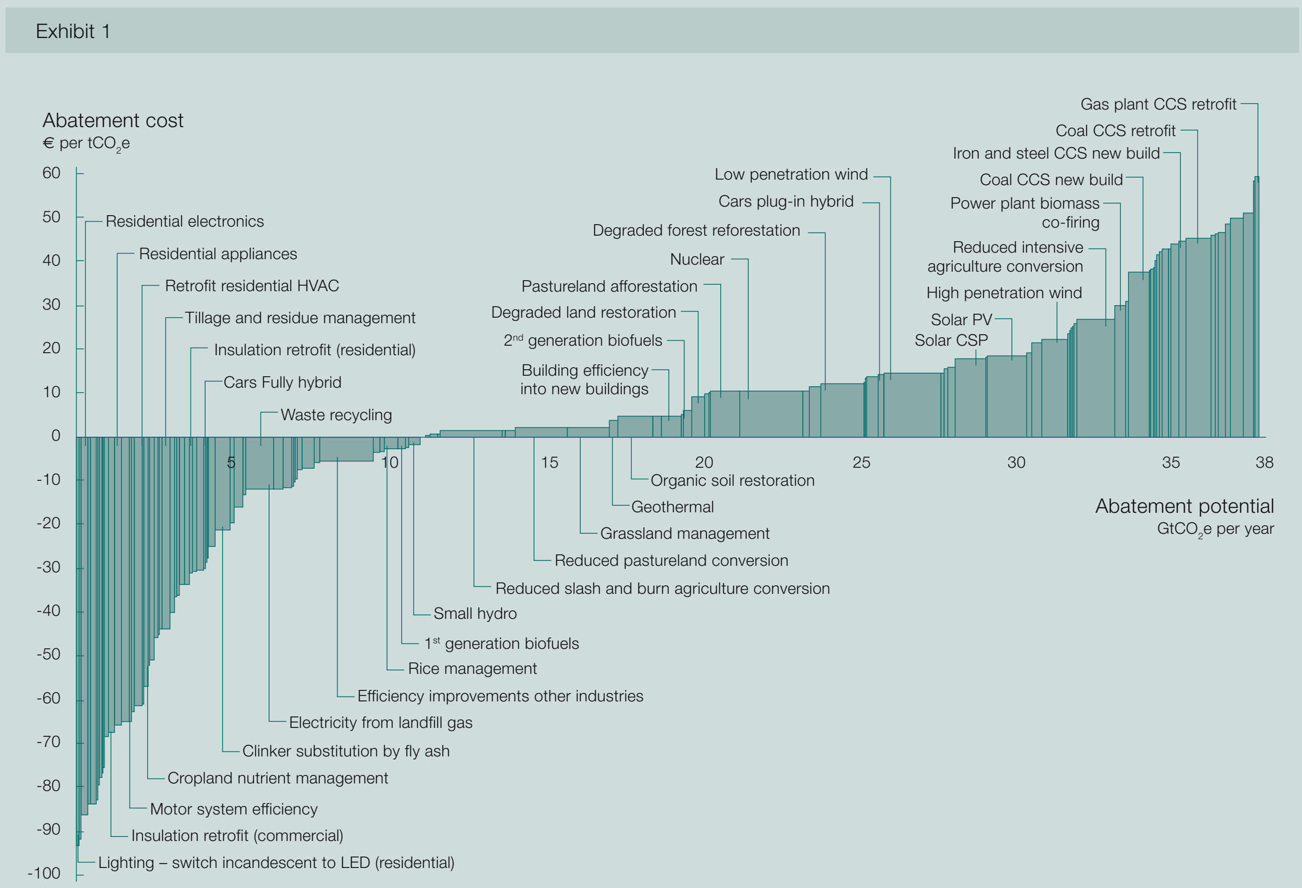
Transforming the energy system will require large investments: The IEA estimates an average cost of 0.55 percent of annual world GDP up to 2030. At the same time, improved efficiency levels will reduce both operational costs and energy bills.

McKinsey & Company has made an in-depth study of emissions reduction potential and cost of more than 200 technologies in 10 different sectors, covering all relevant sources of emissions (not only energy-related) in 21 different regions around the world. The company has found that a potential exists to reduce greenhouse-gas emissions by 70 percent by 2030 as compared to business-as-usual, and that any increase in temperature can

Footnote

[3] Even in this scenario, fossil fuels maintain a dominating role for a considerable period of time.

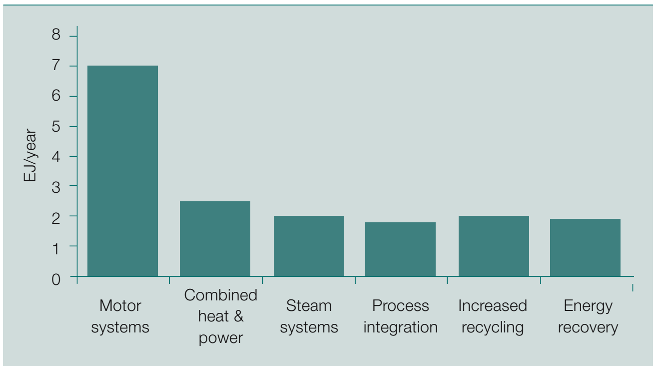
3 McKinsey's global GHG abatement cost curve v2.0



Note: The curve presents an estimate of the maximum potential of all technical GHG abatement measures below €60 per tCO_2e if each lever was pursued aggressively. It is not a forecast of what role different abatement measures and technologies will play.
Source: McKinsey & Company

be kept below 2°C. However, it is a huge challenge to capture enough of this potential since success relies on the implementation of almost all identified abatement opportunities. McKinsey has found that a 10-year delay in taking action against emissions would make it impossible to limit the temperature rise to 2°C. The annual mitigation cost by 2030 is estimated at 1 percent of the forecasted global GDP. In agreement with the IEA, it has found that future energy savings compensate for much of the upfront investment 3.

4 Energy-saving potential in the manufacturing industry: Motor systems offer huge opportunities (data from an IEA report).



Energy efficiency

In many countries, energy efficiency increased considerably after the oil crisis in the 1970s. Today, the production of a unit of GDP in developed countries requires 30 percent less energy than it did 1973. This is a result of productivity improvements and products that are more energy efficient and more intelligent.

Energy efficiency improvements decreased during the 1990s because energy prices were low and stable, and considerable reductions in energy intensity had already been achieved. In cases where the cost of energy represents a minor part of a company's overall costs, it is easily forgotten when optimizing manufacturing processes and product performance.

Today energy efficiency is high on many agendas and its key role in the mitigation of climate change is universally recognized.

The potential to save energy is everywhere in society: In the power sector, opportunities exist in the chain that connects generation to consumption. Energy use can be cut in commercial and residential buildings by providing better insulation and by controlling heating and cooling. Improved car fuel efficiency can also make a considerable difference.

Huge savings can also be achieved in industry. According to a report from the IEA, almost a third of the world's energy consumption and 36 percent of CO_2 emissions are due to manufacturing. Industrial energy use has increased strongly over the last 25 years and about 80 percent of the growth has occurred in China. The IEA has identified potential savings of between 25 to 37 EJ[4] (Exajoules) per year in the manufacturing industry if best practices and proven technologies[5] are used. This corresponds to a reduction of 7 to 12 percent of present global CO_2 emissions.

The European Union is a keen supporter of the UN process to manage climate change and has been implementing climate policies and regulations for some time.

Electrical motor systems offer the largest savings opportunity in the manufacturing industry. Optimizing motor systems can achieve yearly savings of between 6 and 8 EJ, which is equivalent a quarter of the world's total nuclear power production 4. The use of high-efficiency motors, variable-speed drives to control motor speed and adequate motor protection to permit downscaling of motor sizes are some of the means of achieving these savings.

Negotiations and climate policies

This year, governments around the world are busy preparing for COP-15, the United Nations (UN) climate conference, which will be held in Copenhagen in December. According to the Bali Action Plan established at COP-13 two years ago, governments are destined to agree on a new and ambitious global treaty to succeed the Kyoto agreement by 2012.

Key points that will be addressed at COP-15 include:

- The amount of emissions reduction that developed countries must commit to and how this is to be financed.
- The reasonable mitigation actions for developing countries, especially China and India.
- The possibility of reaching a credible agreement on the stabilization of greenhouse-gas concentrations in the atmosphere at 450 ppm CO_2-equivalent or less.

The success of COP-15 depends on finding acceptable compromises on these issues and on reaching an agreement. However, even without a new global agreement, countries and regions are already taking action by implementing policies and regulations to curb emissions.

The European Union (EU) is a keen supporter of the UN process to manage climate change and has been implementing climate policies and regulations for some time. Its main tool is the cap-and-trade system, EU ETS, which puts an absolute cap on 50 percent of all emissions in the EU. Twelve thousand industries and power plants within the EU have obligations in the system. The EU's 20/20/20 plan sets out targets for 2020, including:

- Cutting CO_2 emissions by 20 percent compared with levels in the 1990s. This figure will increase to 30 percent if a global agreement can be reached.
- Increasing the share of renewables in the energy mix to 20 percent.
- Cutting primary energy use by 20 percent through efficiency measures.

Footnotes

[4] 1 Exajoule (EJ) = 10^{18} joules

[5] An 18 to 26 percent increase in energy efficiency

Energy and environment

The US administration has indicated that it aims for an agreement in Copenhagen, including binding commitments to reduce emissions. The administration's New Energy for America plan aims to:

- Cut emissions to the levels seen in the 1990s by 2020 and by 80 percent by 2050.
- Have a million plug-in hybrid cars on the road by 2015.
- Ensure that by 2012 10 percent of power comes from renewable; this figure will increase to 25 percent by 2025.
- Introduce an economy-wide cap-and-trade program.

China embraces the principle of "common but differentiated responsibilities" established in the Kyoto protocol, which says that developed countries should take the lead in reducing greenhouse-gas emissions as well as providing financial and technical support to developing countries. However, some signs indicate that China may be ready to relax its resistance against controlling its emissions and is interested in reaching an agreement in Copenhagen. China launched its National Climate Change Program two years ago, which includes the challenging target of cutting energy intensity by 20 percent by 2010. China also aims at doubling its share of renewable energy use by 2020. Another ambitious program aims at cutting energy use at China's top 1,000 enterprises.

ABB's contribution

The mitigation of climate change is a long-term issue that will call for significant changes in the way industry and society at large produce and use energy and electricity. Success will require changed consumer patterns as well as the development and deployment of new technologies on a large scale.

ABB has a two-year rolling target to reduce its use of energy per manufactured unit by 5 percent. During 2008, ABB increased its production output by 20 percent while its total use of energy remained relatively unchanged. This was due to energy efficiency programs initiated throughout the group. Typical measures include better climate control, more efficient lighting and the installation of energy efficient manufacturing equipment in factories and offices. This has resulted in impressive results from all over the world: for example, the electricity intensity at ABB China has fallen 55 percent over 5 years.

In 2008 ABB's installed base of low-voltage variable-speed drives saved an estimated 170 terawatt-hours of electric power, enough to meet the annual needs of 42 million households in the EU.

ABB will make energy audits and establish relevant energy-efficiency improvement programs for each of the 23 ABB manufacturing sites that consume more than 1 percent of the total group energy consumption.

In addition, ABB is committed to helping its customers use energy more efficiently and reduce their environmental impact with its broad array of products, systems and services. For example, the company's advanced information technology systems for the control and optimization of integrated industrial processes, electrical power grids and buildings save energy and reduce emissions.

The interconnection and strengthening of power systems with high-voltage direct current (HVDC and HVDC Light®) technology and flexible AC technologies (FACTS) make large savings through a more even distribution of loads, an efficient use of primary energy resources and increased power quality, thereby reducing CO_2 emissions. It also enables large-scale integration of renewable energy into the power grids.

ABB's high-efficiency motors and variable-speed drives for motors also contribute to large emission reductions. In 2008 ABB's installed base of low-voltage drives saved an estimated 170 terawatt-hours of electric power, enough to meet the annual needs of 42 million households in the EU and reduce global carbon dioxide emissions by some 140 million tons a year.

For ABB climate change is a huge opportunity and challenge: ABB must continue to live its slogan "Power and productivity for a better world" and continue to serve its customers with present and new technologies that meet increasing market demands on energy savings and climate efficiency in the long-term.

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Controlling the gas flow

ABB's SCADA and System 800xA improve LNG operations and management

Zhimei Feng, Fei Wang, Xiaoxing Bi

Many new liquefied natural gas (LNG) projects have been completed and are operating successfully in China, increasing LNG import trade volumes. International trade of LNG is generally based on long-term take or pay contracts where a buyer will pay even if the product is not required. This means that the import volume and storage capacity at the receiving terminal is directly influenced by downstream consumers. A transportation plan is specified in the contract, which determines the volume of LNG shipped from the upstream output terminal to the low-temperature storage tank of the receiving terminal. Through in-depth analysis of the supply and demand chain, a process control system is devised to ensure that the storage facility has the capacity to receive all scheduled shipments of LNG. This is achieved by controlling the gas transmission between the LNG receiving terminal and the trunk line. By utilizing information processing and automation control technology, errors of judgment can be avoided so that the arrival of LNG shipments at the eceiving terminal are coordinated efficiently and safely with gas transmission and combined dispatching of gas to downstream users.

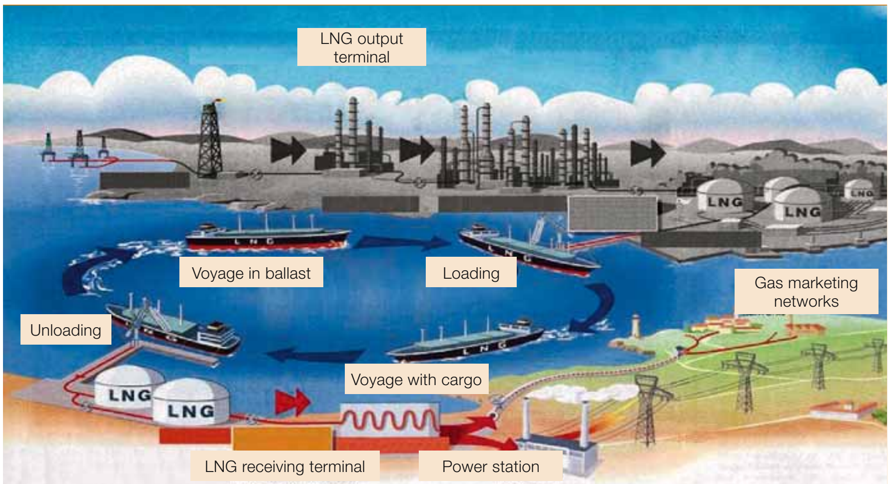
The Fujian LNG project in Southeast China is the first project under the independent management, construction, operation and maintenance of a domestic enterprise in China. Since February 2009, the gas for the project has been supplied by Indonesia from its Togguh Gas Field. Its current import capacity is 2.6 million metric tons of LNG per year with a further planned expansion of 5 million metric tons per year forecast for operations beyond 2012. The project includes an LNG receiving terminal and a 360 km gas transmission line, which passes through coastal regions and cities, namely Fuzhou, Putian, Quanzhou, Xiamen and Zhangzhou in the southeast of the Fujian Province, supplying gas to five city gas companies and three gas-fired power plants.

Generally, LNG is transported by special transport ships from the output terminal, at the place of origin, to the receiving terminal, where it is allowed to form a gas and is distributed through gas transmission lines to the end users. The principal ingredient of natural gas is methane (CH_4). When cooled to about –162°C, under ordinary pressure, it forms a liquid. The volume of natural gas can be reduced to about 1/600 when liquefied, making it more convenient for long distance transportation, storage and utilization. LNG has therefore become the major mode for natural gas transportation by sea.[1)]

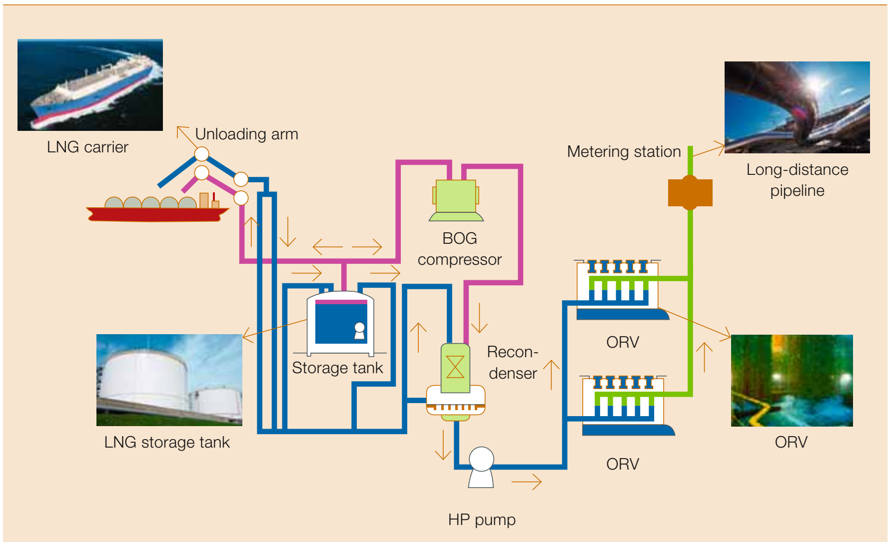
Today, a constant supply of gas to power stations and marketing networks is maintained through integrated production, transportation and distribution. For the Fujian LNG project a process has been established that includes LNG production, storage, transportation, receiving and regasification 1.

A constant supply of natural gas to power stations and marketing networks is maintained through integrated production, transportation and distribution.

1 LNG industry chain system



2 The processing system for an LNG receiving terminal



The LNG receiving terminal

Generally, LNG receiving terminals are composed of five process subsystems; namely LNG unloading, storage, regasification (export), vapor processing and flaring (venting) 2.

LNG unloading and storage

After the LNG transport ship has berthed at the jetty, the LNG output pipeline on the ship is connected to the onshore unloading pipeline via the unloading arm on the jetty. The LNG cargo is then pumped ashore from the tank on the ship to a storage tank at the receiving terminal. During this process the gas pressure in the storage tank on the ship would gradually drop, so to maintain pressure, gas in the onshore storage tank is sent back to the ship's storage tank by way of the gas return pipeline and gas arm. During periods when no LNG is unloading, the unloading pipeline onshore is kept cold using LNG from the onshore storage tank's transfer pump outlet. This LNG is returned to the storage tank by means of an insulated pipeline.

LNG regasification and export

After pressurization through the tank's transfer pump, part of the LNG in the storage tank enters the recondenser so that a given amount of vapor is liquefied. The mixed LNG from the recondenser and the tank's low-pressure pump is pressurized using a high-pressure pump and it enters the vaporizer. Meters measure the gas volume before it passes through the gas

Footnote

1) See "Tanking along" on page 74 of *ABB Review* 1/2009.

transmission line to the end users. To guarantee the normal operation of the tank's transfer pumps and high pressure export pumps, it is necessary to set regurgitant pipelines at all pump discharges. In this way it is feasible to regulate the flow using the regurgitant pipeline to compensate for changes in LNG transport capacity, so that low temperatures in the system can be guaranteed even when output has stopped.

LNG vapor processing and venting

The vapor processing system is designed to guarantee normal LNG storage tank operation within a certain pressure range. Within the storage tank a pressure transmitter monitors pressure values to ensure the tank is neither under nor over pressure. When the pressure is above or below the set value, the vapor processing system takes appropriate action to control the gaseous pressure inside the storage tank. To prevent a vacuum in the LNG storage tank, a vacuum-gas supply system is provided in the process flow.

ABB's SCADA system adopts an open, compatible and widely accepted standard communication protocol so that information can be exchanged with most types of distributed control system controllers.

The trunk line

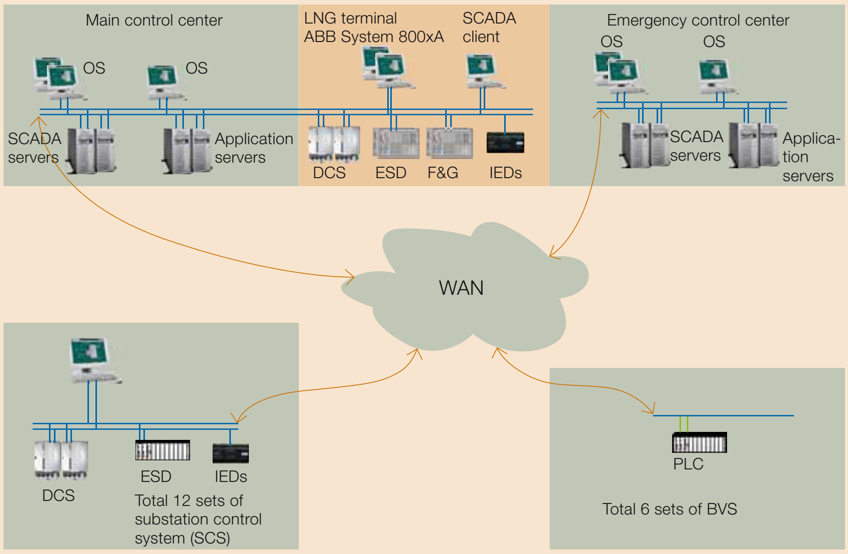
The trunk line comprises a gas pipeline with branch lines, a valve station and an offtake station. The valve station is designed to block the pipeline and provide unmanned monitoring and remote control, while the offtake station is designed to transfer natural gas downstream to end users, such as city gas stations and power plants, once it has been filtered, metered, heated and pressure regulated 3.

LNG control system

Since the Fujian LNG project involved processes, including a supervisory control and data acquisition (SCADA) system Factbox 1, an emergency shutdown (ESD) system Factbox 2, a fire and gas (F&G) monitoring system Factbox 3 and a distributed control system (DCS) Factbox 4, both local operation control and remote monitoring systems were required. Integrating these multiple systems was the most technically challenging aspect of the project.

To control the pump's direction of operation at the receiving terminal, the combined dispatch control logic was built into the DCS system at the receiving terminal. As part of the integrated design, priority was given to ensure smooth information exchange between the DCS and SCADA. At

3 The network structure drawing of Fujian LNG auto-control system



Factbox 1 Supervisory control and data acquisition (SCADA) Vantage system

The SCADA Vantage system improves the utilization efficiency of the pipeline service and the boosting station. As a result, turnover is accelerated and functions are enhanced. LNG can be transported from the place of production – in the shortest time and at minimum cost – to the place of installation. The solution provided by ABB keeps the operating cost as low as possible.

Characteristics:

- Redundant and open structure
- Object-oriented real-time database
- Integrated historic record server
- Integrated pipeline model and advanced flow chart
- Expandability from single-node equipment to multi-server system
- Intuitive configuration tools invoked in the total system and application
- Communication protocols supporting OPC and industrial standards, such as IEC 870 5 101/104 and DNP3.0
- Can be integrated simply with the automatic solution for pipeline station control

The SCADA Vantage system provides control and data acquisition for specialized industries, such as LNG storage and supply. It is versatile with open compatibility, allowing applications ranging from an installation in a single-node pattern to a multi-server system.

In addition, the processes are performed based on the principle of client/server and a redundant object-oriented system. Through a configurable authorization system, it provides a security guarantee to prevent unauthorized personnel from logging on to the system. The system communicates through the ODBC, COM, OPC and OLE standard protocols (for more details see "OPC Unified Architecture" on page 56 of this issue of *ABB Review*). In addition to these advanced characteristics, it possesses front-end communication with redundant configuration and can function using remote devices to complete automatic switchover should communications be interrupted.

present, most protocols designed for internal communication between the DCS system and the DCS controller are developed independently and are frequently incompatible. ABB's SCADA system however adopts an open, compatible and widely accepted standard communication protocol so that information can be exchanged with most types of DCS controllers. It is not easy to integrate a SCADA system with a DCS system, and it is even harder to integrate control systems when provided by different manufacturers. The Fujian LNG project adopted ABB's Extended Automation System 800xA to oversee control systems at the LNG receiving terminal and ABB's SCADA Vantage to oversee control systems on the gas-transmission line Factbox 5. This meant that the DCS, ESD system and F&G system at the receiving terminal station were fully integrated using the System 800xA platform. Its ability to use diverse communication protocols enables the System 800xA software to exchange data seamlessly with third-party equipment at the receiving terminal, while the SCADA Vantage software for the gas transmission line allows the simultaneous monitoring of both central and station control systems.

Factbox 2 Main design functions of the ESD system

1. Through the ESD button, manual emergency shutdown can be triggered to isolate the processing equipment of various units.
2. Emergency shutdown is triggered through the automatic detection instrument of the system; for input signals, use voting to guarantee the effectiveness of alarm or shutdown signal.
3. Reset of emergency shutdown. After the interlock triggering conditions have been manually confirmed and reset, the system can recover to a normal state to guarantee the safety of production.
4. Interlock bypass. The ESD system also provides maintenance bypass and an operation override button, which are used to conduct an online test on equipment without affecting normal production, to shutdown a bypass of the signal at the time of the initial start of the process system and to conduct a bypass operation on the ESD interface when the bypass permits the switch to be on the allowable position.

Factbox 3 Main design functions of the F&G system

1. Collect and display the working states of combustible gas and fire detector
2. Detect LNG leakage and give audible and visual alarm for the detected abnormal state
3. Collect and display the working states of fire-fighting equipment and auxiliary facilities
4. Execute the logic of emergency cut-off and display emergency cut-off alarm signal
5. Link fire-fighting equipment
6. Output emergency stop signal to ESD

The receiving terminal control system

In terms of control areas, the automation system of the receiving terminal can be divided into a central control system and a jetty control system. The central and jetty control systems contain a DCS, an ESD system and an F&G monitoring system. The assets under central control include all devices except those on the jetty, ie, the storage tank, compressor, recondenser and open rack vaporizer (ORV), which is heated by seawater.

The DCS is a major automation system used to monitor and control the process flow at the LNG receiving terminal. In addition the system also consists of the following two independent parts: the ESD system, which is designed to shut down the receiving terminal and the F&G monitoring system, which is designed to detect fire and LNG or NG leakage. The ESD system uses ABB's safety control system with safety integrity level 3 (SIL3). When process disturbances threaten personal security, the environment or equipment, or have the potential to cause major economic losses, the ESD system initiates the corresponding interlock protection to prevent further hazards or accidents escalating. The F&G system used was ABB's fire and gas control system with SIL3. This system detects fires and the leakage of LNG and hazardous gases, initiates an alarm, activates fire extinguishing systems as required and takes measures to isolate production equipment.

Gas transmission-line control system

ABB's SCADA Vantage, used to monitor and control the gas transmission line, consists mainly of primary and backup dispatch control centers, sev-

Factbox 4 Main design features of the DCS

1. Provide real-time monitoring of production processes, such as pressure, liquid level, temperature and flow
2. Dynamically display the production flow of the receiving station, major process parameters and the running state of equipment
3. Give alarm for abnormal operating conditions, print the alarm for the record and store important parameters
4. Allow online setting and modification of process control parameters and conduct remote operations on devices such as valves and pumps
5. Monitor the unloading, storage and gasification of LNG as well as the export and metering of natural gas
6. Maintain real-time communication with the following systems to complete the centralized management of the production information of the entire receiving station:

- LNG storage tank data acquisition system
- Boil-off gas (BOG) compressor
- Vibration monitoring system for in-tank pump and high-pressure pump
- Export pipeline SCADA control system
- Wharf berthing system
- Ship-to-shore communication system
- PMS system
- Natural gas analyzer
- Tanker loading control system
- Electrochlorine system
- Seawater system
- Trade metering system
- ESD system
- F&G system

eral station control systems for the off-take stations and a remote control valve station. Each off-take station and valve station with the control center, conducts data exchange through the main and backup communication lines, guaranteeing the reliability and security of data communication through the SCADA system. The SCADA system supports multiple communication protocols such as MODBUS TCP/IP, OPC and IEC104.[2)]

Integrated dispatching system

The SCADA system performs data acquisition and control for the offtake stations and remotely controls the valve stations of the gas transmission line. It also acquires the major process parameters of the receiving terminal in addition to data provided by the DCS, such as the level of LNG in the storage tank and the export quantity allocated for dispatch by trucks. This data is communicated by standard protocols, such as the OPC protocol or MODBUS TCP/IP. Regarding DCS as an off-take station of the SCADA system, it can realize real-time monitoring of the production operations of the receiving terminal, and through the Web server, enables users to monitor the production and operation conditions of the receiving terminal and gas transmission lines. Meanwhile, the SCADA system can collect the daily, weekly, monthly and annual gas delivery plan for downstream users and the transportation plan for the upstream LNG transport ships from Web servers. These data, together with data describing the export quantity of each offtake station, are transmitted to the DCS system. Through firewall protection, authorized users can log onto the Web server via the Internet to submit and modify the gas nomination plan. The combined dispatching function of the DCS will conduct a gas transmission and distribution forecast according to the liquid level in the storage tank, the LNG transportation plan and the gas delivery plan for downstream users. Then it will dispatch and control the export quantity

Footnote

2) The MODBUS Protocol is a messaging structure developed by Modicon in 1979, used to establish master-slave/client-server communication between intelligent devices. TCP/IP: Transmission Control Protocol/Internet Protocol. OPC: OLE for Process Control.

Factbox 5 Technical characteristics of ABB's control system: System 800xA

ABB's System 800xA provides a powerful control system with a simple, visually appealing human-system interface. It provides a flexible distributed engineering environment for engineering design, control strategy configuration, flow chart design, information management, resource optimization and the integration of field equipment.

Functional design of flow chart

The flow chart design of System 800xA enables the engineer to remain an engineer and not to become a computer programmer. The automatic construction of flow charts makes projects simple and practical. Since the design of flow charts is based on functions, a design can be completed without in-depth understanding of the controller and I/O. In addition, System 800xA also supports online monitoring and calibration functions.

Process visualization

Applying the elements and symbols predefined in the comprehensive library of System 800xA, the user can conveniently customize the interactive flow chart. The system also supports bitmaps, photographs and picture elements from third-parties.

Fieldbus management

Fieldbus management consists of HART (Highway Addressable Remote Transducer) communications protocols, Foundation Fieldbus and Profibus and provides the engineers with a convenient fieldbus design tool. This tool integrates network topology and field elements such as equipment parameters, a plan for application program, trial run and detailed diagnostic reporting.

Batch data management

Batch data management of System 800xA utilizes Microsoft Excel and Excel ADD-INS, allows the automatic import of external data such as signal list, label name or document. It can export system data at any time for verification and modification.

Report generation and distribution

System 800xA supports flexible and diversified report functions. The format of the report is familiar and easy to use. This not only fully meets the requirements for factory and documents, but can also act as a powerful tool for the user's decision making and planning, with improvable performances.

Perfect data conversion

The data structure and operation defined by users provide powerful algorithms and programs that can be used repeatedly. On this basis, the user can convert raw data into information, such as KPI (key performance indicators), raw material property and perfect control support. The data structure can also be used to integrate external data into the system.

Safe storage and history data access

Fault-tolerant distributed data structure guarantees reliable data storage and usability. The user has limited rights to access these data. Meanwhile, these data can be stored offline. Electronic data meets the demand of enterprise and provides a reliable basis for decision making.

Integrated management and configuration

The embedded history data processing function is designed as the configuration and management inside the system. This allows the management of single-point change and eliminates the risk of requiring additional project replication due to inconsistency of multiple databases.

Guarantees continuous batch production, stable product quality and production cycle

System 800xA batch management provides unrivaled management, batch control and program control, and observes industrial specification, security and reliability. In response to the ever-increasing product requirements, it provides fast and controllable responses and simultaneously reduces operating costs and production stoppages, thus winning a long-term competitive edge in the market.

from the receiving terminal according to the inlet pressure of the receiving terminal, the exports to the gas transmission line and the inventory of the gas transmission line 4.

In the control logic of combined dispatching, the DCS controller firstly assesses whether the export pressure is within the minimum and maximum working pressure range. If the working pressure is too high (about 90 percent of maximum working pressure), the system conducts the export decrease operation: If this pressure exceeds the maximum working pressure, the ESD system will conduct an export emergency shutdown operation. If, however, the working pressure is too low (about 110 percent of the minimum working pressure), the system conducts the export increase operation: If this pressure is lower than the minimum working pressure, the ESD system will conduct an export increase operation and signal an alarm.

The DCS controller will immediately calculate the difference between the output of the receiving terminal and the total output of the various offtake stations. It will estimate the inventory in the gas transmission line and determine whether the present export quantity plus the inventory can meet the demand over the next two hours, taking account of the previous two-hour gas delivery plan. Should the predicted demand exceed the expected export quantity, the DCS controller will conduct an export increase operation.

When the system is determining whether to conduct an export increase or an export decrease operation, it first checks whether there have been any major fluctuations in the gas consumption in the last two hours according to the gas delivery plan. If the fluctuations are within the maximum export quantity for a set of high-pressure pumps, it is merely necessary to start or stop these pumps. If the variation is higher than the maximum export quantity for this single set of high-pressure pumps, it will be necessary to start or stop two sets of high-pressure pumps or possibly three sets, depending on the size of the fluctuation. When conducting an export increase or an export decrease operation, it is also necessary to adjust the operations of other process equipment accordingly, such as low-pressure pumps and seawater pumps, to coincide with the revised export quantity. When the motor control center (MCC), which includes the controls for low pressure, high pressure and seawater pumps, fails to meet the requirement of the control logic, the DCS controller will automatically send an alarm to prompt the operator to switch to manual processing.

ABB's SCADA and System 800xA improve the working efficiency of production dispatching, avoid errors of judgment in operation, and coordinate the combined dispatch control between the LNG receiving terminal and the gas-transmission line.

With reference to the transportation plan of the LNG transport ships, the integrated dispatching system judges whether the LNG allowance can meet the planned export quantity of the gas transmission line during the forecast period until the LNG transport ship unloads. If the LNG allowance fails to meet the requirement, the system sends an alarm to remind the operator, through negotiation with the downstream users, to adjust the gas consumption plan. In addition, the system also judges whether there is adequate space in the storage tank to accommodate the discharge of LNG from the ship. Should the capacity of the storage tank be insufficient, the system sends an alarm to remind the operator that he should consult with downstream users to adjust the gas delivery plan or increase delivery of the gas through other modes (such as tanker transportation), so that adequate space can be created in the storage tank to accommodate the arrival of the scheduled LNG shipment.

The control system

The structure of the control system is shown in Factbox 5. The main control center communicates with the control system at the receiving station and the control center of the offtake station. The offtake station control center oversees several offtake stations and valve houses. The design ensures that the servers, controllers and networks are redundant so that the system's safety is guaranteed.

Optimization

Since the start of its operation, the Fujian LNG project has successfully received its first shipment of LNG. The optimized control solution can save millions of dollars on the monthly supply of LNG. Natural gas has been transported to such stations as Putian, Hui'an, Quanzhou and Honglu, and the downstream users are already using the natural gas provided by the Fujian LNG project.

By taking full advantage of automatic control and information processing technology to integrate different but associated production process control systems, the Fujian LNG project can efficiently implement the combined dispatch of LNG to end users. ABB's SCADA and System 800xA improve the working efficiency of production dispatching, avoid errors of judgment in operation, coordinate the combined dispatch control between the LNG receiving terminal and the gas transmission line, and thus improve the comprehensive capability of the enterprise in production, operation and management.

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Further reading

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ABB System 800xA Technical Manual
ABB SCADA Version Technical Manual

Restoring confidence

Control-center- and field-based feeder restoration

James Stoupis, Zhenyuan Wang, Fang Yang, Vaibhav Donde, Fahrudin Mekic, William Peterson

Severe – and not so severe – weather conditions have the potential to wreak havoc with electric utility transmission and distribution systems. The speed and efficiency at which these repairs can be carried out depends largely on the type of decision support systems or tools available to the distribution utility.

The traditional procedure for restoring power, ie, a trouble call system and crew dispatches, may take several hours to complete. In recent years, utilities have deployed automated feeder switching devices with communications, such as reclosers and circuit breakers with intelligent electronic devices (IEDs) for protection and control applications, and as a result, the power outage duration and system reliability have been significantly improved. The information provided by IEDs has made automated fault location identification and fault isolation relatively easy to achieve. Automated power restoration, however, is another story altogether.

ABB has developed two complementary power restoration control schemes that are in essence self-sensing and self-healing distribution network solutions.

Traditionally, electric utilities use the trouble call system to detect power outages, ie, customers report when they experience a power outage. The distribution system control center then dispatches a maintenance crew to the field where they investigate the fault location before implementing various switching schemes to conduct fault isolation and power restoration. This procedure may take several hours to complete, depending on how quickly customers report the power outage and the maintenance crew locates the fault point.

Over the years demands on utilities have continued to increase, causing many distribution networks to become less (traditionally) passive and more active or dynamically adapting.

Identifying and isolating a fault is now considered relatively easy. Automatically restoring power, however, remains a challenging task.

Grids that can think for themselves

Smart grid, for some electric utilities, refers to electric power systems that enhance grid reliability and efficiency by automatically anticipating and responding to system disturbances. To achieve smart grid at the power distribution system level, various automation technologies have been attempted in the areas of system metering, protection, and control. Within these technologies, automated power restoration is an important part of the smart grid puzzle.

In moving closer to the smart grid concept, utilities have, in recent years, deployed feeder switching devices, such as reclosers and circuit breakers with intelligent electronic devices (IEDs) for protection and control applications. The automated capabilities of IEDs, such as measurement, monitoring, control and communications functions, make it practical to implement automated fault identification, fault isolation, and power restoration.

The IED data is transmitted back to a substation computer or a control center, and based on the information automated fault location identification and fault isolation are relatively easy to achieve. As a result, power outage duration and system reliability have improved significantly.

While identifying and isolating the fault may now be relatively easy, automatically restoring power remains a challenging task. Many research efforts have been dedicated to tackling this task, including consideration of the operating constraints, load balancing, and any other practical concerns.

As a result of its own research effort, ABB has developed two complementary power restoration control schemes: field-based and control-center-based. Both schemes conduct a restoration switching analysis (RSA) to achieve back-feed power restoration, ie, healthy load zones that have lost power will be restored through their boundary tie switching devices from neighboring sources. However, the field-based scheme uses a substation computer, the COM600, to run the RSA while the control-center-based scheme uses the Network Manager-DMS outage management system.

ABB has developed two complementary power restoration control schemes, field-based and control-center-based, which conduct a restoration switching analysis to achieve back-feed power restoration.

The field-based scheme

In the field-based scheme, the substation computer, the COM600, hosts the RSA engine and is used to communicate with feeder IEDs. It also acts as a soft programmable logic controller (SoftPLC) which issues control commands to the IEDs based on the restoration switching sequence produced from the RSA engine.

The RSA engine in the COM600 has a simple distribution network model that includes major feeder components: sources such as distribution substation transformers; switching devices, ie, "switches" that act to sectionalize parts of the network, load switches, circuit breakers and reclosers; and loads. It uses a network-tracing-based algorithm to reach a valid post-restoration network that satisfies the following requirements:
- The network is radial.
- There is no current violation on any network component.
- There is no voltage violation at any network node.

Therefore, the restoration switching sequence is generated online according to the pre-fault network condition instead of pre-programmed rules that are usually generated offline.

In a field-based scheme, the restoration switching sequence is generated online according to the pre-fault network condition instead of pre-programmed rules that are usually generated offline.

The capacity of a potential back-feeding source may be limited, and in some cases multiple back-feeding sources may be required to reach a feasible restoration solution. In the context of this article, if a source can provide the restoration power over a single path to an out-of-service load zone, the restoration is called "single-path restoration." Otherwise, the out-of-service load zone may have to be split into two or more load zones to be back-fed, and the scenario is then called "multi-path restoration." Both single-path and multi-path restorations may have to shed load in case the back-feed source capacity or feeder components' loading capability is not sufficient.

The RSA engine's algorithm starts with a back-feeding isolation switch search, which is carried out on the pre-fault network's tree structure with the tripped breaker/recloser as the root. The search is conducted down the tree to find the most downstream switch that passed the fault current. This switch is then named the "forward-feed isolation" switch. The search then moves further down to the first layer of downstream switches, which are named the "back-feed isolation" switches. The algorithm then applies numerous recursive steps, including:

- Identifying any multi-connected load nodes (also known as "T-nodes") via tracing.
- Determining if single-path restoration can be achieved via a single source. If single-path restoration cannot be achieved, the algorithm then continues to search for other switches in the network in order to achieve multi-path restoration.

In the case of multi-path restoration, the algorithm tries to determine the best reconfiguration. In some cases, the network must be divided into two sub-networks to restore all the possible unaffected loads, moving one or more normally open tie switches to other switching device locations. In other cases, all the unaffected loads cannot be completely restored, even if the tie switch locations are moved.

Typical RSA engine outcomes are illustrated in 1 and 2. In 1a, single-path full restoration is used where a fault at T-node, L3, must be isolated by opening the forward-feed isolation switch (R3) and two back-feed isolation switches (R6 and R10).[1] Back-feed sources (S3 and S4) both have sufficient capacity to pick up the out-of-service load on their corresponding restoration path, and each tie switch (R9 and R12) can be closed to achieve the restoration. The post-restoration circuit topology in 1b. 2a shows a multi-path full restoration example, where a fault at load node, L1, must be isolated by a forward-feed isolation switch (R1) and a back-feed isolation switch (R2).[2] In this example, none of the back-feed sources (S2 to S5) can completely pick up all the unaffected loads after fault isolation. Hence the algorithm splits the network into two parts by opening R13, and the out-of-service load is restored by closing both R8 and R11 (from both S3 and S4). The post-restoration circuit topology is shown in 2b.

Operation of the field-based scheme was validated using an example of a demo distribution system that has three sources, five switches and three loads 3. By implementing the algorithm in a COM600 to control five IEDs, the demo shows how single- and multi-path restoration scenarios are achieved. For example, since neither of the given source capacities at sources S2 and S3 is enough to restore the sum of the loads L2 and L3, a fault

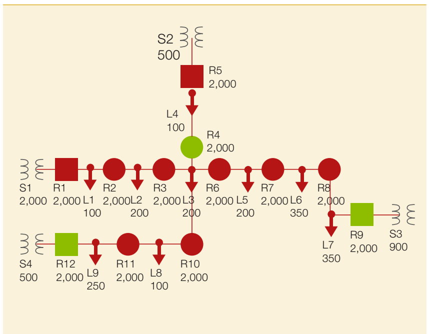
Footnotes

[1] Normally a feeder circuit breaker will not act as a tie switch. In this example, they are used as tie switches only to illustrate the concept.

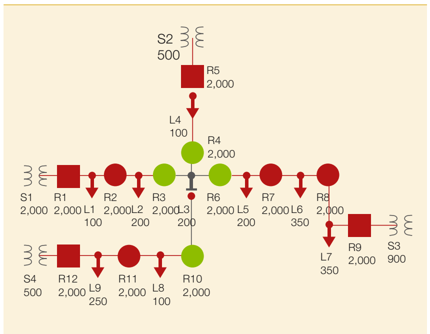
[2] In this case no forward restoration is required.

1 A single-path restoration example

a Normal topology

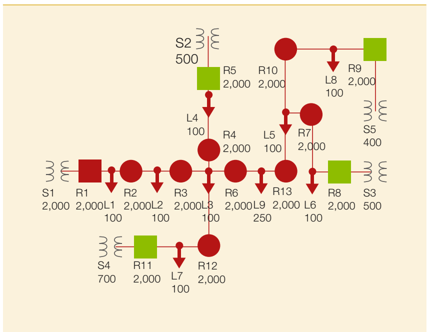


b Post-restoration topology

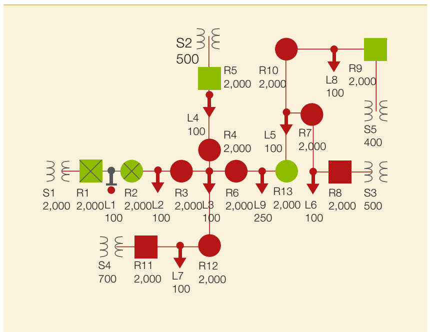


2 A multi-path full restoration example

a Normal topology

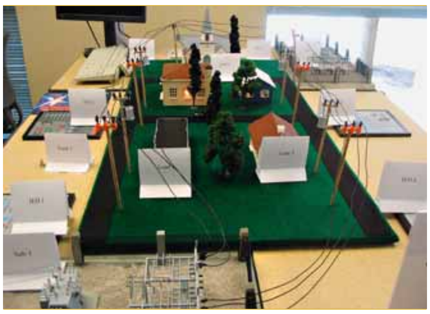


b Post-restoration topology

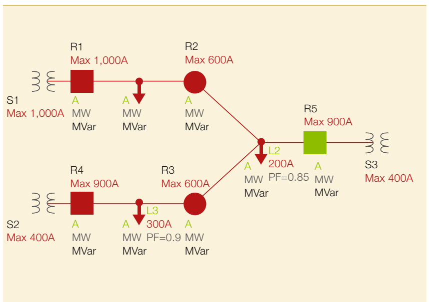


3 The demo circuit

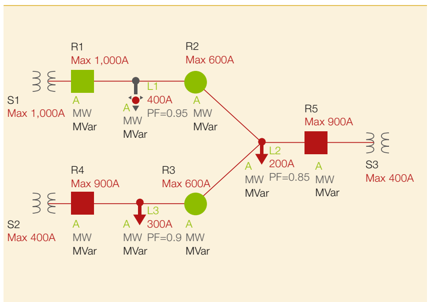
a Physical circuit



b Normal operation

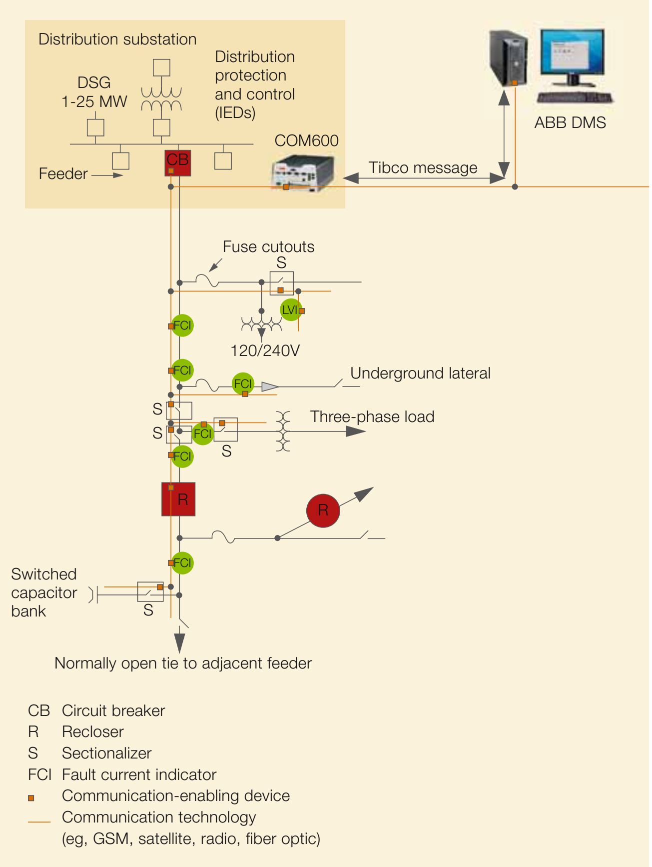


c Post-restoration operation



at load L1 causes R3 to open, which in turn splits the out-of-service network composed of L2, R3 and L3 3b. Both tie switches R4 and R5 close to restore power to the out-of-service loads 3c.

4 High-level architecture for integrated feeder automation and DMS



Network Manager-DMS is ABB's outage management and trouble call system that contains the network model for an entire utility distribution system.

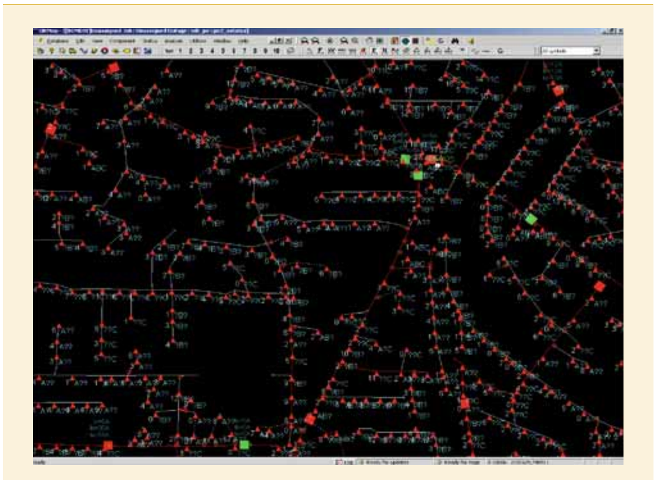
The control-center-based scheme

In a control-center-based scheme, the substation computer COM600 is used as a gateway to transmit field IED data back to the outage management system at the control center, and conversely control commands from the control center to the field IEDs. The COM600 first uses industry-accepted protocols, such as IEC 61850, DNP3 and Modbus, to obtain the necessary data from each of the feeder IEDs, and then analyzes this data to detect if a fault has occurred in the system. In the event of a fault, the COM600 sends this information upstream to the Network Manager-DMS via proprietary methods using a real-time messaging system. When the Network Manager-DMS receives the data, it analyzes it, determines the location of the fault, and subsequently runs the RSA to determine the proper isolation and restoration switching actions that should be taken. The Network Manager-DMS then sends the switching control commands to the COM600 either automatically or after an operator authorization action, whichever is preset in the control center DMS application. The high-level system architecture of this scheme is shown in 4.

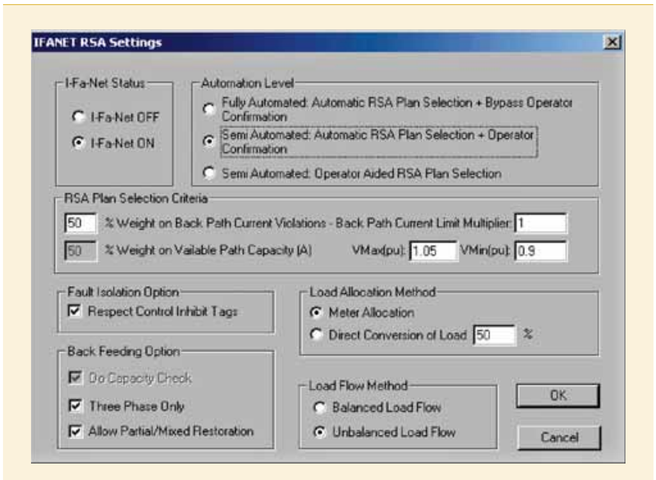
Network Manager-DMS is ABB's outage management and trouble call system. It contains the network model – which is typically stored in an Oracle database - for an entire utility distribution system, from substation components all the way down to residential service transformers. The control-center operator interface for a typical residential distribution system, modeled in Network Manager-DMS, is illustrated in 5. The solid lines represent overhead distribution lines and the dotted lines represent underground distribution lines. The boxes represent reclosers or switches, with the red boxes indicating normally closed devices and the green boxes indicating normally open devices (ie, potential restoration paths). The red triangles represent service transformers.

Historically, when customers lose power, they call the utility's automated answering system, which enters the outage data into Network Manag-

5 Operator interface (OrMap) for Network Manager-DMS



6 Operator-setting interface for control-center-based restoration

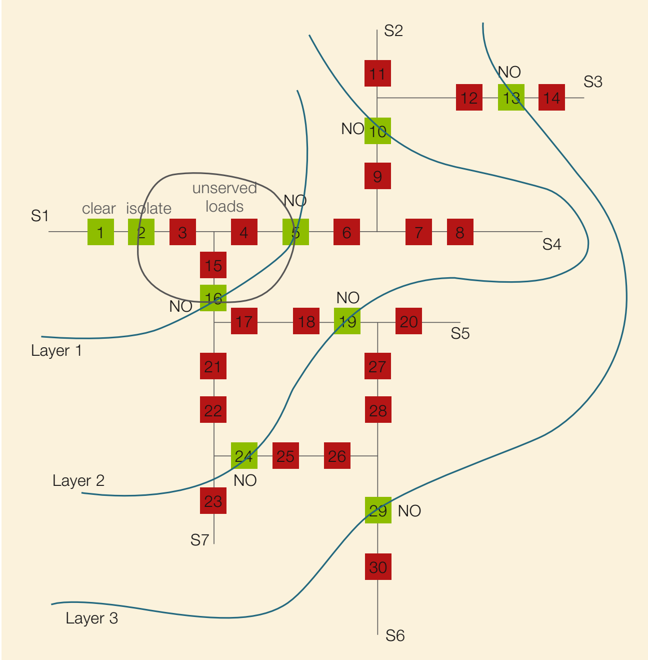


er-DMS. This data is then displayed on the operator interface. As more phone calls come in, Network Manager-DMS tries to determine the cause of the outage, for example if a switching device or fuse in the field operated to clear a fault or if a transformer or other component failed. The operator then uses the interface and output of the RSA feature of Network Manger-DMS to coordinate isolation and restoration of the feeder by dispatching crews to conduct switching operations.

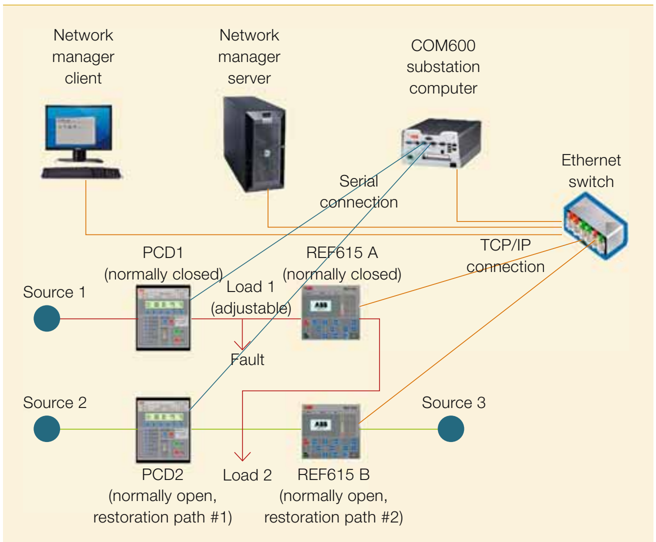
With the integrated control-center-based restoration scheme, the COM600 will detect the outage based on the IED-sensed network events, and inform the Network Manager-DMS automatically. When the Network Manager-DMS receives this notice, it will run the RSA with respect to the outage area and generate power restoration schemes, which are otherwise known as restoration switching plans (RSP). Whether an RSP is sent to the COM600 for execution immediately after the RSA run is based on the operator's preferences. The operator interface application allows three types of restoration control 6:

- Fully automated control where the operator is not involved in the RSP execution process
- The operator one-click confirmation-based RSP execution
- The operator-aided RSP selection and execution

7 The multi-layer restoration switching analysis (RSA) concept



8 Connection diagram for the control-center-based restoration demonstrator



The RSA is based on the detailed network model and unbalanced load-flow analysis of this model to make sure the post-restoration network does not have current and voltage violations. The RSA combines a network-topology tree-tracing and genetic algorithm, thereby enabling it to take care of both lightly and heavily loaded network conditions. If the loading of the network is light, then single-path restoration is sufficient. If the network is heavily loaded, either a multi-path restoration is required, or a multi-layer RSA has to be used.

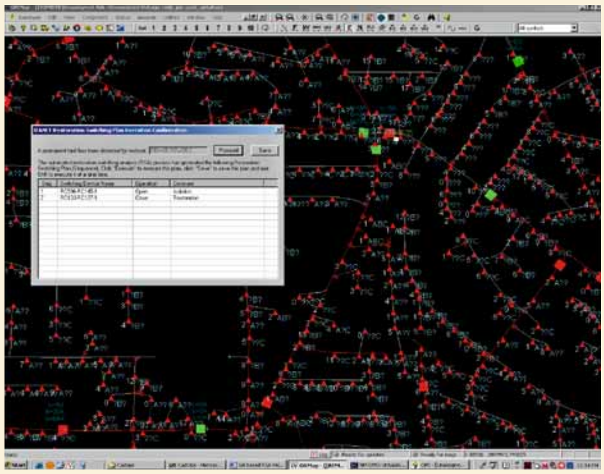
The concept of the multi-layer RSA is explained in 7, where the green squares represent tie switches or fault clearance/isolation switches. The tie switches that bound the unserved load area are called the first layer of tie switches for restoration. Subsequent layers are named sequentially (eg, second layer, third layer). Under heavy load conditions, only closing the first layer restoration switches may not be suitable to meet the power requirement of the unserved loads. Thus, load transfers from the zone between the first and second layers to the zone between the second and the third layers may be necessary. ABB has implemented a genetic algorithm-based method to resolve this problem.

A control-center-based scheme has been developed and validated by ABB in the lab and a demonstrator built to show the concept 8. A Network Manager-DMS server was configured to store an example network model, and a Network Manager-DMS client laptop was configured to be able to access and display this model. These computers, together with the COM600 substation computer and two REF615 distribution IEDs, communicated with each other via TCP/IP through an Ethernet switch. The two PCD recloser controllers communicated with the Modbus protocol through serial connections to the COM600.

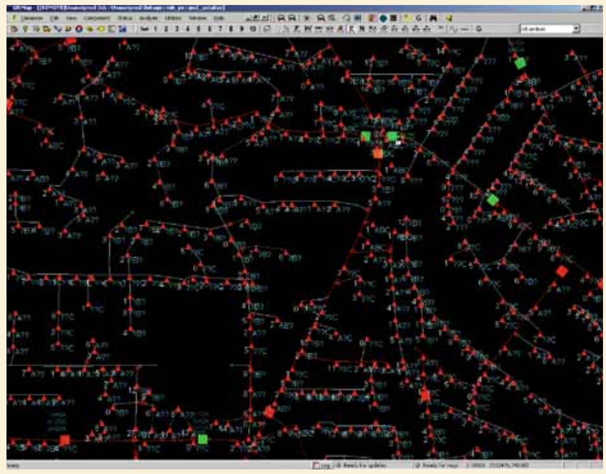
In 8, Load 1, the adjustable load, is a light bulb controlled by a dimmer switch, which is set via a remote control. Load 2 is fixed, ie, a light bulb with no dimmer switch. A fault is simulated at Load 1 by pressing a button on the dimmer switch remote control, thereby increasing the load (light-bulb illumination) level from the half-load to the full-load setting of the switch. This action causes a fault, forcing PCD1 to go through a reclosing sequence to lockout: its over-current pickup setting lies between the pre-fault load level (half load setting) and the fault load level (full load setting).

When PCD1 locks out, this action triggers the fault detection in the

9 NM-DMS operator interface (OrMap) screen for semi-automated RSA



10 NM-DMS operator interface (OrMap) screen after restoration



COM600. When the fault has been detected, the Network Manager-DMS is notified and the RSA is automatically run to determine all the restoration paths. The RSA setting will determine if the isolation and restoration actions are fully automated, semi-automated with one-click operator confirmation, or semi-automated with operator confirmation where the operator selects the restoration path. In the first two cases, the best restoration is automatically determined by the RSA. In the last case, the operator "manually" selects the best path by analyzing the output data of the RSA, such as allowable capacity, loading levels, and load-flow violation data. The Network Manager-DMS operator interfaces for semi-automated isolation and restoration with one-click operator confirmation are shown in 9 and 10.

This demonstrator was shown at several conferences in 2009, including DistribuTech, ABB Automation & Power World 11, and the FERC Expo Day.

ABB is actively developing new grid technologies, especially in the distribution automation, feeder automation and distribution control application areas.

Self-healing distribution networks

ABB is actively developing new grid technologies, especially in the distribution automation, feeder automation and distribution control application areas. The field-based and control-center-based power restoration control schemes are just two examples of these developments. These technologies provide a self-sensing and self-healing distribution network solution, greatly reducing the customer outage time and increasing service reliability.

11 The demonstrator at the 2009 ABB Automation & Power World in Orlando

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Reference

[1] **Wang, Z., et al.** (July 2009). A deterministic analysis method for back-feed power restoration of distribution networks. IEEE General Meeting, Calgary, Alberta.

The power to make a difference

HVDC Light® can deliver 1,100 MW

Björn Jacobson, Marc Jeroense

Our appetite for electric power seems to have no limits and is predicted to double over the next 40 years. This heavy demand for electricity comes at a cost to the environment, both in its generation and in its transmission. An increasing share of new power generation comes from renewable sources, often located in remote areas. Since the mid 1990s, ABB has been developing a new system, called HVDC (high-voltage direct current) Light®, for electric power transmission, with the aim of providing a new transmission alternative, reducing some of the inherent disadvantages of the existing systems. With HVDC Light systems it is possible to transfer DC power over long distances on land by the use of robust and quick-to-install polymeric cable systems. Similarly, submarine cables can be used for sea crossings. HVDC Light converters enrich the electric transmission network with properties like improved black-start capabilities.

Transmission and distribution

In our urbanized world, there are fewer places to erect new power lines. Furthermore, the rise of sustainable energy sources, like solar, wind and remote hydroelectric generators, put greater stress on the power grid. In the remote regions where this power is usually generated, the grid is often weak. Today, renewable energy sources are more commonly used, since they are seen as a solution to the rising CO_2 problem. New climate-protection and energy-trading initiatives have inevitably led to new demands on transmission systems. HVDC Light® technology provides a new alternative for bulding the vital reinforcements required in the grid.

Transmitting bulk power

HVDC allows long-distance electric power transmission with low losses. Classically, HVDC has been used for sea cables or high-power, long-distance transmission. ABB has been at the forefront of this development since the 1930s and has a long record of successful HVDC projects, from the first commercial 12-pulse converters in Gotland in 1954, to today's large-scale systems under construction in China that are capable of transmitting up to 6,400 MW of power 2,000 km from large hydroelectric power plants in western China to southern and eastern China 1.

Power conversion

Electric power is generated as AC in a power station and delivered as AC to the consumer. HVDC transmission needs converters at either end to convert AC to DC (using rectifiers), and DC to AC (using inverters). The conversion is carried out using thyristors in the classic HVDC system and transistors in HVDC Light system.

HVDC Light

ABB is the only supplier with operational experience of more than 10 years for such a voltage-source converter (VSC) transmission system. The first HVDC Light project was the 10 kV trial transmission system in Hällsjön-Grängesberg completed in 1997. Since then, many converter stations have been built and continue to operate successfully in the hands of satisfied customers.

VSC transmission can be connected to very weak networks, and even to networks without additional power sources. It stabilizes voltage by injecting or absorbing reactive power as required, allowing power flow and voltage at the connection point to be controlled simultaneously and independently. In classical HVDC (using thyristor-based converters rather than transistors), such independent control of active power and network voltage is not intrinsic, requiring extra equipment. Furthermore, with VSC transmission, the flow of power can be reversed without changing the polarity of the voltage, a facility not possible with classic HVDC. Instead, the power reversal is achieved by reversing the current direction. Such a property is of great benefit, since polarity reversal might cause high electric-field stresses in the cable system.

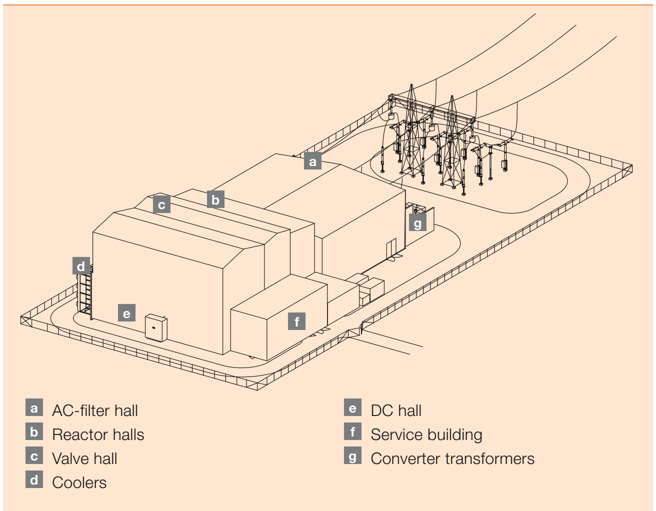
ABB is the only supplier with operational experience of more than 10 years for such a voltage-source converter (VSC) transmission system.

HVDC Light cables are configured as a basic bipolar pair – one cable with positive polarity, the other with negative polarity. By operating the cables with anti-parallel currents, the overall magnetic field of the cables is nearly eliminated, which is another positive aspect of HVDC Light technology. Through the coordinated development of converters, insulated-gate bipolar transistors (IGBTs) and HVDC Light cable systems, VSC transmission can produce a synchronized voltage for an entire wind turbine park and can now provide an alternative to high-voltage (400 kV and 500 kV AC) power lines. The design philosophy used to improve HVDC Light voltage levels has been one of cautious extension to existing voltage levels 2. Stringent tests have been carried out according to

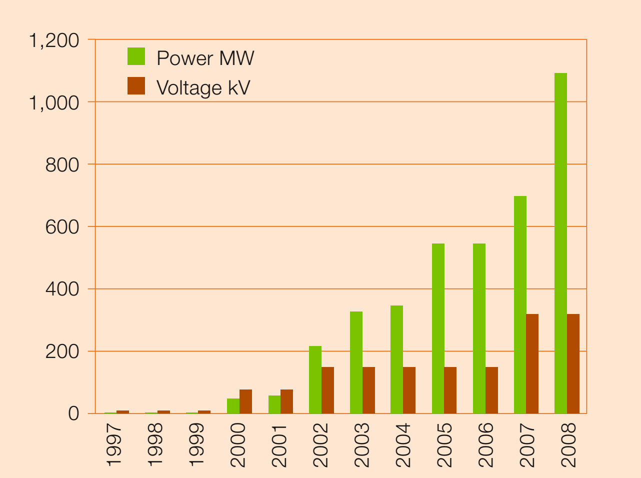
Footnote

1) Cigré is a non-governmental organization established in 1921 to provide guidelines related to the planning and operation of power systems.

1 1,100 MW converter station: The station layout in this example covers 160 m x 70 m to the fence.



2 Historical development of higher HVDC voltage levels



Cigré recommendations.[1] Prototype tests, high-voltage insulation tests and component tests have been performed at ABB and at third-party laboratories. Critical components have been tested in a specially built, unique high-voltage switching circuit. Calculations, simulations and operational tests at full power per component have then been verified by measurements in the field. In fact, with more than 1,500 km of HVDC Light cables installed and more than 28,000 IGBTs operating in 29 converters (or 22 converter stations), ABB has earned a reputation for effective and reliable power transmission through HVDC Light technology Factbox.

Specialized transistors

ABB produces all IGBTs for HVDC Light, the largest of which has a maximum turnoff current of 4,000 A in normal operation and can withstand about 18 kA during short-circuit conditions 3. These data translate to a DC capability of around 1,800 A, when safety margins have been added.

Control system

The MACH2™ control system is computerized and fast. The cycle time for the internal control loops is 100 µs. The system keeps track of the state of the converters and the attached equipment and protects it from current or voltage overloading. The control includes fast internal valve current and DC voltage regulation. The fastest protection circuits act within 10 µs to protect the valves.

The main functions of MACH2 include power and voltage control. Frequency control and reactive-power control can be used alternatively to control the system. The active power can be controlled by setting it to a certain level, or by letting the network frequency determine the power need (so-called automated mode). Likewise, the reactive power can be set or allowed to vary as a function of the network voltage (so-called voltage control mode).

Different types of damping functions are available on request, for instance damping of sub-synchronous torsional interaction between the grid and generators. HVDC Light can help to dampen these oscillations, thereby protecting generators from potentially harmful vibrations.

The MACH2™ control system keeps track of the converters and attached equipment, protecting them from current or voltage overloads.

New possibilities with HVDC Light

With the introduction of HVDC Light stations and extruded polymeric cables, the traditional market for HVDC cable interconnections, ie, long submarine links, is expanding and new market-driven opportunities are developing. These include offshore applications, such as mainland-grid power supply to oil platforms and the transmission of offshore-generated power from wind farms. Since HVDC Light cables have no alternating magnetic and external electric fields and the cables can be buried underground, acceptance of new power transmission systems using HVDC Light technology is high. Reduced visibility together with fast, relatively unobtrusive installation, all contribute to shortened approval processes, and a short project realization time. The small dimensions of the cable system and the simplified installation procedure with a reduced number of joints per kilometer, together with the durability of the underground cabling, make installation and maintenance highly cost effective. In an HVDC Light transmission system, a significant part of the cost is in the conversion equipment. Further, the transmission capacity, unlike an AC line, is not reduced with increasing distance. This makes the HVDC Light system more cost effective with increasing transmission distance. Local conditions vary a great deal but in the cases studied it has been shown that for distances above 200 km HVDC Light can be an attractive alternative to overhead lines of comparable capacity, even from a financial point of view.

Extruded versus mass-impregnated cable

Cables insulated with mass-impregnated (MI) paper can also be used with HVDC Light, as was the case in the Valhall project. Both polymer and MI cables can and have been used in the sea, but MI cables are at the moment preferred for the highest voltages (400 to 500 kV DC). Polymer cables are preferred on land because they are fast and easy to join and install 4.

Factbox Abundant experience in HVDC Light and static var (Volt-Amps-reactive) compensation (SVC) installations.

Project	Number of converters	Year in operation
1 Hällsjön	2	1997
2 Hagfors (SVC)	1	1999
3 Gotland	2	1999
4 Directlink	6	2000
5 Tjæreborg	2	2002
6 Eagle Pass	2	2000
7 Moselstahlwerke (SVC)	1	2000
8 Cross Sound Cable	2	2002
9 Murraylink	2	2002
10 Polarit (SVC)	1	2002
11 Evron (SVC)	1	2003
12 Troll A	4	2005
13 Holly (SVC)	1	2004
14 Estlink	2	2006
15 Ameristeel (SVC)	1	2006
16 ZPSS (SVC)	1	2006
17 Mesnay (SVC)	1	2008
18 BorWin 1 (Nord E.ON 1)	2	2009
19 Martham (SVC)	1	2009
20 Liepajas (SVC)	1	2009
21 Siam Yamato (SVC)	1	2009
22 Caprivi Link	2	2010
23 Valhall	2	2010
24 Liepajas Metalurgs (SVC)	1	2010
25 Danieli – GHC2 (SVC)	1	2011
26 Danieli – UNI Steel (SVC)	1	2011
27 EWIP	2	2012

Projects 1–18 have been installed; 19–23 have been ordered and are in production, but not yet commissioned.

3 IGBT valves – the heart of the converter

Cables and overhead lines

Cables are not always a real alternative, for example in mountainous terrain, where it is difficult for diggers and trucks to gain access. In certain environments overhead lines result in substantially lower costs. In these situations, HVDC Light can be used with overhead lines. One example is the Caprivi Link in Nambia, which is under construction with overhead lines that cover 970 km of rugged terrain, expected to be operational in late 2009. When using HVDC overhead lines, the power per line can be higher than the corresponding AC line, particularly for long lines; this means fewer transmission lines are necessary to carry the required power and, therefore, fewer right-of-way issues

4 The cables for HVDC Light are extruded polymeric cables.

a Aluminum conductor
b Resistive polymer
c Insulating polymer
d Outer resistive polymer
e Sheath
f Moisture barrier
g Mechanical protection

need to be resolved. It is even possible to combine overhead lines with cables. Here, since the line is open to the atmosphere, the cable has to be protected from lightning overvoltage with surge arresters and electronic protection.

> ABB's HVDC Light, with its powerful IGBTs and high-tech cables, can now deliver 1,100 MW of power.

AC is not suitable for long high-power cable transmission

AC oscillates with 50 or 60 cycles per second (50/60 Hz power frequency) regardless of whether it is extra-high voltage, high voltage, medium voltage or low voltage. For each cycle, the AC cable is charged and discharged to the system voltage. This charging current increases with cable length. At a certain length, the charging current of the cable become so large that nothing remains for useful power. Of course, long before this happens, the AC cable is no longer economical. The problem gets larger with higher applied voltage. This limits length and power ratings for AC cables. For short distances, they may be very useful, but not for long high-power transmission. DC cable, on the other hand, has no corresponding charging current. In the DC cable all current is useable.

HVDC Light transmission comes of age

With ABB's powerful IGBTs and sleek high-tech cable systems, HVDC Light technology is now in a position where it can be used as an integral and important part in transmission systems of the world. The term "Light" now applies only to the ease of application, not to any lack of muscle. With a wealth of experience from many field installations, its reliability is proven and assured.

ABB engineers keep extending the boundaries of the technology. Voltage, current, power, footprint and efficiency are some of the key parameters that are being continuously improved. In the long run, one also may envisage a DC grid overlain on the AC grid to increase capacity without losing stability and without requiring more overhead lines. There are still a number of issues to be solved for a DC grid, in particular breaking DC currents; however, a DC grid could be the best solution to bring in and distribute sustainable energy from sun, wind and water, thereby reducing CO_2 emissions. In general, key items under continuous development include IGBTs, cable systems and control system hardware and software.

Changing power

HVDC Light has reached an important milestone and is now available at a power level of 1,100 MW. This creates a new transmission alternative with underground DC cables, transmitting power over large distances. New possibilities are also offered – for instance, grid reinforcement in the existing networks, feeding isolated loads like offshore installations and bringing electric power from remote sustainable sources to where people live and work.

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The balance of power

Advanced transmission grids are embedding HVDC Light®

Jiuping Pan, Reynaldo Nuqui, Bertil Berggren, Stefan Thorburn, Björn Jacobson

Have you ever wondered how tightrope walkers manage to maintain their balance on such a narrow cable? These artists must not only maintain their own equilibrium, but must also take into account that their motions cause the line on which they are standing to move. One way to deal with this challenge is to move very slowly so that oscillations never surpass a critical level. A more advanced approach would involve the acrobat actually taking these movements into account and using or counteracting them, so keeping them under control while permitting more and faster activity. The more flexibile reactions of the acrobat permit a fuller use of the system's overall dynamics.

On first sight, this may not appear to have much in common with operating a grid. Grids, however, can also have significant stability problems. The traditional remedy, has been to keep loadings below set levels to avoid any risk of instability. Liberalization of electricity markets and the growth of renewable sources are leading to more long-distance transmission and are requiring enhanced network controllability. With HVDC Light®, ABB has introduced a technology that can not only improve transmission capability, but can also actively damp oscillations and enhance stability.

Transmission and distribution

Traditionally, most grids were structured to deliver power from generation plants to customers in the vicinity. Power plants are thus often located around major cities, with the grid infrastructure closely reflecting this match. Today, more and more power is being generated further afield and transmitted over longer distances. This change is driven by multiple demands: One of these is the growing usage of renewable energy, which is often generated in remote locations. Another is the increasing liberalization of power markets, favoring use of generation facilities with the lowest incremental costs. High-voltage grids are thus more and more handling long-distance transmission, and operators are seeking ways to reduce obstacles to the remote sourcing power.

With high-voltage grids increasingly being used in a way for which they were not initially designed, some corridors are having to carry more power and are being operated closer to their limits than ever before. In the case of energy from renewable sources, the challenge is compounded by the intermittent and to some extent unpredictable nature of the supply. New technologies are thus being sought to support these demands while maintaining controllability and stability.

This means that the grid's "natural" power flow, as governed by physical laws, is increasingly being biased by economical driving forces. Besides reliability criteria, the development of future transmission infrastructure must also take into account environmental constraints and energy-efficiency requirements.

The embedding of advanced HVDC Light systems in regional transmission networks is opening up new possibilities to enhance smart grid operations as the deployment of such solutions improves security and efficiency through its inherent controllability.

Infrastructure at its limits

On account of growing congestion, transmission grids are not always able to adequately facilitate the economic exchange of power between adjacent energy markets or enable the optimal use of generation resources. Congestion occurs when actual or scheduled power flows across critical transmission corridors are restricted below desired levels, either by physical capacity or by security restrictions. When such constraints limit the delivery of power from the most desirable generation sources to the load centers, grid operators must use more expensive or less efficient sources of generation.

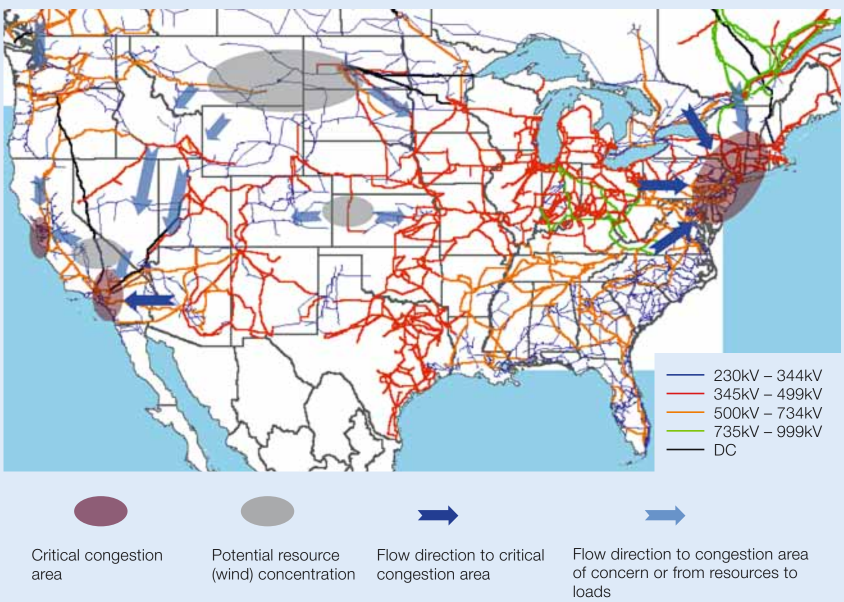
Furthermore, electric power grids are more and more integrating large-scale sources of renewable energy. The increased use of such intermittent sources, combined with the weak system interconnections in the areas where this generation is typically located, presents new challenges to managing the security of the power grid. With several gigawatts of offshore wind farms now in the advanced stages of planning, particularly in Europe, there is a need for reliable and robust power transmission to shore. In the United States, transmission has also been recognized as the largest single barrier to a significant expansion of wind energy and to achieving the target of it satisfying 20 percent of the nation's electricity supply by 2025 1. Thus, upgrading a transmission system is a key component of a sustainable energy future.

Today, more and more power is being generated further afield and transmitted over longer distances.

A robust and economical alternative

Incrementing power-delivery capability through the addition of conventional AC lines is increasingly becoming a challenge in meshed, heavily loaded AC grids. Environmental considerations are an important constraint in adding such capacity – often making overhead grid extensions impossible. AC expansion options, both overhead and underground, are furthermore often limited by voltage or transient instability problems, risk of increased short-circuit levels, grid responses and concerns over unacceptable parallel flows in the network. A further aspect is the cost of right-of-way for new transmission in urban areas.

1 In the United States, congestion of transmission lines has been recognized as the largest single barrier to a significant expansion of wind energy.



Source: National Electric Transmission Congestion Study, US DoE 2006

Footnote

[1] HVDC Light® is the ABB product name of an HVDC transmission system using voltage-source converters.

Moreover, there is a high demand for controllable transmission to effectively manage variable flow patterns and accommodate intermittent generation sources 2. Since its introduction in 1997, HVDC Light[1)] is increasingly emerging as an attractive solution to achieve the needed improvement in transmission capacity and the reliable integration of large-scale renewables while satisfying strict environmental and technical requirements.

HVDC Light technology

HVDC Light technology is based on voltage-source converters (VSC) using insulated-gate bipolar transistors (IGBT) [1]. The converters employ high-frequency pulse-width modulation (PWM) switching patterns and can thus control both active and reactive power, rapidly and independently of each other. HVDC Light systems can transmit power underground and under water over long distances. It offers numerous environmental benefits, including "invisible" power lines, neutral or static electromagnetic fields, oil-free cables and compact converter stations. The power ranges of HVDC Light have been improved rapidly 3. In the upper range, the technology now reaches 1,200 MVA for symmetric monopole schemes with cables. The power range can be increased to 2,400 MVA for bipole schemes with overhead lines [2]. One attractive feature of HVDC Light is that the power direction is changed by changing the direction of the current and not by changing the polarity of the DC voltage. This makes it easier to build an HVDC Light system with multiple terminals. These terminals can be connected to different points in the same AC network or to different AC networks. The resulting multi-terminal HVDC Light systems can be radial, ring or meshed topologies 4.

Enhancing smart transmissions

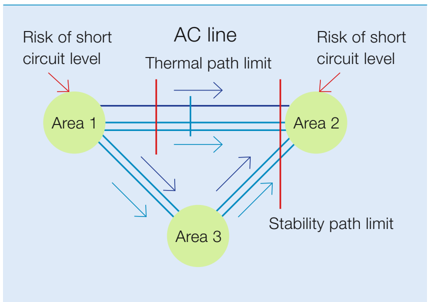
HVDC Light is ideal for embedded applications in meshed AC grids. Its inherent features include flexible control of power-flow and the ability to provide dynamic voltage support to the surrounding AC networks. Together with advanced control strategies, these can greatly enhance smart-transmission operations with improved steady-state and dynamic performance of the grid [3].

Enhancing regional interconnections

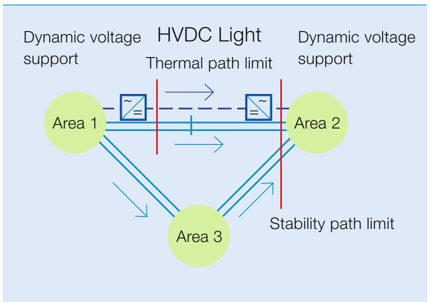
Under normal operating conditions, the power flow of an HVDC Light system can be scheduled on the basis of economic and system-security considerations. Furthermore, DC-link power flows can be dispatched in real time. This high controllability of power flow allows grid operators to utilize more economic and less pollutant generation resources, implement favorable bilateral transactions and execute effective congestion management strategies. Additionally, HVDC Light

2 HVDC Light improves the controllability of grids.

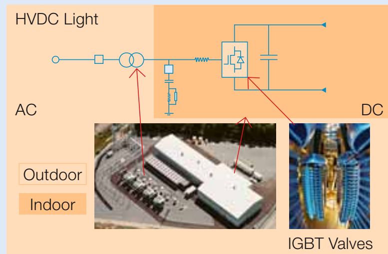
a An additional AC link between Areas 1 and 2 takes some of the strain, but cannot fully relieve the path via Area 3 of its overload.



b The controllability of the HVDC link enables it to carry the desired load and so relieves the other lines.



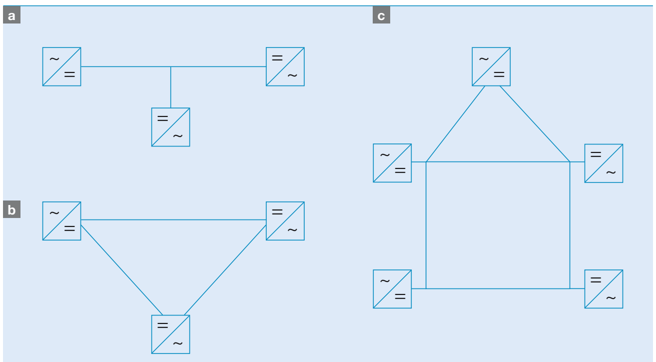
3 HVDC Light converter station and power range for symmetric monopole scheme with cables



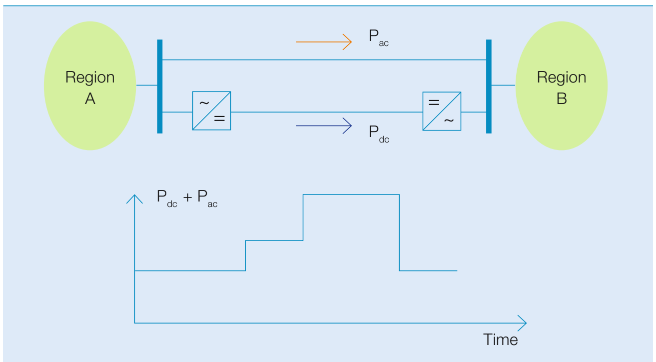
DC Voltage	580 A	1140 A	1740 A
± 80 kV	100 MVA	200 MVA	300 MVA
± 150 kV	190 MVA	370 MVA	540 MVA
± 320 kV	400 MVA	790 MVA	1210 MVA

HVDC Light converter station and power range for symmetric monopole scheme with cables

4 Flexible configuration of multi-terminal HVDC Light systems: radial a, ring b and meshed c.



5 The ability to strictly control power flow in an HVDC Light link means regional power flows can be managed according to contractual agreements, adding stability to the system.

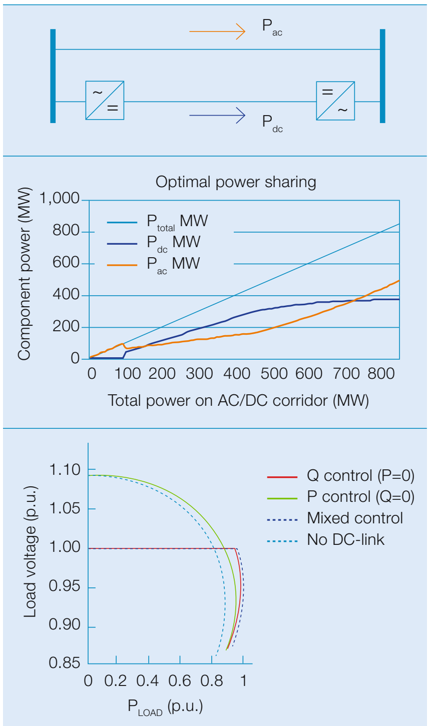


systems can be operated as merchant transmission facilities, similarly to merchant generators. The precise control of power flow through an HVDC Light system according to a contractual agreement simplifies the pricing of power transfers, billing, and preventing undesired flows 5.

Improving overall corridor utilization

In many cases, the capacity of the AC lines that comprise a transmission corridor cannot be fully utilized because of limitations to voltage or transient stability. One great advantage of HVDC Light is that adding such a link in parallel to AC lines can not only increase transfer capability, but it has been shown in studies that this increase can exceed the rating of the HVDC Light system. This gain is due to effective control of damping and dynamic voltage support for the parallel AC lines [4]. In addition, an optimal power-sharing principle can be implemented for a wide range of power-transfer levels to minimize the total energy losses of the hybrid AC/DC corridor. Depending on the operating condition of the hybrid AC/DC corridor, the control priority of the HVDC Light system could change from minimizing loss to maximizing power transfer. This adaptive control strategy can achieve a desirable balance between power transmission efficiency and corridor capacity utilization 6.

6 An HVDC Light link parallel to an AC link can be used to control the resulting hybrid AC/DC corridor, balancing transmission efficiency and corridor capacity utilization.



If a severe disturbance threatens system transit stability, HVDC Light can help maintain synchronized power-grid operation by fast power run-up or run-back control functions.

Integration of offshore wind farms

HVDC Light allows efficient use of long-distance land or submarine cables to integrate large-scale offshore wind farms into utility transmission grids 8. The main features of HVDC Light transmission for offshore wind power evacuation are:

- HVDC Light can fully comply with the grid code.
- Wind turbine generators need no longer be designed to fulfill the grid code. Their optimization can hence focus on cost, efficiency and robustness.
- An HVDC Light system can separate the wind farm from the AC network. Faults in the AC grid will not cause stress or disturbances on wind turbines, and faults in the wind farm will not affect the AC network.
- HVDC Light provides voltage and frequency control, and desired inertia can be emulated to enhance the stability of the AC network.

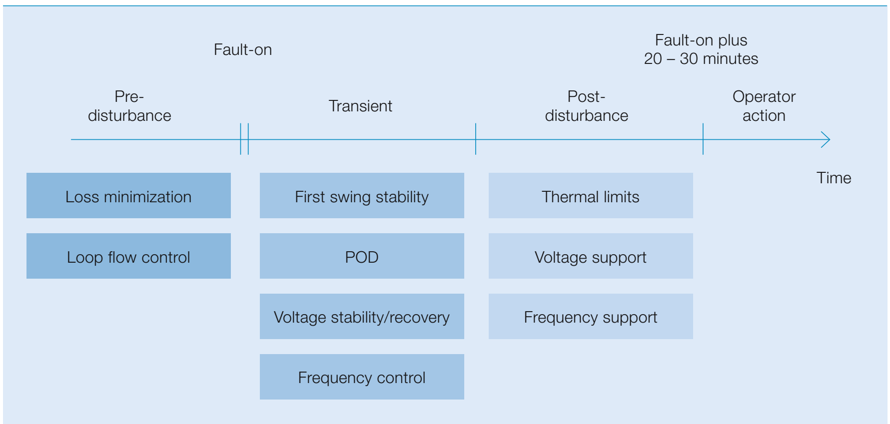
Performance under severe disturbances

Embedded HVDC Light systems can effectively improve the overall performance of the transmission grid during and following severe disturbances. A range of advanced application-control functions can be implemented to address different transient and post-disturbance problems 7.

First-swing stability

If a severe disturbance threatens system transient stability, HVDC Light can help maintain synchronized power-grid operation by fast power run-up or run-back control functions. During the fault phase, sufficient retarding power can be provided through the immediate reversal of HVDC Light power to limit rotor acceleration. Transient stability can also be improved by controlling the HVDC Light converters to provide supplementary reactive and voltage support after fault clearing.

7 Advanced control functions are features of HVDC Light.



8 HVDC Light permits the optimal integration of large-scale offshore wind farms into the grid.

Damping of power oscillations

HVDC Light can provide effective damping to mitigate electromechanical oscillations through the modulation of active and reactive power. A feedback signal such as that from active power flow measurement can be used to drive a supplementary damping control scheme. Alternatively, the SVC-like[2)] characteristic of the converter stations can be used to accomplish damping by injecting modulated voltage signals into the converter voltage control circuit. Logically, both P and Q could be modulated concurrently to achieve a more effective means of damping oscillations. HVDC Light can damp both local and inter-area modes of oscillations 9.

Voltage stability and voltage support

An HVDC Light system can be used to improve voltage stability in a variety of ways. By operating the converter as an SVC or STATCOM[3)] during and after the fault, dynamic voltage stabilization can be enhanced and voltage variations can be minimized. This greatly helps system recovery after a disturbance and reduces impacts on sensitive loads. HVDC Light provides countermeasures for both transient and longer-term voltage instability mechanisms. Fast modulation of reactive power provides dynamic var support for transient voltage stability. In case of longer-term instabilities, in which tap-changers and excitation system responses come into play, HVDC Light can help prevent voltage collapse via gradual P and Q modulation, including reducing active power transfer to increase reactive power capability at the terminal stations 10.

An HVDC Light system can be used to improve voltage stability in a variety of ways.

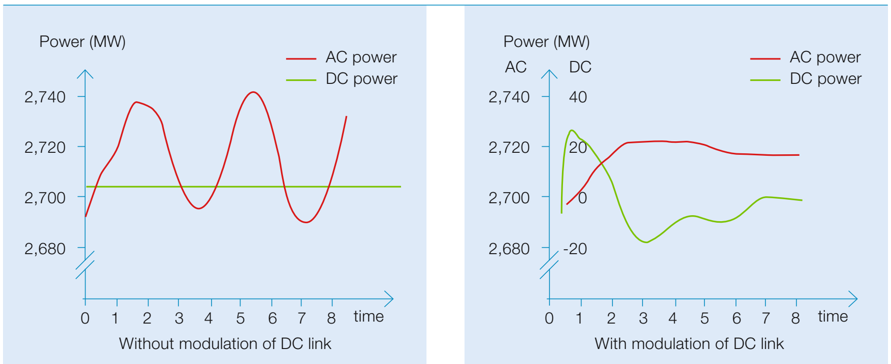
Frequency control and support

If the rectifier and inverter are connected to two unsynchronized power systems, one system can assist the frequency stabilization of the other using modulation functionality. In this control mode, the HVDC Light system adds or subtracts a contribution to the scheduled power order, proportional to the frequency deviation. Similarly, frequency support can be used to speed up restoration of islanded systems following a system breakup. HVDC Light provides the back-up active power required to assist in the frequency control of a neighboring island. At the same time, it acts as an additional load to the other island enabling a timely start up of its generators. HVDC Light frequency control and support can be coordinated with existing under-frequency load shedding schemes to limit frequency decay during a major system disturbance.

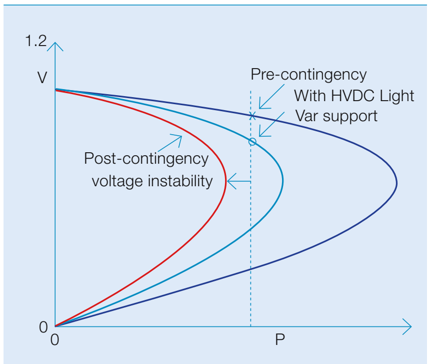
Black-start functionality

HVDC Light can aid in a black start or support restoration of the grid. The main features are a fast startup time, not requiring short-circuit capacity from the grid, the ability to work in pure "SVC-mode" to control voltage, and the ability to support frequency stability during restoration. Typically in a power plant, steam production has to be built up before load is connected to handle the cold-load pickup phenomena[4)]. However, with remotely available power and a dedicated control of HVDC Light, the grid restoration process can be significantly improved and the cold-load pickup phenomenon alleviated 11. Speed and robustness during the buildup are very valuable as the consequences

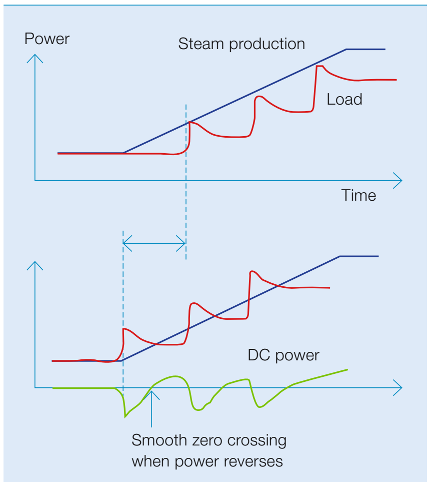
9 HVDC Light can be used to damp power oscillations.



10 HVDC Light's ability to modulate reactive power helps maintain voltage stability after a disturbance.



11 HVDC Light supporting the grid restoration process after a blackout



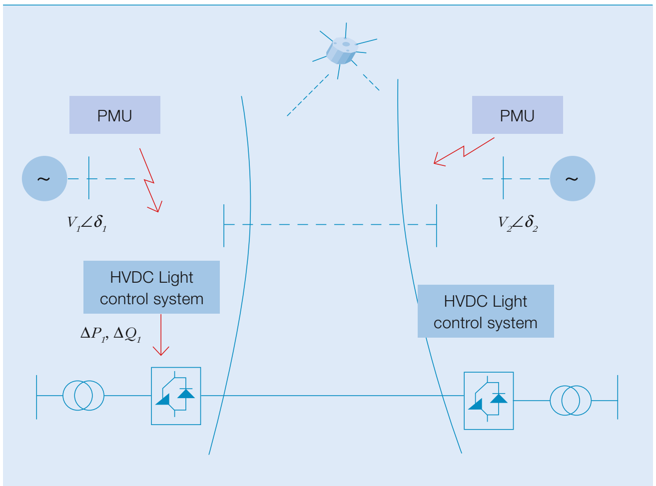
Footnotes

2) SVC: Static var compensator, a device typically made up of thyristor-switched capacitors, thyristor-controlled reactors and harmonic filters and used to inject or absorb reactive power in order to enhance voltage stability.

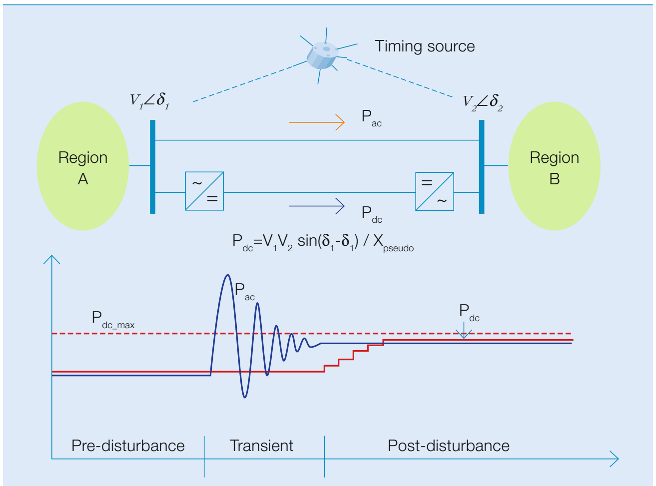
3) STATCOM: Static synchronous compensator, a device similar in function to an SVC but based on voltage source inverters.

4) Cold load pickup is the phenomenon that when bringing back power after an extended outage, the load is often found to be greater than it was before the outage. This can be caused by a combination of equipment-related effects (inrush currents of capacitors, magnetizing currents of transformers etc) and load-related effects such as the re-starting of stalled machinery and processes.

12 In combination with wide-area monitoring and wide-area control system (WAMS/WACS), HVDC Light can further enhance system stability and transmission efficiency.



13 HVDC Light emulating an AC link in a post-disturbance situation. This mode is useful for mitigating possible overloading of adjacent AC lines.



and costs of a blackout increase greatly with its duration.

Further improved performance

Using remote measurements, HVDC Light systems can effectively initiate control individually or cooperatively to improve transfer capability and to counter disturbances such as power oscillations. Such remote power grid information could come from a wide-area monitoring system (WAMS). WAMS, the measurement platform of smart transmission grids, consists of phasor measurement units deployed at geographically disperse locations in the system. GPS time-synchronized measurements of voltage and current phasors together with frequency and binary signals are collected and aligned by a phasor data concentrator. A wide-area control system (WACS) uses these wide-area measurement signals to provide auxiliary controls to power system devices. WAMS/WACS applications range from monitoring (such as state estimation and voltage security monitoring) to wide-area control such as the damping of power oscillations. It is envisioned that the performance of transmission grids can be further improved through the coordinated control of HVDC Light systems enabled by WAMS/WACS 12.

Emulating AC characteristics

In some cases, it is advantageous to use the DC link to emulate AC-line performance with respect to power-flow response to contingencies. The desired AC transmission characteristics allow the DC link to increase power transfer up to its maximum rating or reduce the transmitted power automatically in the post-disturbance period, mitigating possible overloading of adjacent AC lines 13. An embedded HVDC Light system can be autonomously controlled as a pseudo AC-line not requiring frequent schedule decisions from the system operator. This control mode is designed for situations where a centralized dispatch of the HVDC Light link is not a requirement. The set points of the DC link are determined as part of short-range operations planning, which determines the desired strength between the two connection points.

Transmission grid of the future

It is envisioned that the future transmission infrastructure will develop towards a hybrid AC/DC grid structure. In particular, embedded applications of HVDC Light, in combination with wide-area measurement and control systems, are set to significantly improve smart operation of the transmission grid.

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Smarter grids are more efficient

Voltage and Var Optimization reduces energy losses and peak demands

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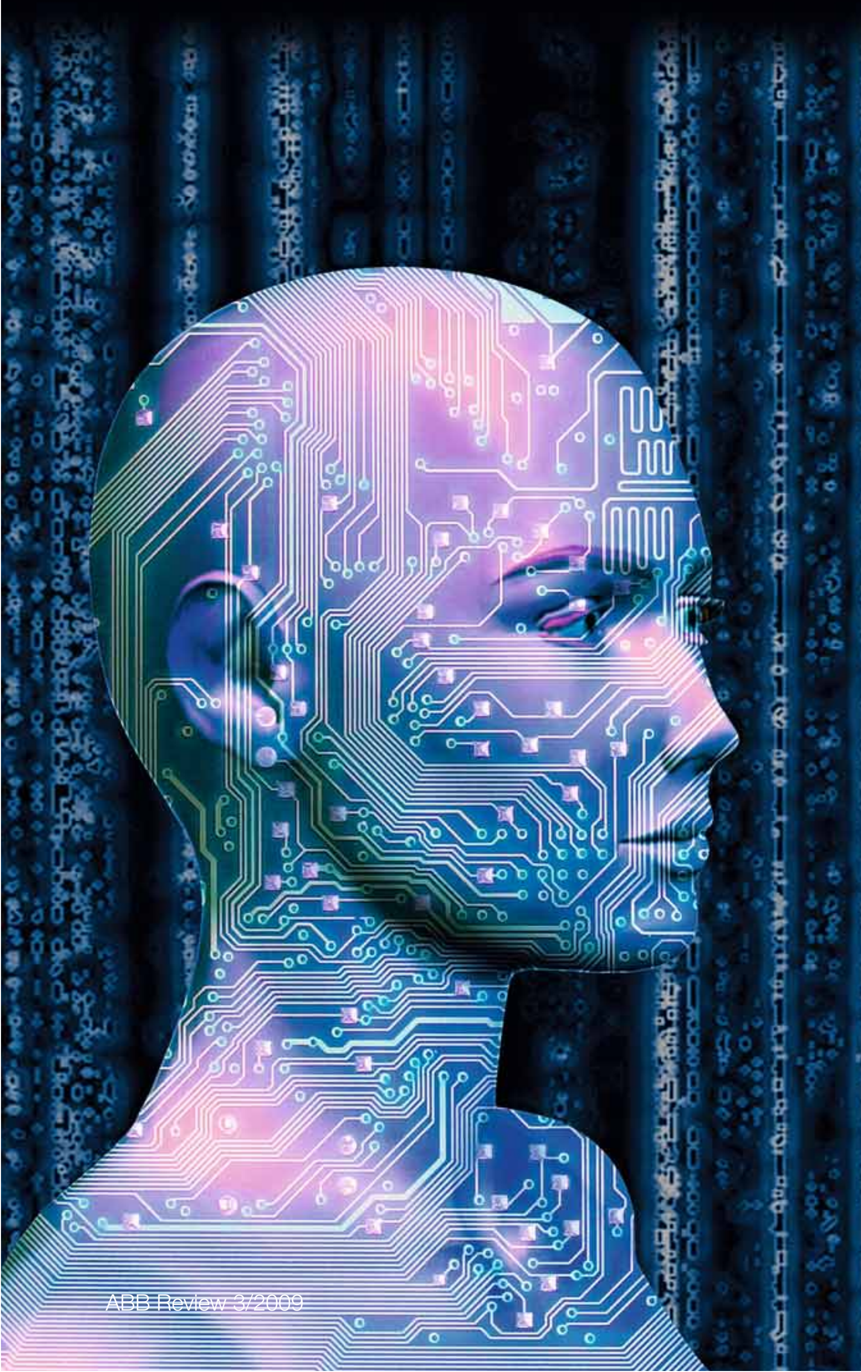


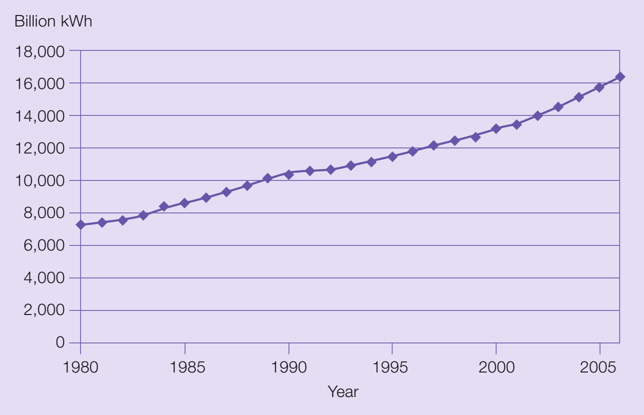
Have you ever wondered how much electric energy the world consumes or how much energy is lost on its way from the power plants to the end users? Have you wondered how much energy could be saved or greenhouse gas emissions could be cut if such energy losses were reduced by even a small amount? ABB is a world leader in the development of new technologies to help reduce electric energy losses and the demands made on electric distribution systems.

ABB offers a wide spectrum of products to increase energy efficiency and optimize demand management. Voltage and Var Optimization (VVO) is the latest addition to these applications. Differing from the traditional approach using uncoordinated local controls, VVO uses real-time information and online system modeling to provide optimized and coordinated control for unbalanced distribution networks with discrete controls. Electric distribution companies can achieve huge savings in the new frontier of energy-efficiency improvement by maximizing energy delivery efficiency and optimizing peak demand. VVO will help achieve these objectives by optimizing reactive resources and voltage control capabilities continuously throughout the year.

Transmission and distribution

The world has a huge appetite for electric energy, consuming thousands of billions of kilowatt-hours (kWh) annually, a figure that continues to climb as more countries become industrialized. The world's electric consumption has increased by about 3.1 percent annually between 1980 and 2006[1)], and is expected to grow to 33,300 billion kWh by 2030[2)] 1. The world's electricity consumption for 2008 was 16,790 billion kWh so by 2030 the world demand for electricity is expected to have almost doubled [1].

1 World electricity consumption (billion kWh)



Electric energy losses

Currently a significant amount (about 10 percent) of electric energy produced by power plants is lost during transmission and distribution to consumers. About 40 percent of this total loss occurs on the distribution network 2. In 2006 alone, the total energy losses and distribution losses were about 1,638 billion and 655 billion kWh, respectively. A modest 10 percent reduction in distribution losses would, therefore, save about 65 billion kWh of electricity. That's more electricity than Switzerland's 7.5 million people consumed in 2008 and equates to 39 million metric tons of CO_2 emissions from coal-fired power generation [1].

As the demand for electricity grows, new power plants will have to be built to meet the highest peak demand with additional capacity to cover unforeseen events. The peak demand in a system usually lasts less than 5 percent of the time (ie, just a few hundred hours a year). This means that some power plants are only needed during the peak load hours and their potential is utilized relatively infrequently. By active demand management on the distribution system, through demand response and VVO, the peak demand on the whole electric grid can be reduced. This eliminates the need for expensive capital expenditure on the distribution, transmission, and the generation systems. Even very modest reductions in peak demand would yield huge economic savings. For the United States in 2008, for example, the non-coincidental peak demand (ie, the separate peak demands made on the electrical system recorded at different times of the day) was about 790 GW. With every 1 percent reduction in the peak demand there would be a reduced need to build a 7,900 MW power plant 3.

Distribution system losses

The electric distribution network moves electricity from the substations and delivers it to consumers. The network includes medium-voltage (less than 50 kV) power lines, substation transformers, pole- or pad-mounted transformers, low-voltage distribution wiring and electric meters. The distribution system of an electric utility may have hundreds of substations and hundreds of thousands of components all managed by a distribution management system (DMS).

Most of the energy loss occurring on the distribution system is the ohmic loss[3)] resulting from the electric current flowing through conductors Factbox 1.

For any conductor in a distribution network, the current flowing through it can be decomposed into two components – active and reactive Factbox 2.

Reactive power compensation devices are designed to reduce or eliminate the unproductive component of the current, reducing current magnitude – and thus energy losses. The voltage profile[4)] on the feeders[5)], depending on the types and mixture of loads in the system, can also affect the current

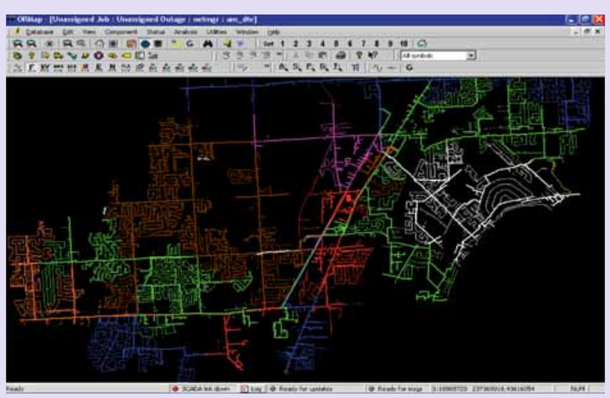
Footnotes

1) US Energy Information Administration, International Energy Annual 2006

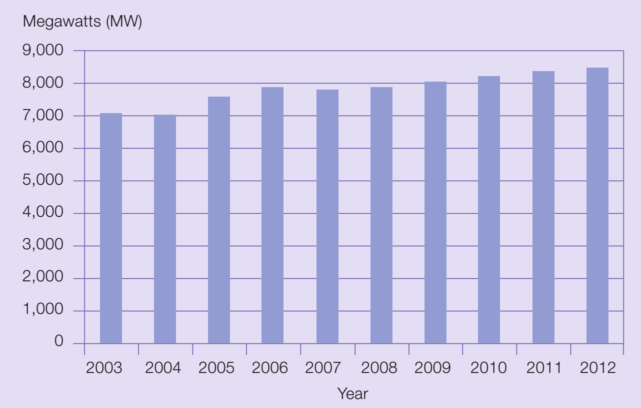
2) US Energy Information Administration, World Net Electric Power Generation: 1990–2030

3) The voltage drop across the cell during passage of current due to the internal resistance of the cell

2 Distribution system overview from network manager system (DMS)



3 Annual peak demand reduction of 1 percent for the United States



distribution, although indirectly and to a smaller extent, thus affecting power loss.

Voltage and var control devices

Voltage regulating devices are usually installed at the substation and on the feeders. The substation transformers can have tap changers, which are devices that can adjust the feeder voltage at the substation, depending on the loading condition of the feeders. Special transformers with tap changers called voltage regulators are also installed at various locations on the feeders, providing fine-tuning capability for voltage at specific points on the feeders.

Reactive compensation devices, ie, capacitor banks, are used to reduce the reactive power flows throughout the distribution network. The capacitor banks may be located in the substation or on the feeders.

> A modest 10 percent reduction in distribution losses would save about 65 billion kWh of electricity.

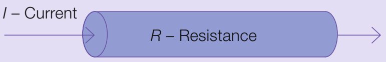
Traditional control verses VVO

Traditionally, the voltage and var control devices are regulated in accordance with locally available measurements of, for example, voltage or current. On a feeder with multiple voltage regulation and var compensation devices, each device is controlled independently, without regard for the resulting consequences of actions taken by other control devices. This practice often results in sensible control actions taken at the local level, which can have suboptimal effects at the broader level.

Ideally, information should be shared among all voltage and var control devices. Control strategies should be comprehensively evaluated so that the consequences of possible actions are consistent with optimized control objectives. This could be done centrally using a substation automation system or a distribution management system. This approach is commonly referred to as integrated VVO. The accelerated adoption of substation automation (SA), feeder automation (FA) technology, and the widespread deployment of advanced metering infrastructure (AMI) have over the last few years laid the foundations for a centralized control approach, by providing the

Factbox 1 Energy losses

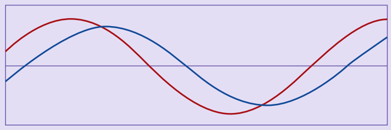
The energy loss is due to the resistance in the conductor. The amount of loss is proportional to the product of the resistance and the square of the current magnitude. Losses can be reduced, therefore, either by reducing resistance or the current magnitude or both. The resistance of a conductor is determined by the resistivity of the material used to make it, by its cross-sectional area, and by its length, none of which can be changed easily in existing distribution networks. However, the current magnitude can be reduced by eliminating unnecessary current flows in the distribution network.



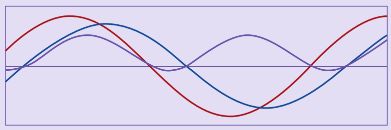
$$Loss = I^2 R$$

Factbox 2 Active and reactive power

The voltage and current waveforms on an AC power line are typically sineshaped. In an "ideal" circuit, the two are perfectly synchronized. In the realworld, however, there is often a time lag between them. This lag is caused by the capacitative and inductive properties of attached equipment (and of the lines themselves).

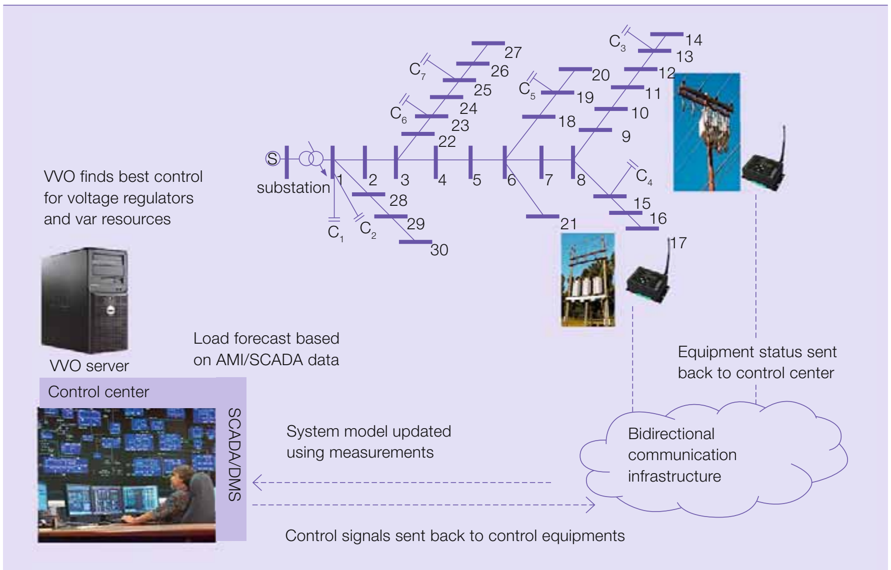


The momentary flow of power at any time is the product of the momentary current and voltage. The average value of this power is lower than it would be without the time lag (for unchanged magnitudes of voltage and current). In fact the power even briefly flows in the "wrong" direction.



The greater the time lag between the curves, the lower the energy delivery. This lag (expressed as phase angle) should thus be minimized. The average energy delivery per time unit is called active power (measured in W). Reactive power (measured in VAr) is a measure of the additional power that is flowing on the line but cannot be put to effective use.

4 A schematic showing how VVO works



Footnotes

4) Voltage profile refers to the spatial distribution and voltage magnitudes at different locations or nodes throughout the network.

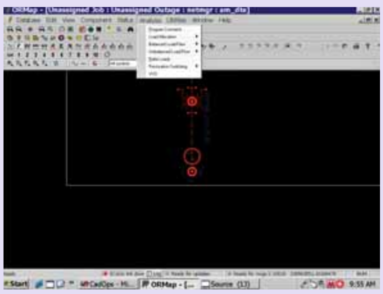
5) Any of the medium-voltage lines used to distribute electric power from a substation to consumers or to smaller substations.

necessary sensor, actuator, and reliable two-way communications between the field and the distribution system control center. Until recently, however, a key technology has not been available that can take advantage of advanced sensing, communication, and remote actuation capabilities that can be used to continually optimize voltage and var. Prior generations of VVO technologies have been hindered by their inability to model large and complex utility systems, and by their unsatisfactory performance in solution quality, robustness and speed.

How does VVO work?

VVO is an advanced application that runs periodically or in response to operator demand, at the control center for distribution systems or in substation automation systems. Combined with two-way communication infrastructure and remote control capability for capacitor banks and voltage regulating transformers, VVO makes it possible to optimize the energy delivery efficiency on distribution systems using real-time information 4.

5 VVO prototype screen capture



6 VVO compared to prior method

Prior method	ABB VVO capability
Single phase equivalent model	Multi-phase, unbalanced model
Balanced load	Unbalanced load
Single source	Multi-source
Radial system	Meshed system
Ganged control	Unganged control
Academic system size	Real utility system size
Offline performance	Online performance
Heuristic	Optimization theoretic

VVO attempts to minimize power loss, demand, and voltage/current violations[6] in meshed, multi-phase, multi-source, unbalanced electric distribution systems.[7] The control variables available to VVO are the control settings for switchable capacitors and tap changers of voltage regulating transformers.

Main benefits of VVO

The main benefits of VVO for distribution system operators are:

- Improved energy efficiency leading to reduced greenhouse gas emissions.
- Reduced peak demand and reduced peak demand cost for utilities

General problem definition for VVO

VVO must minimize the weighted sum of energy loss + MW load + voltage violation + current violation, subject to a variety of engineering constraints:

- Power flow equations (multi-phase, multi-source, unbalanced, meshed system)
- Voltage constraints (phase to neutral or phase to phase)
- Current constraints (cables, overhead lines, transformers, neutral, grounding resistance)
- Tap change constraints (operation ranges)
- Shunt capacitor change constraints (operation ranges)

The control variables for optimization include:

- Switchable shunts (ganged or unganged[8])
- Controllable taps of transformer/voltage regulators (ganged or unganged)
- Distributed generation

Technical challenges

VVO in essence is a combinatorial optimization problem with the following characteristics:

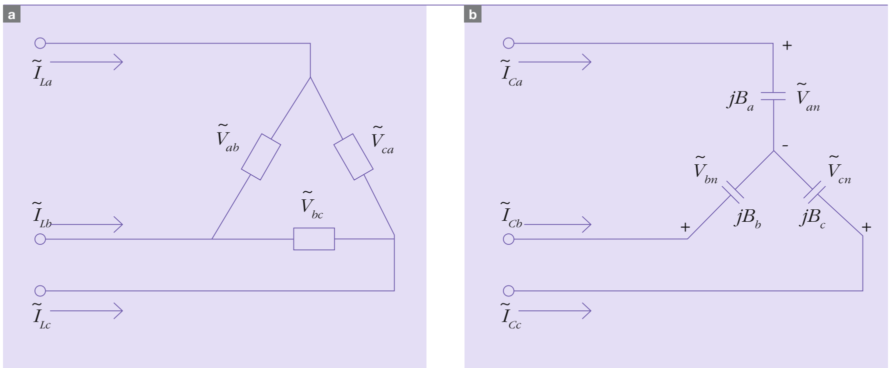
- Integer decision variables – both the switching status of capacitor banks and the tap position of regulation transformers are integer variables.
- Nonlinear objective being an implicit function of decision variables – energy loss or peak demand are implicit functions of the controls.
- High dimension nonlinear constraints – power flow equations numbering in the thousands in the multi-phase system model.
- Non-convex objective and solution set.
- High dimension search space – with un-ganged control, the number of control variables could double or triple.

Anyone who has tackled optimization problems will tell you that mixed-integer nonlinear, non-convex (MINLP-NC) problems are the worst kind to solve (See "Simply the best," *ABB Review* 1/2009, page 54).

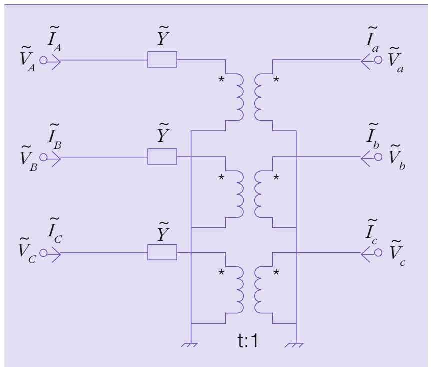
VVO improves energy efficiency and reduces greenhouse gas emissions. It reduces peak demand, which reduces peak demand cost for utilities.

The major challenge is to develop optimization algorithms that are efficient for large problems. Since a certain amount of computation (ie, CPU time) is needed to evaluate the loss and demand for a single specific control solution (a single functional evaluation), an algorithm that requires fewer functional evaluations to find the optimal solution is generally regarded as more efficient than one that requires more functional evaluations to achieve the same objective. In the case of VVO, a single function evaluation involves solving a set of nonlinear equations, the unbalanced load flow, with several thousand state variables. The nonlinear, non-convex combinatorial properties of the VVO problem coupled with high dimensionality (large number of state variables) are the reasons why VVO has been a long standing challenge in the industry. In the last decade many in the research community have increasingly begun to resort to meta-heuristic approaches (eg, generic algorithms, simulated annealing, particle swarming, etc) to avoid the modeling complexity. The meta-heuristic approach has shown limited academic value in solving small-scale problems and in offline applications where online performance is not required.

7 Delta-connected load a and wye-connected capacitor bank b



8 Wye-wye-connected transformer model



ABB's next generation VVO

ABB developed a new-generation VVO in 2008 capable of optimizing very large and complex networks with online application speed. An innovative solution methodology enables the detailed and accurate modeling of the distribution system components and connections. It rapidly identifies the optimal voltage and var operation strategy from millions, if not billions, of operation possibilities using advanced mixed-integer optimization algorithms.

A prototype has been developed, which integrates directly with ABB's DMS. The prototype performed very well in the lab with distribution network models of a real utility system. Both the solution quality and speed robustness met or exceeded design criteria for online applications 5.

ABB developed a new generation VVO in 2008 capable of optimizing very large and complex networks with online application speed.

The size of the test systems range from 1,600 to 7,800 nodes and 1,600 to 8,100 branches per circuit. Optimization improved the loss from 2.5 percent to 67 percent[9] and demand reduction from 1.4 percent to 5.8 percent.[10]

The following table is a brief summary of the key features that differentiate ABB's VVO technology from prior methods 6.

To accurately model a distribution network's behavior a detailed network model is used. Phase-based models[11] are used to represent every network component. Loads or capacitor banks can be delta 7a or wye connected 7b.

Transformers can be connected in various delta/wye and various secondary leading/lagging configurations with or without ground resistance, with primary or secondary regulation capability 8.

Both voltage and var controls can be ganged or unganged. The method works on radial as well as meshed networks, with single or multiple power sources. Voltage controls are enforced for each individual phase, using phase-to-ground or phase-to-phase voltage, depending on the connection type of the load.

One smart technology at a time

With the accelerating deployment of advanced sensor network, smart metering infrastructure, and remote control capability, there is a growing need for smart applications like VVO that optimize the operation of the distribution system. The development of the next generation of VVO technology is a demonstration of ABB's ability to bring smart grid technology to its customers.

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Footnotes

6) Voltage/current violations refer to the undesirable excursion from normal operating range, eg, current exceeding the maximum limit safe for a given conductor type, or voltage exceeding a limit unsafe for the consumer or falling short of a limit needed for normal operation for end users.

7) A distribution system model may have the following features: meshed (looped, with multiple paths between some nodes), multi-phase (each of the A, B, C phases explicitly modeled, rather than modeled as a single phase), multi-source (a load can get electric supply from multiple sources), unbalanced (asymmetric construction, such as a single-phase feeder, and/or asymmetric loading, ie, unequal loading on each phase)

8) Ganged control means multiple phases operated in unison, and unganged control means each phase operated independently.

9) The amount of loss reduction depends on the controllable voltage and var resources in the system, the system loading condition, and the initial control strategy.

10) The amount of demand reduction depends on the factors that affect loss reduction as well as the load model. For 100 percent constant load, demand reduction can only be achieved through loss reduction.

11) Exact component model includes the information of all existing phases.

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[1] *CIA Online Factbook.* Retrieved June 2009 from http://www.cia.gov/library/publication/the-world-factbook/

Information, not data

Real-time automated distribution event detection and notification for grid control

Mirrasoul J. Mousavi, Vaibhav D Donde, James Stoupis, John J. McGowan, Le Tang

Knowledge is power, or so an old dictum teaches us. Certainly, to be able to direct or control any system, accurate and up-to-date knowledge of its current status is invaluable. The plenitude of data that is necessary to control a complex system is well illustrated by the vast quantity of measurements that are available in the control room of an electric grid.

But how does one improve such a control system in view of rising demands and expectations? Common wisdom would suggest that this requires even more data, ie, more measurement devices collecting more measurements (including distribution feeders and the "last mile" to the customer) and transmitting them to the control room. Much of the effort that is being put into preparing the smart grid that will assure the power supply of tomorrow is consequently focused on such smart measurement devices.

This, however, is only part of the story. Without a proper strategy for handling and evaluating such input, this approach will lead to a "data tsunami": The control room will be inundated with measurements, making it difficult to distinguish the relevant from the irrelevant. The answer lies in pursuing information, not data. Quality information involves delivering the right facts to the right place at the right time. Only by achieving this can knowledge truly assure and secure the flow of reliable power.

The protection, control, and monitoring of power systems involve making numerous decisions. These occur over a broad period and on time scales ranging from the split-second decision to trip a line or feeder for protection reasons, to issuing an alert after months of monitoring an incipient failure. System operators are often the ultimate human decision makers who still benefit from some form of information from multiple sources across a utility system. Their involvement in direct decision making decreases in situations where there is an advanced penetration of automation technologies, as occurs in substation automation systems. The industry-wide move toward smart grids is demanding more automation down to the last mile and involving distribution feeders and end customers. The ultimate goal is to enable power system protection, control, and monitoring to operate in a closed-loop mode, so becoming an enabler for a self-healing grid: a frequently sought attribute of a smart grid. This article looks at an enabling technology to help achieve such an ambitious goal. It looks at the provision of real-time and automated response to distribution feeder events and anomalies.

The grid of the future

Smart grids require three fundamental elements: data, information/intelligence, and communications. The data element is supplied by sensors and sensor systems including intelligent electronic devices (IEDs) in feeders and switch controllers. The intelligence element is provided by digital processors that are instructed to perform certain operations on data through algorithms. Finally, the communications element is required to deliver the derived intelligence to the right person/device, in the right format, and at the right time. These three elements are indeed the building blocks of current control and automation systems. They do, however, require a dramatic boost in functionality, performance, and coverage (down to the last mile and including end customers). More importantly, they require an infusion of intelligence into every system and device, ranging from a local human-machine interface to a broadband IP or fiber-optic network 1.

The grid of the future requires three fundamental elements: data, information/intelligence, and communications.

Automation technologies and the proliferation of IEDs across the transmission and distribution systems pave the way for the availability of more data and hence the improvement of the decision making process. However, the lack of application tools and automated data analyzers (ie, intelligence algorithms) hinders the effective use of data.

The promise of a smart grid cannot be fulfilled purely by continuing the digitization of the power system or expanding the communications infrastructure. At the core of any intelligent system there must be a “brain” for the processing of the data it receives. Additional sensing and measurement points alone do not address this problem but rather contribute to the overflow of data. What is needed is an extraction of the information that is embedded in the raw measurements. The decisions based on this information do not have to be made exclusively in a central location or by human agents. However, for decisions to be made, quality information needs to be collected across the system. This means that as many tasks as possible need to be automated to free up human resources to perform the tasks that cannot and should not be automated. Overloading human operators with unnecessary data can lead to the most relevant information being lost and result in suboptimal decision making.

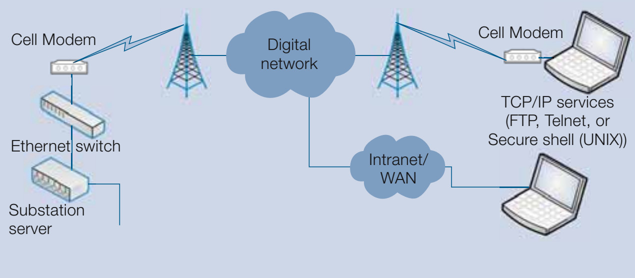
The move toward smart grids will nevertheless mean more sensors and measurement points to bring visibility to every component and down to the last mile 2. As a result, more and more data must be collected and processed. The utility environment of today is overflowing with the mass of data already being harvested by existing systems. If the addition of new data points 3 is not to lead to a “data tsunami,” the data-to-information conversion process must be optimized at every step of its path. This means that a conversion that can be performed at a lower level should not have to be performed at a higher level. The last thing that system operators want is additional data requiring avoidable manual processing.

Focusing on distribution operations, there is a substantial need for simpler and better optimized operations and maintenance, which should be based on data received from various IEDs installed throughout the grid. It is also

1 Sensors and communications must be extended into the feeder lines for information on the system status to be made accessible.

a Current-sensor head
b Integrator box
c PT (potential transformer)
d Main box including data-acquistion unit. modem and UPS (uninterruptible power supply)

2 Communications infrastructure is an enabler for smart control.



desirable to be able to automate the analysis tasks and transform raw data into actionable information, upon the basis of which utility dispatchers and crews can make decisions. Conventionally, the records from these IEDs are often analyzed manually by trained experts on limited occasions. The overwhelming nature of the manual analysis of data and the issues of an aging workforce connected to today's utility environment highlight the importance of being able to perform these tasks via computer with little or no human intervention. More importantly, providing this information in real time creates an enormous added value for the utilities by improving reliability and reducing the duration of customer outages.

Levels of intelligence

Smart grids demand solutions and analysis tools to enable electric utilities to receive the right information and distribute it to the right people at the right time. As the utilities face shrinking budgets and reduced workforces, the integration of automatic event analysis into utility systems becomes imperative.

The overall theme of these changes is "data transformation into actionable information.. With reference to 4, this process can be executed in multiple levels across a utility system.

- Level 0 is at the feeder level, which includes "box" intelligence only. The transformation is typically done by embedding the intelligence into feeder IEDs such as switch controllers and stand-alone monitors.
- Level 1 is at the substation-box level. It includes applications/algorithms applicable to each individual substation IED.
- Level 2 is at the substation-system level, it includes applications/algorithms for extracting information from multiple IEDs via a substation computer or a master workstation.
- Level 3 is at the enterprise level. It includes the data warehouse/historian along with the control room applications/algorithms applicable at the aggregate utility level.

The majority of events on feeder laterals is not reported to operations groups, as the current protection and monitoring practices are limited to events on the main line.

Of course, one could add a level 4 in which data/information from multiple utilities are aggregated and processed for greater intelligence and applications on a regional or national level.

As the flow of data/information moves away from field devices and to the right in 4, the ratio of raw data to information is reduced. In other words, more and more information is made available by utilizing embedded intelligence at every step to avoid data proliferation in the next upper level.

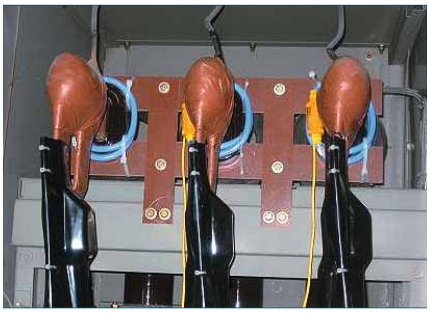
Distribution issues

Due to the historical lag in the adoption of automation technologies, the need for automation and embedded intelligence is more pronounced in distribution operations than anywhere else on the electric grid. Distribution utilities are more than ever expected to do more with less, and system automation is a practical way of achieving this. Existing architecture and systems provide a great quantity of data from a subset of key components through protective relays and IEDs. The movement toward traditional substation and feeder automation by utilities has resulted in large volumes of data, but the corresponding information capability has not received due attention. Specifically, analytical data, eg, digital fault records, target records, trends, load profile, power quality, sequence of events and event data, eg, lateral faults, equipment failures, have not received the necessary focus, especially because substation automation was considered the domain of protection engineers. Moreover, the majority of events on feeder laterals is not reported to operations groups, as the current protection and monitoring practices are limited to events on the main line. In many cases, utilities must rely on customer calls to identify and locate trouble areas down the feeder main and its laterals. Practical tools are needed to analyze feeder event data from these areas. Some utilities have migrated from traditional substation automation to a more integrated collection of operational, equipment-failure, and event data. With this additional data comes the need for specialized analysis tools for automation to enable smart grids.

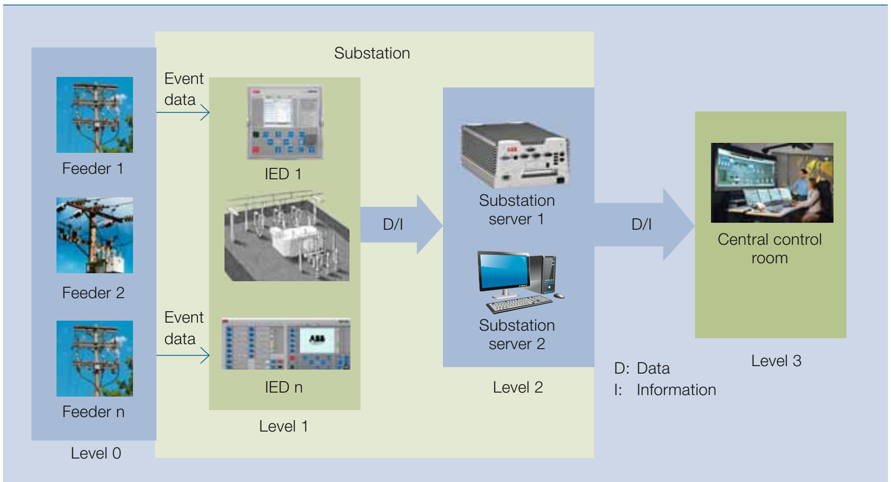
ABB's solutions

Distribution feeders, whether overhead or underground, experience faults, in-

3 Retrofit Rogowski-coil sensors



4 The four levels of intelligence in data handling



cipient failures, temporary events and transients. Objective analysis and correlation of these various types of events - some of them catastrophic - enable utilities to proactively address feeder events rather than merely being able to react to them. The logical initial step to achieve this is to enhance the IEDs and substation server to include the most valuable event analysis applications. The solution offered is therefore to address the need for transforming event data into actionable information upon which system operators and dispatch crews can act proactively.

Areas that can benefit significantly from feeder-level real-time intelligence include outage detection, confirmation, notification, and crew dispatch.

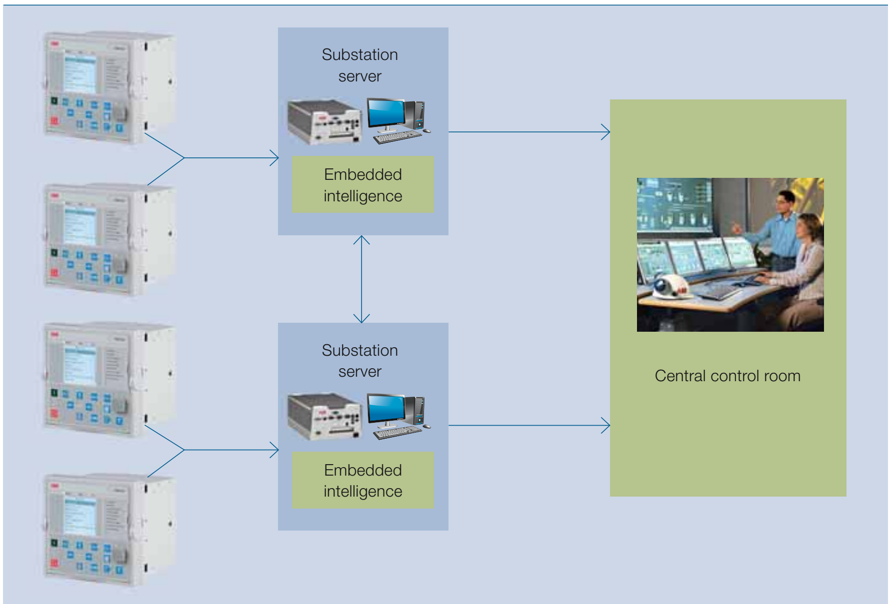
The ability to proactively address feeder problems and respond as quickly as possible to outages and feeder failures, along with the tendency toward predictive maintenance, will be a significant contributor to the adoption of smart grids. Today, maintenance schedules for assets are performed on a pre-programmed basis and do not take into account specific intelligence on feeder events or health. Thanks to such additional analysis, the operations and maintenance departments of a smart grid will have the ability to respond more quickly, send the right crew, assess the risks and proactively address feeder problems. The planning departments in turn will achieve better information for feeder upgrades and enhancement projects.

It was shown in 4 how intelligent event detection and analysis algorithms may reside at different levels in the supervision and control hierarchy. The feeder IEDs can host algorithms that use local data to detect anomalies in the power system behavior and identify an abnormal situation (such as a fault). Based on their local analysis, they can take an appropriate action (such as tripping appropriate circuit breakers or switches) or forward the fault/event information to the next higher level of the hierarchy (which can be a substation computer) 5. This essentially minimizes the amount of data that must be sent up to the substation or DMS at the control center and has the additional positive impact of reducing the communications bandwidth required.

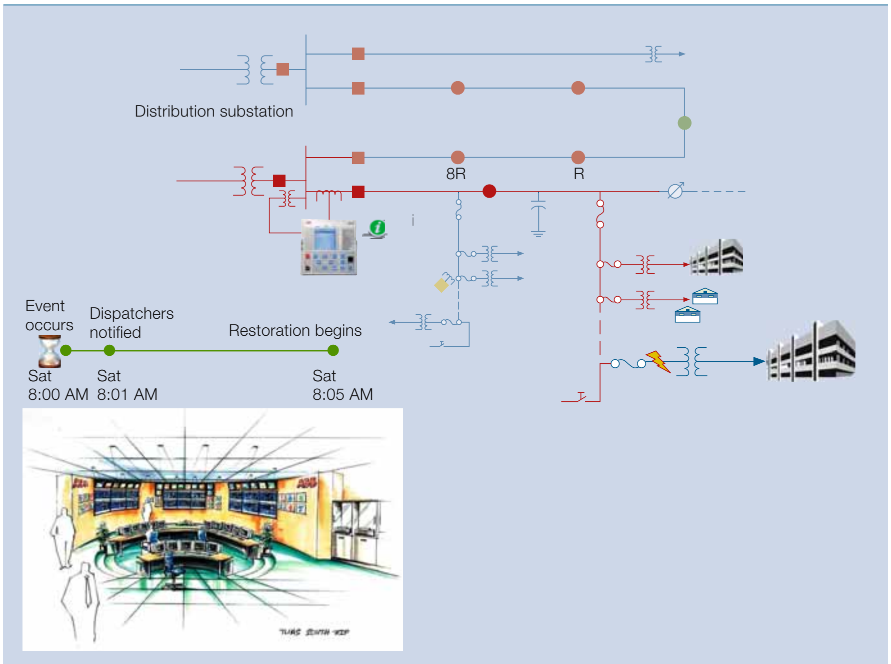
One way to achieve this is to host the fault/event detection functionality on the substation computer. The benefit is that it provides more visibility of system activity at the feeder level (information that is unavailable with conventional protection and control IEDs). This information can be utilized to take actions that address the issue at hand more precisely.

Along the same lines, the event-detection functions can be hosted at the DMS level. Each of these solutions comes with its own benefits and limitations. These need to be carefully evaluated by the user to achieve optimal net benefit from the chosen design. The solution selected can be tailored

5 Embedded intelligence can take actions locally or foreward the notification to the next higher level.



6 Reduction of outage duration through real-time event detection and notification



on the basis of complexity, scalability, cost, communications options and customer preference.

Benefits

Areas that can benefit significantly from feeder-level real-time intelligence include outage detection, confirmation, notification, and crew dispatch. Electrical faults and the resulting outages on distribution feeders result in loss of revenues and adversely affect customer satisfaction and reliability. Such events contribute significantly to customer-minutes-out and ultimately impact the utility's performance. For example, a certain class of feeder faults does not cause the substation breaker to operate and therefore does not generate a reportable SCADA (Supervisory Control and Data Acquisition) event. As a result, the utility has to rely on customer calls to notify it of sustained outages impacting the customer's premises. This type of reactive response can become a thing of the past if appropriate technologies are deployed 6.

The technology can help detect incipient faults that are on the verge of escalating into full-grown failures.

Real-time and automated event analysis/detection and notification reduce the time required to respond to an outage and provide an advance notification of a sustained outage before customer calls start overflowing the call centers. By enabling the utility to address the problem before an outage report is received, or by avoiding the outage altogether, this smart grid functionality has the potential to reduce customer-minutes-out that negatively affect both the utility's performance metrics and customer productivity. Furthermore, it improves the utility's preparedness for outage calls and provides an effective tool to confirm the reported nature of the incident. In particular, the technology applied to underground feeders notifies the utility of the cable faults that are cleared by the protection device – typically a fuse – along the feeder. More importantly, it can help detect incipient faults that are on the verge of escalating into full-blown failures, thereby optimizing the annual maintenance expenditures on cable replacements. This can be done using direct evidence of feeders with high activity of temporary underground faults.

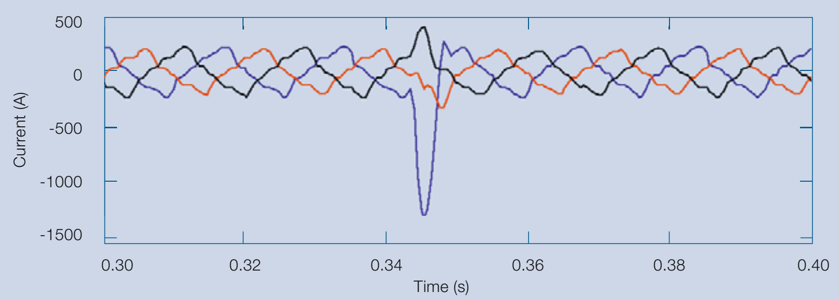
It is advantageous from the economic perspective to position this intelligence in the same location as the traditional intelligence, eg, in a substation or intelligent switch rather than placing it specially on feeder lines. Being able to learn of events to the "last mile" at the substation presents a very cost-effective moinitoring solution

Feeder event examples

A certain class of incipient faults in underground cables results from moisture/water intrusion and subsequent intermittent self-clearing arcing in splices [1]. The fault clears itself quickly due to vapor pressure, with the result that protection devices do not come into operation – hence the description of these events as self-clearing. Since underground cables very often form a major part of a utility's assets, monitoring and recognition of these failures is essential for the pro-active management of faults and predictive maintenance. Continuous monitoring and automated data analysis with embedded intelligence is vital for achieving this smart grid functionality.

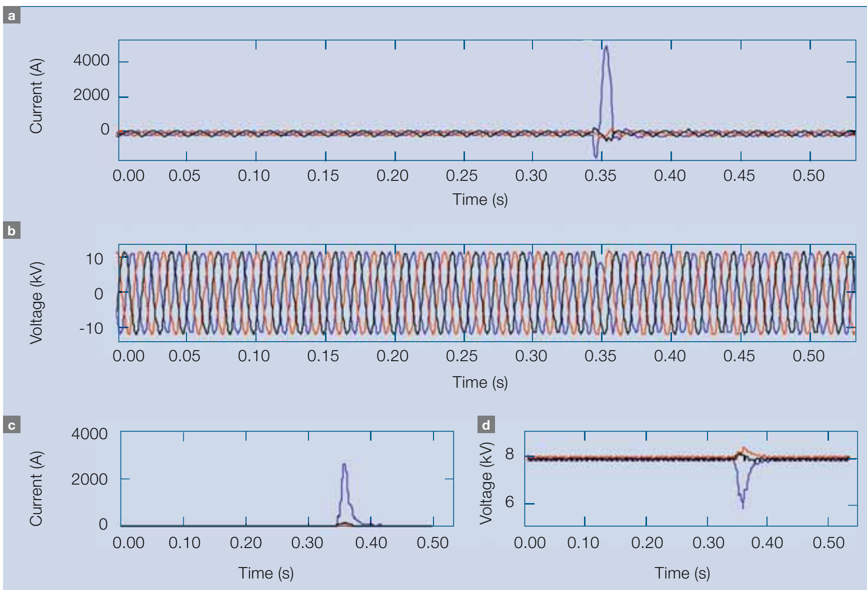
An example of an incipient failure that occurred in a utility feeder is shown in 7. The fault peaked at 1,287 A and

7 Example recording of an incipient failure. This was a self-clearing fault that did not result in any immediate outage.



Subsequent monitoring recorded 140 additional cases of similar incipient failures until the catastrophic failure nine months later that blew a 65A fuse 8.

8 View of the catastrophic failure following on from 7, showing three-phase currents a, voltages b, current-phasor analysis c and voltage-phasor analysis d.



lasted 0.22 cycles without causing any outage or fuse operation. Therefore, no corresponding record was registered in the outage management data. Subsequent monitoring recorded 140 additional cases of similar incipient failures until the catastrophic failure nine months later that blew a 65 A fuse. The current and voltage views for this final event can be observed in 8, showing a peak fault current of approximately 5,000 A. Between the first incident and the catastrophic failure, there were similar cases of incipient faults with current spikes varying between 1,000 A and 3,000 A in magnitude and with both positive and negative polarity. None of these events left a trace in the outage data nor led to any customer interruption.

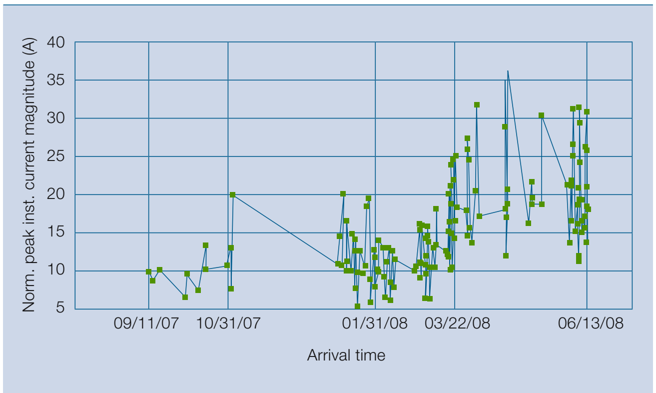
Subsequent trend analysis and quantization revealed a progressive development in normalized peak faults toward the eventual fault time 9. The normalized peak increased to almost three times its initial value by the end of the monitoring period. This observation indicates that the cable splice integrity was being degraded further with every instance of a reoccurring incipient fault and arcing.

This real-time feeder intelligence can raise the value of existing sensor installations and is easy to retrofit. It unleashes the potential of substation data that is already being recorded by digital protection systems but remains underutilized. In this way, it provides an "always-on" monitoring capability. Additionally, it also demonstrates that it is feasible to pick up the signature of, and predict a unique class of feeder faults that develop over time from a reoccurring incipient stage to a full-blown failure.

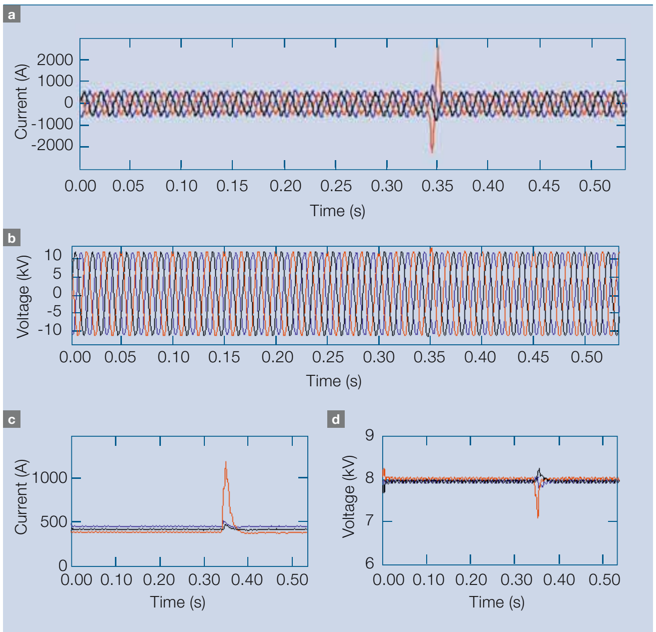
Similar analysis can be performed on other types of feeder events, most notably permanent underground cable failures.

An example of a cable failure on the primary feeder lateral that was cleared by a 40A fuse is shown in 10. It shows the current 10a and voltage 10b raw-data waveforms, as well as the phasor magnitude plots 10c 10d. The sub-cycle current spike can be seen in the current plots. Using embedded intelligence and automated analysis, this

9 Fault current trend leading up to the failure of 8



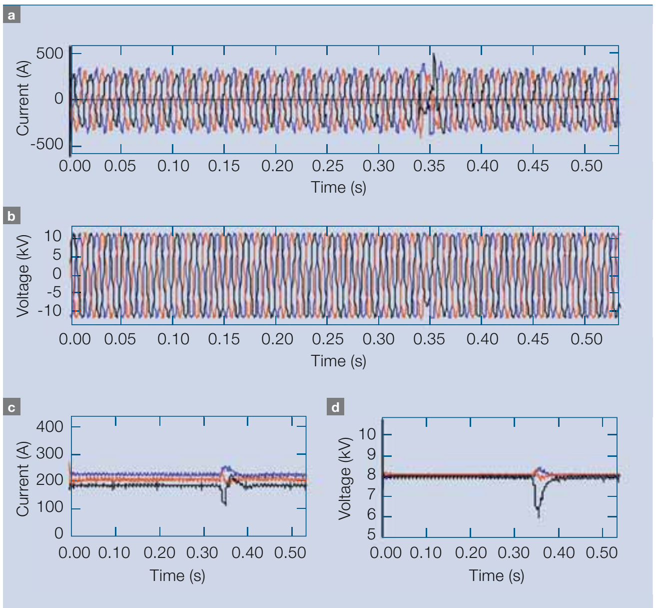
10 Waveforms a–b and phasor-magnitude c–d plots for an underground cable failure



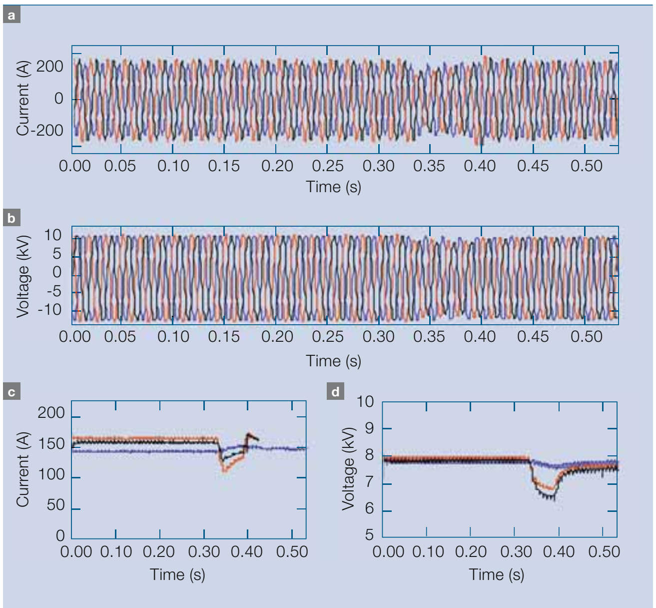
Transmission events propagate through the transmission grid and can impact the distribution grid as well.

Transmission and distribution

11 Current a and voltage b waveforms and the corresponding current c and voltage d phasor-magnitude plots for an underground cable failure on an adjacent feeder



12 Current a and voltage b waveforms and the corresponding current c and voltage d phasor-magnitude plots for an upstream transmission fault



event was detected and confirmed with the utility data.

Furthermore, such processing can also detect a failure on the adjacent feeder. An example of an underground cable failure on a feeder adjacent to the monitored feeder is shown in 11. The plots show a voltage dip and its effect on the current waveform.

Finally, certain transmission and generation events can also be observed and analyzed at the distribution level. An example of an upstream fault on the transmission system is shown in 12. The plots show current and voltage dips on multiple phases.

The road to tomorrow's grid

The path toward achieving a smart grid is about modernizing the century-old electric grid to meet or exceed the needs of the digital society and promote customer participation. This is accomplished in part by providing or enhancing data acquisition, management, transport, interpretation, and automation systems across the board from end-customer premises to conventional and renewable power plants. The key area for this modernization is the distribution grid and the last mile, which are undergoing a radical change in relation to their original design and purpose. Means of communication are needed for enhanced protection, control, and automation with various levels of intelligence to process the utility data and act intelligently, confidently and timely.

Real-time and automated event detection in distribution grids, as well as near real-time notification, are prerequisites of the ultimate goal of moving to closed-loop mode in protection, control and monitoring. Such a vision of the future can be fulfilled by acquiring useful raw data and deploying flawless intelligence systems to deliver actionable information for appropriate control decisions via a reliable communication infrastructure. While numerous sensors deployed in the grid make more data available, it is crucial that the core information content be extracted in a timely and efficient manner to truly achieve the objectives of the grid of the 21st century. It is envisioned that integrating such functionalities into the operations of the distribution grid will effectively help make the grid more efficient, reliable, robust, and smarter than before.

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Network management for smart grids

Innovative operations centers to manage future distribution networks

Tim Taylor, Marina Ohrn

Traditional power networks have been carefully managed at operations centers to ensure adequate power supplies are maintained despite peaks and troughs in demand. Each section of the grid has an operations center that conducts and coordinates various functions including system monitoring, control, crew administration and dispatch. It has been regarded conventionally as "the brain" of the power system, from which operations have been directed.

As distribution systems are gradually evolving into smart distribution systems, the operations centers that control them are evolving to take on new roles to manage such grids. The separate IT systems operating in these control centers are becoming more streamlined, communicating seamlessly to provide an integrated monitoring and management system. More advanced applications and analytical software are providing more sophisticated analyses and automated operations. The control systems of operations centers are not only helping to make the grid smarter but are also helping to improve support for decision makers responsible for operations, maintenance and planning. Such integrated operations centers are helping distribution organizations meet their goals despite ever-increasing challenges.

Transmission and distribution

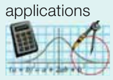
Conventional monitoring and control systems for distribution networks have in the past been relatively low-tech. Wall boards displaying the system's status were commonplace. These boards could be covered with sticky notes, push-pins, and ad-hoc changes, which may have been difficult to monitor and inflexible. Paper-based maps of the distribution circuits, which were often annotated manually and risked being out of date, were used to direct maintenance work on the system. Paper-based switch orders were used to plan, execute and track scheduled switching on the system. Outage calls were received by operators, with little information to provide to customers about the outages. Paper-based outage tickets were commonly used for tracking customer outages. Communications with field-based crews were conducted by radio. These crews had to supply their location to the operating centers, and the communication of switching, the placement of tags and other operations were made verbally.

This is not to say that distribution operations have stood still over time. As technology and business needs have changed so too have many distribution operations centers. Many Supervisory Control and Data Acquisition (SCADA) systems have been extended from the transmission system to include monitoring and control of medium-voltage (MV) feeder breakers. In some cases, SCADA has been further extended out beyond the MV feeder circuit breaker to equipment such as reclosers, switches and capacitor switches.

Environmental sustainability and ways of limiting carbon emissions have led to increased interest in smart grids.

Modern computer-based outage management systems (OMSs) utilizing connectivity models and graphical user interfaces have become more common. An OMS typically includes functions such as trouble-call handling, outage analysis and prediction, crew management, and reliability reporting. At some distribution companies, an OMS can be utilized simultaneously by hundreds of users. It integrates information about customers, system status, and resources such as crews.

1 Deficiencies in today's distribution operations centers for grid management

	Separate IT systems 	Incomplete real-time system status 	Few advanced applications 
Examples	Non-integrated systems for: ■ Customer information system ■ Geographic information system ■ Trouble calls ■ Crew management ■ Switch order management ■ AMI ■ SCADA ■ Mobile workforce management ■ Work management	Lack of: ■ Equipment loading information ■ Status of switches, voltage regulator taps, capacitor banks ■ Location of momentary faults on system ■ Status of distributed resources ■ Customer demand/load	Lack of applications for: ■ Fault location ■ Restoration switching analysis ■ Volt/var control ■ Distribution state estimation
Consequences	■ Inefficient work processes ■ Redundant and/or inaccurate data ■ Longer outage durations ■ Possible noncompliance of work processes with possible safety issues	■ Inefficient equipment utilization ■ Difficult to enable customers to connect distributed energy resources to grid ■ No understanding of automated operations on feeder	■ Longer outage durations ■ Inefficient use of crew hours ■ No chance to reduce customer demand through voltage control at peak times ■ Higher system losses ■ Increased customer complaints for voltage out of range

Status

Despite the progress that has been made, there are still fundamental issues that need to be addressed. The table provides examples and discusses the consequences of separate (non-integrated) IT systems, incomplete real-time system status and the lack of advanced applications in the operations of distribution organizations 1.

The case for change

Within the last few years, several external drivers have helped accelerate the development and expansion of applications for smart grid technology. Drivers for change include society and government, the business environment of distribution organizations and technology.

In many countries, legislation and regulatory initiatives have been targeted towards the modernization of the grid. Environmental sustainability and ways of limiting carbon emissions have led to increased interest in smart grids. The increasing costs of new power generation and transmission, both in terms of infrastructure and fuel costs, are also factors influencing technology change. Further drivers for the development and adoption of smart grid technology have been the public's interest to stabilize climate change through greater use of renewables and calls from utilities and governments for improved distributed generation and demand response. From a business perspective, however, distribution organizations are looking to smart grids to help them maintain or improve reliability, increase asset utilization, deal with aging infrastructure and help reduce the impact of knowledge loss as employees reach retirement age.

In many countries, legislation and regulatory initiatives have been targeted toward the modernization of the grid.

Technology has also been a great driver in smart grid development. Communication technology has strongly developed in the last decade. Today distribution companies have the choice between many different solutions. The communication can be based on a dedicated network owned by the distribution organization (eg, SCADA radio networks), or on third-party infrastructure (eg, global system for mobile communications, or GSM, provider networks). Depending on various factors, like required availability and bandwidth, the distribution organization can select the appropriate technology. Whatever the choice, it is certain that additional two-way communication in distribution networks will increase.

There are increasing numbers of distribution equipment with sensing, data processing, control, and communications on the feeder. Automation systems are becoming more common, with smart devices and appliances within a home network. The deployment of this technology will depend upon the development and unification of interoperability standards. The development of such standards is ubiquitous in the United States and Europe.

Automation systems are becoming more common, with smart devices and appliances within a home network.

Systems integration

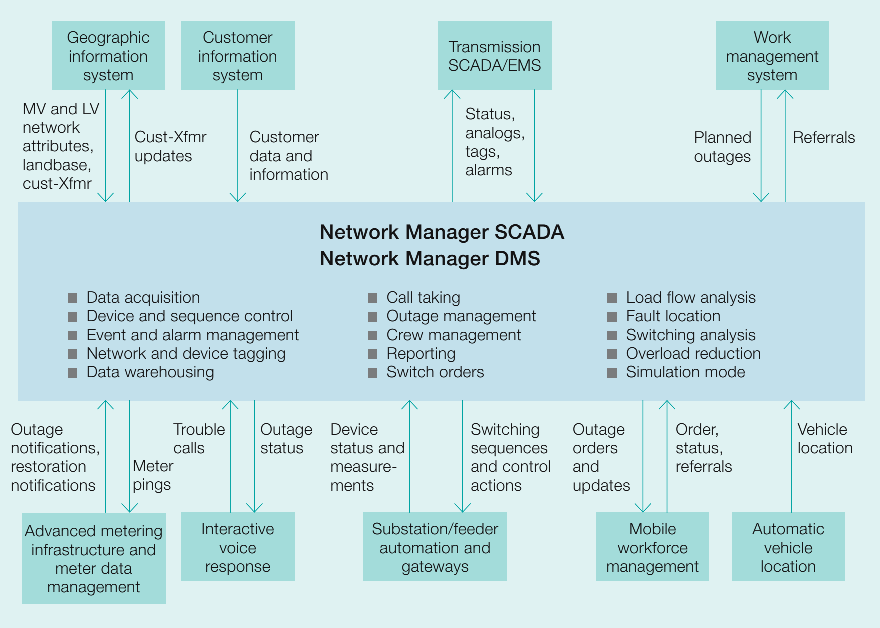
ABB is a leader in the development of smart grids around the world, and has invested time and resources to create the operations center systems that will control smart grids. Three important areas of systems integration are distribution management system (DMS) integration with SCADA, advance metering infrastructure (AMI) integration with the DMS, and the integration of data from substation gateways.

ABB has long been a leader in integrating SCADA at the distribution level with DMS applications. With the smart grid driving more distribution companies to install additional SCADA on the distribution system, ABB continues to improve its integration. Available functionality now includes the transfer of status/analog points from SCADA to the DMS; the sending of supervisory control and manual override commands from the DMS to the SCADA system; an integrated user interface running on the same PC operator console between the two systems; and integrated single sign-on for users.

The benefits of integrating SCADA with DMS include:

- Improved operations by close integration of DMS applications with distribution SCADA
- Increased operator efficiency with one system, eliminating the need to go to multiple systems with potentially different data

2 Systems integration for distribution-grid operations centers



3 Functionality and benefits of advance applications

DMS application	Functionality	Benefits
Unbalanced load flow analysis	Determination of the line currents and node voltages per phase for the entire distribution system, either online or offline in simulation mode	■ Improved system awareness ■ Higher asset utilization ■ Improved contingency planning
Load allocation and state estimation	Intelligent allocation of telemetered or historical measurements over the network to calculate estimated power flows, voltages, and limit violations based on real-time conditions	■ Improved load flow and state estimation calculations ■ Improved notification of overloaded equipment and voltage violations
Fault location	Identification of possible fault locations on system	■ Improved crew efficiencies in managing outages ■ Reduced customer average interruption duration index (CAIDI) and system average interruption duration index (SAIDI)
Restoration switching analysis	Evaluation of isolation and restoration switching schemes	■ Improved operator efficiencies during outages ■ Increased reliability
Distribution Volt/Var control	Monitoring and control of line capacitors, voltage regulators, and load tap changers (LTCs) to reduce peak load and system losses	■ Reduced customer demand at system peaks ■ Lower system losses ■ Improved voltage profiles
Line unloading	Computation and analysis of load transfer options, including overload reduction	■ Reduced thermal-mode failures ■ Longer equipment life due to reduced overloads ■ Higher asset utilization
Remote switching and restoration	Automatic feeder reconfiguration considering network operating conditions	■ Reduced CAIDI and SAIDI ■ Lower system losses

- Integrated security analysis for substation and circuit operations to check for tags in one area affecting operations in the other
- Streamlined login and authority management within one system
- Consolidated system support for DMS, OMS and distribution SCADA

Installation of AMI systems is rapidly increasing, and ABB is developing ways that distribution organizations can leverage AMI data for operational purposes. Interfaces between AMI/MDM (meter data management) and SCADA/DMS have been developed for meter status queries, outage notifications and restoration notifications. Benefits include reduced customer outage durations and more efficient use of field resources. The use of other AMI data in DMS applications, such as interval demand data and voltage violations, is being explored. This would provide additional benefits, such as improved knowledge of system loading and better voltage profiles throughout the system.

In addition, many organizations are increasing the amount of substation automation and substation gateways on their systems. This provides increased access to data in intelligent electronic devices (IEDs) that are installed in substations and distribution systems, many of which have communications capabilities. These include more intelligent recloser controls, switch controls, and voltage regulator controls. Integration of these systems with the DMS provides the benefit of decentralized local control at the substation/feeder level, while providing system optimization through the DMS at the system level. The integration of SCADA and DMS with other systems provides an integrated operations center for managing the smart grid 2.

ABB has long been a leader in integrating SCADA at the distribution level with DMS applications.

Advanced network applications

With its Network Manager™ platform, ABB is leading the distribution industry in the development of advanced applications for distribution system management. Advanced applications use the network model along with the monitoring of the network operating conditions to provide recommendations for optimal network operation. As shown in the table, advanced applications can provide solutions to many challenges that distribution organizations are facing today 3.

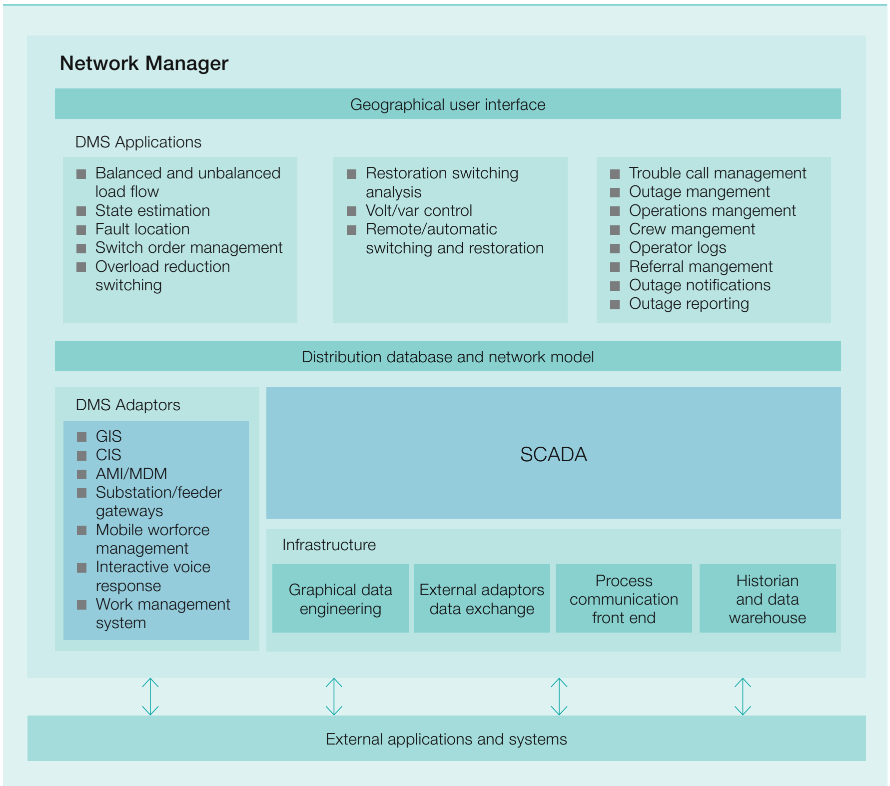
In many cases, distribution organizations choose to leave the operator in the decision loop so that the operator can oversee the system; however, as smart grids evolve, the desire to minimize human intervention will favor a closed-loop or automated approach. In the future, the degree to which the system is automated will be a business decision for each distribution organization.

The operations center

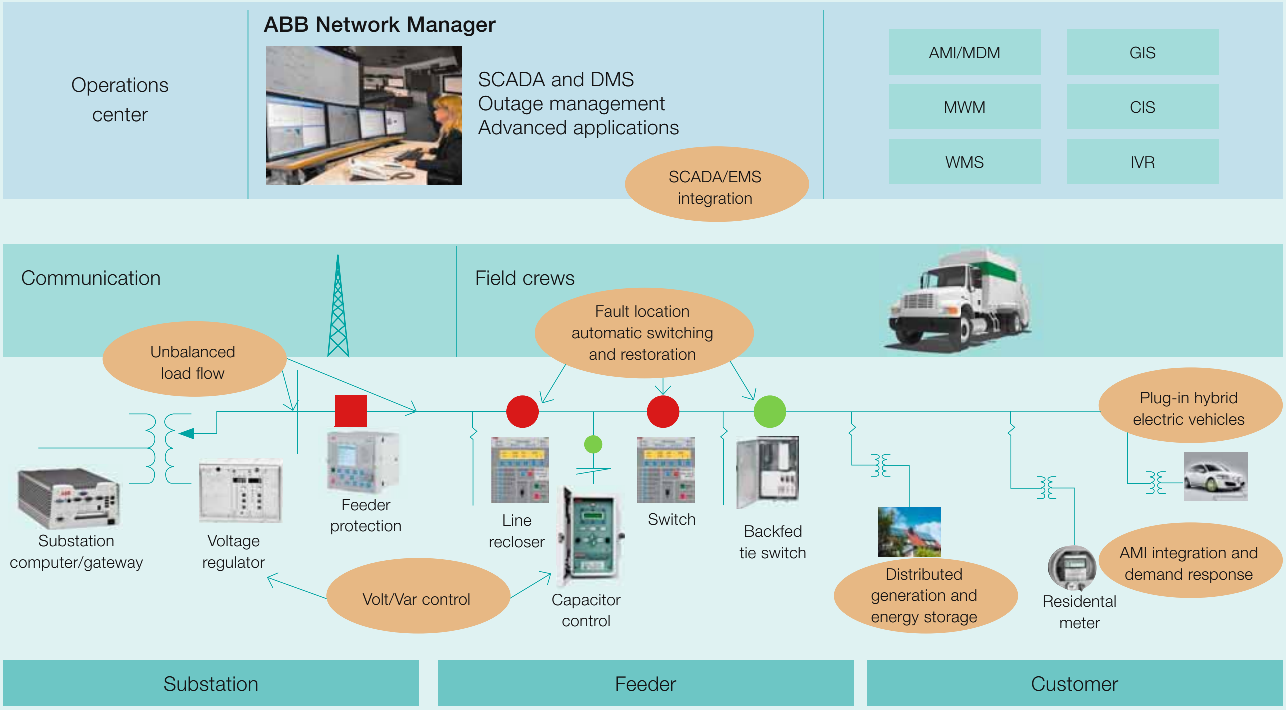
The architecture of a fully integrated distribution operations center is shown in 4. DMS applications are utilized for the optimal management of the distribution systems with respect to equipment loading, efficiency, voltage control, work management, outage management, and reliability. The DMS applications utilize the distribution database and electrical network connectivity model. The network model is initially created using a one-time data load from a geographic information system (GIS), and is periodically updated from the GIS using an incremental update process.

A key part of the integrated distribution control system is the integration of the different IT systems used in the operation of distribution systems. This includes the SCADA system as a key element of data collection and system control. The trend is for distribution companies to expand SCADA systems past the distribution substation and onto the feeders, providing improved situational awareness and control of the distribution system. Interfaces to other systems include AMI and MDM systems, and substation/feeder gateways and data concentrators. The architecture of how data is transmitted between field devices and the integrated operations center will vary among distribution organizations. There may even be several approaches within a single utility. Whatever the

4 The architecture of a fully integrated distribution operations center



5 An integrated distribution operations center overseeing the distribution grid



approach, such data transmission is critical for increased operational awareness.

Future operations center

The integrated operations center will be a key to the smart distribution grid. ABB continues to increase the functionality of operations centers to meet distribution organizations' technical and business requirements. A vision of the smart distribution grid utilizing an integrated distribution operations center is shown in 5.

In a general sense, the operation of distribution systems will become more complex. Additional amounts of distributed generation and energy storage will impact the magnitudes and directions of power flows on the system and may vary over time. Demand response, either controlled by the electricity provider or the consumer, will also impact power flows and voltage profiles. In addition, there is already an increasing trend to place additional intelligence in devices on the distribution system, such as intelligent electronic devices (IEDs), substation computers and gateways, sensors, and advanced meters. Some of these devices will result in additional local control actions, further increasing the complexity of distribution systems' operation.

Even in the presence of increasing amounts of decentralized intelligence and control, the integrated operations center will be a centralized way of overseeing and coordinating the entire system. It will not be practical or even desirable to transmit all data and information to centralized systems in the integrated control system. Instead, to ensure the optimal operation of the system, the systems in the integrated distribution operations center will only collect and act upon the particular data and information that is passed to it.

Meeting the challenge

Smart distribution grids will require innovative operations centers for effective system management. ABB has been continuously working to define and develop integrated operations centers for smart distribution grids, including advanced integration of existing systems and the development of new applications. Smart grid operations will provide a comprehensive view of the distribution system, including system status and monitoring, control, outage response, planned work, optimal equipment loading, improved control over distributed generation, energy storage and demand response resources. The integrated distribution operations center will help distribution companies in their mission to meet the goals of customers, owners, employees and society.

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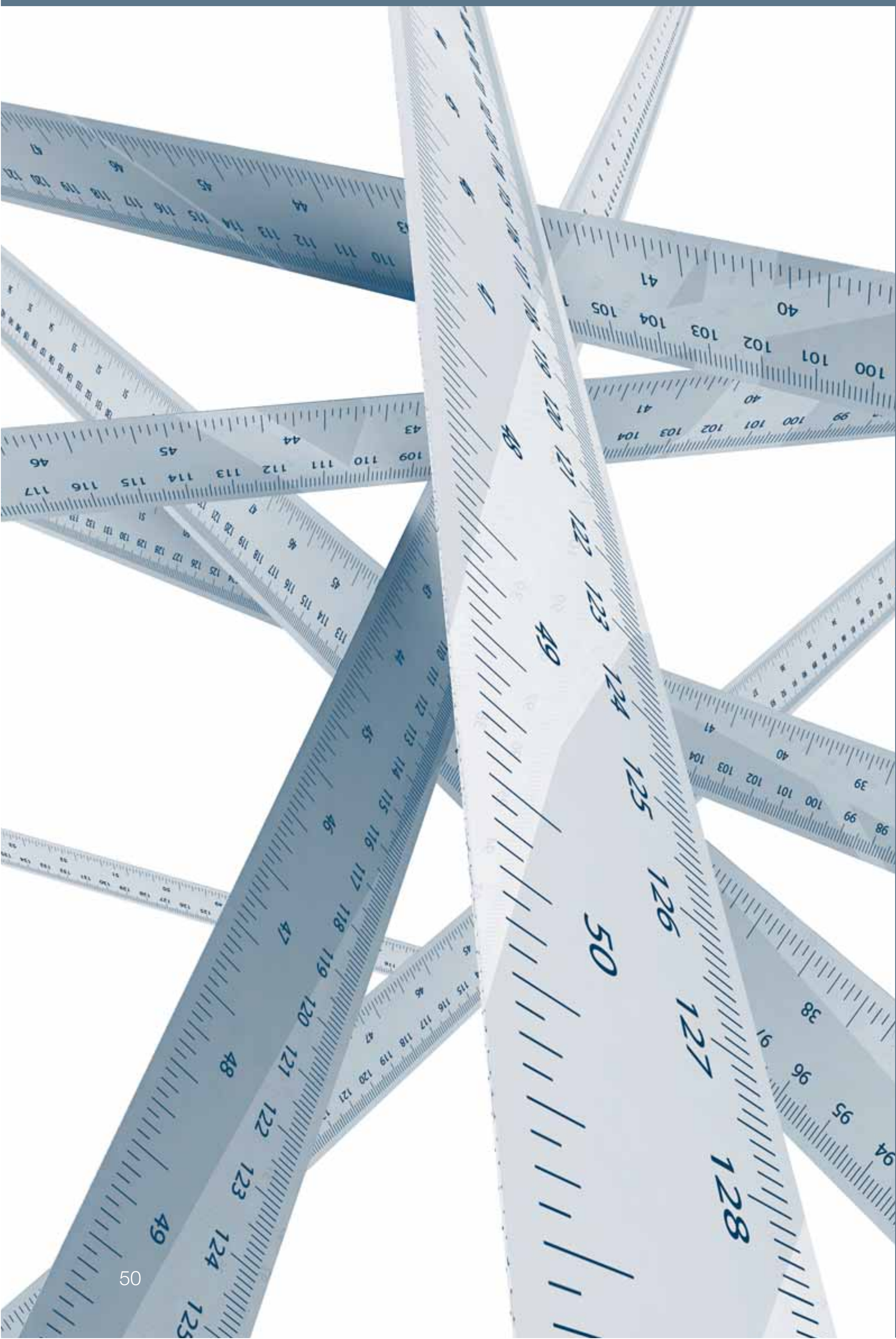
In harmony

Defining global energy-efficiency standards

Janusz Maruszczyk, Michel Lhenry, Mikko Helinko, Zbigniew Korendo



Energy efficiency has become an essential attribute of today's industrial products and systems. But the multitude of different standards in this area makes the direct comparison of energy-efficiency performance indicators enormously difficult, if not impossible. The globalization of markets has resulted in the need to compare the energy efficiency of devices in the same product group, regardless of where a specific device was produced. The harmonization of standards and underlying legislation is a prerequisite for successful proliferation of energy-efficient technologies.

Standardization initiatives have resulted in the harmonization of energy-efficiency requirements, testing methods and certification schemes in a number of areas, including electric motors. Today, all major organizations that develop standards, as well as intergovernmental bodies, are working on defining common frameworks for the comparable qualification of products and systems in terms of their energy use. This is just the beginning of a very important undertaking.

From a technical and legal perspective, the electrotechnical market is very complex. Every electrical device must comply with various requirements connected to its application, safety and compatibility with other devices. Those requirements may be included in national, regional or industrial regulations, procedures or standards. Often there are additional indirect requirements.

Standards may address the energy efficiency of a specific device in different ways. The typical process of determining the efficiency of a device is to measure the value of energy losses in accordance with the rules defined in a standard. The results (energy losses or calculated energy efficiency) are matched against efficiency indexes (normative loss or efficiency values) to determine if the device meets the minimum energy-efficiency performance standards (MEPS) or some other regulations. If the device meets the MEPS requirements of a given country, it can be put on the market. If it meets the voluntary labeling scheme criteria, it can also be labeled and recognized as an energy-efficient product.

Standards define what energy efficiency is, determine the procedure for testing and measuring energy usage, and integrate the requirements of MEPS or voluntary labeling schemes. Problems arise when those standards are not harmonized across countries or industries. A nice example of the successful harmonization of standards can be found in the electrical motor industry.

Harmonization in motors

It is estimated that 40 percent of the world's electricity is used by electric motors in a variety of applications. The improvement of motor efficiency depends on the total reduction of all types of energy losses that exist in motors:

- Stator winding losses (P_s)
- Iron losses (P_{fe})
- Rotor losses (P_r)
- Friction and windage losses (P_{fw})
- Additional load losses (P_{LL})

For many years there were two main standards used around the world to determine these losses:

- IEC 60034-2
- IEEE 112 method B (or IEEE 112-B)

IEC 60034-2 was used mainly in Europe, India and China, and previously in Australia and New Zealand. The method defined in IEEE 112-B was used in North America and countries with a 60 Hz power supply. Around 2000, a method similar to IEEE 112-B was introduced in Australia and New Zealand, but IEC 60034-2 may still be operational in those countries. An equivalent standard (CSA C390) was adopted in Canada.

Standards define what energy efficiency is, determine the procedure for testing and measuring energy usage, and integrate the requirements of MEPS or voluntary labeling schemes.

IEEE 112-B eliminated the temperature problems existing with IEC 60034-2 for calculating the stator winding and rotor losses at fixed temperatures. Additionally a test procedure was established to determine additional load losses to avoid the fixed allowance existing in IEC 60034-2. Consequently two dominant efficiency determination methods emerged for polyphase electrical motor efficiency: IEC and IEEE 112-B 1.

In the European Union, the determination of efficiency was performed in accordance with the testing method described in IEC 60034-2. The voluntary agreement of the European Committee of Manufacturers of Electrical Machines and Power Electronics (CEMEP) defined three possible efficiency classes for motors:

EFF3 Low-efficiency motors
EFF2 Improved-efficiency motors
EFF1 High-efficiency motors

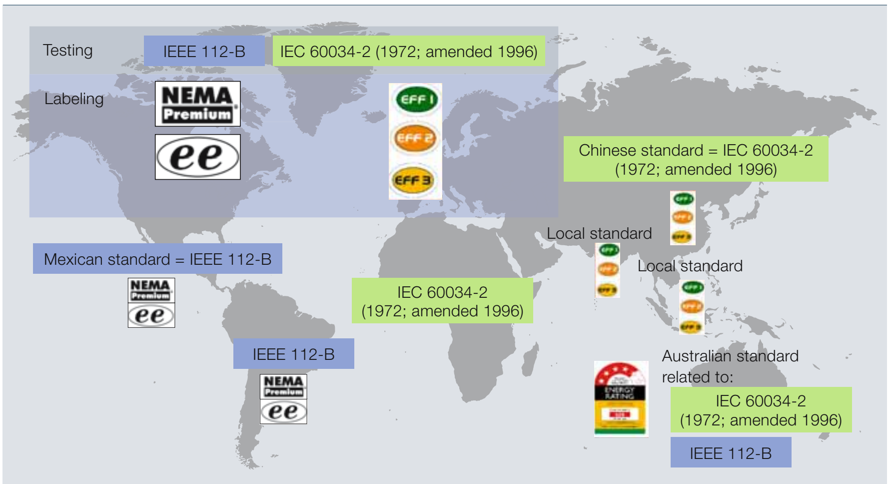
The agreement also stipulated that the manufacturers should mark the efficiency level on the product nameplates and a sample data table to help users select and identify the most suitable motor.

In the United States, the determination of efficiency was based on the IEEE-112 standard. The testing method, IEEE 112-B, required direct measurements of all losses under a network frequency of 50 or 60 Hz. The MEPS for all motors produced or used in the United States were established in the Energy Policy Act (EPAct 1992). Later NEMA proposed a voluntary certification program, NEMA Premium, which was based on IEEE 112-B. For both mandatory and voluntary requirements, the measurement results were later matched against specific efficiency indexes, which were defined in the NEMA MG1 standard.

In addition, the United States uses the industrial standard IEEE 841 in the chemical, petroleum and metallurgy industries for heavy-load motors with long operation times.

The solutions in other countries were thus an adaptation of the EU or US approaches – they were either harmo-

1 Motor efficiency standards and labels: historical status



Efficiency and standards

nized with or similar to IEC 60034-2 or IEEE 112-B.

Brazil, for example, has a test method based on IEEE 112-B, but the existing MEPS is different from that which is used in the United States. In India, efficiency classes were harmonized with CEMEP, but the test method is based on the local standard rather than on the IEC standard. China adopted the MEPS policy; its minimum energy-efficiency requirements and energy-efficiency grades for small and medium three-phase asynchronous motors are described in China's GB 18613-2006 standard. For testing purposes, however, a local GB/T 1032 standard – equivalent to IEC 60034-2 – is used. Additionally in China there are a few groups of de facto standards (eg, the so-called Y-series motors). These types of motors, although not described in the predominating standards, are widely recognized on the Chinese market and are regarded as the reference.

Different testing methods and labeling schemes led to problems with the comparability of motor efficiency. Additionally, the nomenclature used in various economies was a problem as well. The phrase "high-efficiency motor" might have a different meaning in different markets or countries. What was considered a high-efficiency motor in one country might hardly have met the minimum efficiency levels of a country with more advanced technologies. Together, these elements were blocking the global promotion of energy-efficient motors.

Working toward homogenization

Efforts were thus made to move toward unity and away from the redundancy of the existing standardization practices. Based on a new work item proposal issued by the German national committee DKE K311, a working group (WG 31) was established in 2006 by the IEC TC 2 (the rotating electrical machines technical committee) and was assigned the task to define energy-efficiency classes for three-phase industrial motors.

Another contributor to this harmonization process was the private initiative known as Standards for Energy Efficiency of Electric Motor Systems (SEEEM), created in 2006, whose recommendations were also taken into consideration by WG 31.

What was considered a high-efficiency motor in one country might hardly have met the minimum efficiency levels of a country with more advanced technologies.

The first meeting of WG 31 took place in October 2006 in Frankfurt, Germany. By the second meeting in May 2007 in Washington, DC, it was clear that the existence of a classification standard alone would not solve all the problems – the methods for energy-efficient operation of electric motors and applications should be described as well. In May 2007 a proposal to create an energy-efficiency guide was presented at the general IEC TC 2 meeting in Milan, Italy, where the project was confirmed and launched under the name IEC TS 60034-31.

Also, IEC TC 2 began revising the IEC 60034-2 standard, which had been around for many decades. The revision was initiated in 1996 when a European Commission mandate (M244) was given to CENELEC (European Committee for Electrotechnical Standardization), who then passed the task of developing a new testing standard to the IEC. The intention was to prepare a new IEC standard similar to IEEE 112-B. At the first WG 2 meeting of IEC SC2G in September 1997 in Frankfurt, the IEEE 112-B test method was presented by a member of IEC working group but this first proposal was not accepted. (Incidentally, working group 2 would later become WG 28 of IEC TC 2.) After many years of discussion, the test method was put into IEC 61972. Later, the method was included in the new edition of IEC 60034-2 **2**. Consequently, IEC 61972 has been withdrawn.

Further activities undertaken by the IEC technical committee 2, rotating machinery (WG 28 and WG 31), resulted in the following standards:

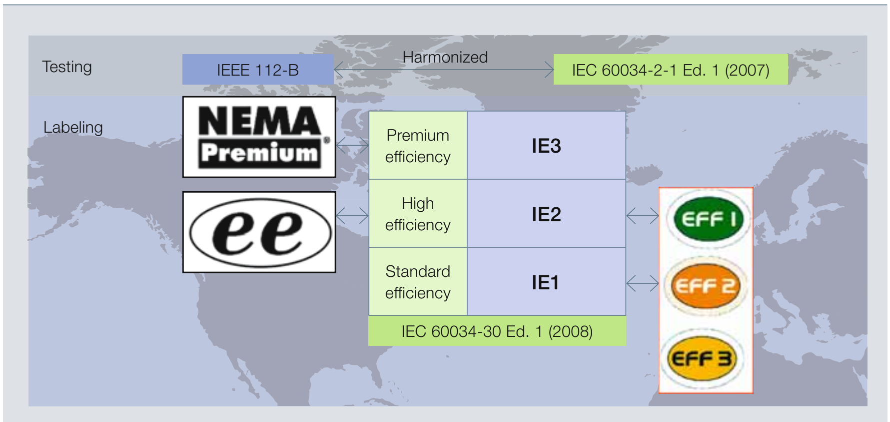
IEC 60034-2-1 (2007) Includes the efficiency testing methods (harmonized with IEEE 112-B; however, small differences still exist).

IEC 60034-30 (2008) Defines new efficiency classes IE1, IE2 and IE3, which are harmonized at 60 Hz with Brazilian regulations (IE1) and are harmonized with current US regulations for enclosed motors (EPAct for IE2 and NEMA Premium for IE3), eg, IP44, IP55, and are based on EU-CEMEP (EFF1, EFF2) for IE2 and IE1. The IE3 class introduced at 50 Hz is derived from IE2 with about 15 percent lower losses. This standard excludes motors that were designed in accordance with IEC 60034-25 (ie, motors specifically designed for converter supply), and motors that are the integral part of appliances (eg, pumps or fans).

In addition, the following standards are currently under development by the IEC:

IEC TS 60034-31 Guide for the selection and application of energy-effi-

2 Efficiency classes around the world (2009)



cient motors, including variable-speed applications (planned publication in April 2010; the second draft became available in April 2009).

IEC 60034-2-3 Testing standard for converter-fed AC machines (planned publication in July 2011).

Meanwhile, the US Department of Energy has mandated that, beginning December 19, 2010, NEMA Premium will become the minimum energy-efficiency performance standard for motors in the United States. In order to obtain the certification, the producer must test its products in an accredited laboratory. The other rules (ie, IEEE 112-B as the testing standard and NEMA MG1 as the efficiency-class standard) remain unchanged.

In the EU countries the situation is different – it is the producer who is held responsible for compliance with standards. The third-party certification is not mandatory; however, government agencies will perform occasional market audits. Should a device not meet the required (and declared) efficiency levels, the producer will be obliged to remove it from the market at his own cost.

The Ecodesign Regulatory Committee, composed of representatives of the Member States of the EU, voted positively for a new regulation, Ecodesign Requirements on Electric Motors, on the basis of a proposal from the European Commission. The new regulation states the energy-efficiency class for asynchronous motors with an output power between 0.75 kW and 375 kW. The IE2 efficiency class defined in EN/IEC 60034-30 will become mandatory starting June 16, 2011, the IE3 class for motors with a nominal power (P_N) output from 7.5 to 375 kW starting in 2015, and for motors with P_N from 0.75 to 375 kW in 2017. An IE2-class motor may be used in place of an IE3 motor if it is supplied through a converter drive. This regulation was adopted by the European Commission on July 22, 2009. The scope of the regulation differs slightly from the IEC 60034-30 standard (eg, motors for converter operations are included). 3 shows the anticipated implementation roadmap of the different IE efficiency levels as defined by IEC 60034-30, as well as the minimum energy-efficiency standards in various countries.

3 Implementation roadmap of the different IE efficiency levels as defined by IEC 60034-30

Efficiency level	Efficiency class IEC 60034-30	Uncertainty as per testing standard IEC 60034-2-1 (2007)	Countries having performance standard regulations
Premium efficiency	IE3	Low uncertainty	USA (2011) Europe (2015/2017*)
High efficiency	IE2	Low uncertainty	USA Canada Mexico Australia New Zealand Brazil (2009) China (2011) Europe (2011*) Switzerland (expected 2012)
Standard efficiency	IE1	Medium uncertainty	China Brazil Costa Rica Israel Taiwan Switzerland (expected 2010)

No date indicates that specific MEPS regulations are already active. IEC 60034-2-1 includes several test methods associated with different uncertainties. For IE1, test methods associated with low and medium uncertainty are acceptable; for IE2 and IE3, low uncertainty is required.

*) Schedule for efficiency-level implementation in the EU:
- After June 16, 2011 all motors from 0.75 kW to 375 kW must meet the IE2 efficiency class.
- Effective January 1, 2015 motors with a nominal power (P_N) of 7.5 to 375 kW cannot be less efficient than the IE3 efficiency level, or must meet the IE2 class, and must be equipped with a variable-speed drive (VSD).
- As of January 1, 2017 motors with a P_N of 0.75 to 375 kW cannot be less efficient than the IE3 class, or must meet the IE2 requirements and be equipped with a VSD.

Factbox 1 IEC conditions precedent to standardization in the area of energy efficiency

- Distinct, reasonable and coherent definition of “efficiency”
- Definition of test and measuring methods for the evaluation and rating of efficiency
- Definition of efficiency levels (classes) for standard and commodity products
- To start standardization only in those areas where a significant savings potential exists; priority on “high potentials”
- Mandatory limiting values shall be prescribed by the authorities

Source: IEC Workshop, Sao Paulo, Nov. 2008

Working group 31 of the IEC TC 2 is currently developing a new IEC TS 60034-31. A draft document was issued in which the definitions of super premium or IE4 classes were proposed. The IE4 energy-efficiency class is not limited to three-phase cage-induction motors like the IE1, IE2 and IE3 classes of EN/IEC 60034-30. Instead, IE4 is intended for use with all types of electrical motors, particularly with converter-fed machines (both cage-induction and other types, such as permanent-magnet synchronous motors). Currently, there are no motors on the market that fit this energy-efficiency class level. This nicely illustrates the fact that standardization may be determining the direction of technology and product development.

A case for standardization

Standards and labels are present in all areas of energy-efficiency policy support, particularly for specific products (like motors) or applications. Standards:
- Define what efficiency is (IEC 60034-2-1).
- Formulate testing procedures to determine efficiency (IEC 60034-2-1).
- Establish minimum required efficiency indexes and efficiency requirements for various voluntary efficiency labels and certificates (EN/IEC 60034-30, NEMA MG1).
- Define the maintenance conditions that should be met to achieve high efficiency (ANSI/EASA AR100, EASA/AEMT).
- Describe specific industrial or sector rules and requirements (IEEE 841).
- Push the direction of technology and product development toward more energy-efficiency-oriented solutions (IE4, IEC TS 60034-31).

The International Energy Agency (IEA) launched the 4E implementing agreement Efficient Electrical End-Use Equipment in March 2008. A part of

Efficiency and standards

Factbox 2 Acronyms

AFNOR	Association Française de Normalisation (French national organization for standardization)
CEMEP	Comité Européen de Constructeurs de Machines Electriques et d'Electronique de Puissance (European Committee of Manufacturers of Electrical Machines and Power Electronics)
CEN	Comité Européen de Normalisation (European Committee for Standardization)
CENELEC	Comité Européen de Normalisation Electrotechnique (European Committee for Electrotechnical Standardization)
EMSA	Electric Motor Systems Annex
EPAct	Energy Policy Act
IEA	International Energy Agency
IEC	International Electrotechnical Commission
ISO	International Organization for Standardization
MEPS	Minimum energy-efficiency performance standards (also referred to as minimum energy performance standards or minimum efficiency performance standards)
NEMA	National Electrical Manufacturers Association
SEEEM	Standards for Energy Efficiency of Electric Motor Systems

Factbox 3 ABB motors and the new efficiency standards and labels

- ABB ensures that its products fully comply with the new requirements.
- ABB supplies a full range of motors in the IE2 class, as well as premium efficiency motors in the IE3 class.
- Motors' ranges, including flameproof Ex d, dust ignition proof Ex tD and non-sparking Ex nA from 0.75 to 375 kW, are labeled according to IEC/EN 60034-30.
- The efficiency values are determined according to standard EN/IEC 60034-2-1 with the low uncertainty method defined in this standard.

4E, the Electric Motor Systems Annex (EMSA) is focused on motor-systems efficiency. It addresses energy efficiency not only from a product perspective, but also with regards to the motor as a part of a broader system that has its own energy-efficiency potential. EMSA is building a Global Motor Systems Network to provide information on new developments in standards and technology. The system approach, while potentially offering the biggest benefits, is very difficult to standardize, which is why past standardization efforts have mainly dealt with efficiency standards for devices.

Focus on energy efficiency

In recent years, the issue of electrical energy efficiency has been recognized by the International Electrotechnical Commission as one of the key priority areas. The IEC standardization management board (IEC-SMB) has established a strategic group (SG 1) – energy efficiency and renewable resources – that cooperates closely with its sister counterpart in ISO - ISO/TMB/SAG EE 1, strategic advisory group on energy efficiency. The IEC-SMB SG 1 has defined a set of recommendations regarding energy-efficiency-related issues for IEC technical committees Factbox 1. As such, after IEC-SMB approval, these considerations determine the direction of future IEC works in this area.

One of the main requirements identified by SG 1 is to establish common terminology and definitions concerning energy efficiency. Presently there are a number of initiatives and activities in both standards-setting and legislation – eg, ISO/CSC/STRAT, CEN/CENELEC sector forum energy management (SFEM), existing IEC standards and legislation – that refer to basic terms (eg, energy efficiency, energy performance) in different ways. As a result, their interpretation may differ in various contexts and applications. Upon the recommendation of SG 1, ISO has begun developing a new standard that will fix the basic terminology for all organizations dealing with energy efficiency. The French national organization for standardization (AFNOR) will coordinate this development, which is estimated to be completed in about three years.

The SG 1 recommendations extend further to focusing standardization on those products and processes where energy-efficiency gains are expected to be the most significant; that is, products and devices operated in large volumes. This applies to, for example, lamps and lighting, rotating machines, heating and cooling applications, power generation and transmission, power transformers and consumer electronics.

Another priority area distinguished by SG 1 is the development of: standards and best-practice guidelines concerning optimal matching of a given product to actual application; guidelines for systems design with consideration for energy-efficiency criteria, automation of complex systems and plants (eg, power plants, electrical trains); and guidelines for power losses in distribution networks. SG 1 also recommends more focus on the standardization of electrical storage systems, especially in the context of distributed energy generation involving renewable sources.

This approach breaks away from the traditional focus on isolated devices, and rather takes into consideration their operation in the context of the larger system and processes for which they are used. Such system-level energy efficiency ought to be considered already at the design stage, taking into account application context, lifetime maintenance and interaction with other system components.

> Electrical energy efficiency has been recognized by the International Electrotechnical Commission as one of the key priority areas.

Like the IEC, the International Organization for Standardization pays significant attention to various aspects of energy efficiency. Apart from the joint development of a basic terminology standard for the energy-efficiency domain, ISO technical committees work on standardizing methods of calculating, comparing and labeling with respect to energy performance, consumption and efficiency of various devices, means of transport and buildings. In this area, development of the standard ISO 13602 (by TC 203, technical energy systems), which includes principles for comparable characterizations of different sources of energy, is ongoing.

Another novel standardization area is energy-management systems. It is addressed notably in the upcoming standard ISO 50001, the final version of which is expected around 2010 (a draft version of the document has already been created). It is anticipated that this standard will have an impact on energy-related issues similar to that of ISO 9001 (on quality management) and ISO 14001 (on environmental management). ISO 50001 does not introduce required efficiency levels, but rather postulates continual improvement of overall energy efficiency of a plant or factory. This new standard may encourage companies to develop comprehensive, system-level approaches to energy-efficiency management, including efficiency measurement, monitoring and process-control optimization, to name but a few. A typical example of such a system is building systems (said to be accountable for about 30 percent of overall energy use). The new ISO standard takes a holistic perspective of intelligent buildings – from design requirements and the use of alternative energy sources to control and management systems. Determining the energy efficiency of the whole system presents substantially different challenges and requires methodologies beyond just benchmarking an isolated motor under laboratory conditions. Standards for assessing system-level energy-efficiency are an important element of enforcing energy-saving policies.

Standardization may be determining the direction of technology and product development.

Facilitating change

In line with the IEA's sentiments regarding energy efficiency, international standards in this area are playing a critical role as a change enabler because they include terminology, test methods, classifications and management practices, thereby building a common implementation framework. Additionally they formalize the state-of-the-art knowledge based on the consensus of experts with a broad range of technological, industrial and economic backgrounds from all over the world.

From the perspective of the World Energy Council and the IEA, standards are one of most important tools for enabling the realization of global strategies in practice. Standards facilitate the international cooperation between governments and industrial players. This is especially important as most solutions (including renewable energies) must be implemented on a mass scale in order to achieve the desired outcomes.

In the case of most electrical devices, the harmonization of local standards with international standards leads to:

- Minimization of testing costs, especially for the organizations that produce electrical devices for global markets
- Easier comparability of efficiency and energy consumption for the same devices in various regions and economic systems
- Facilitation of the production of higher-efficiency devices
- Facilitation and enabling of knowledge transfer, resulting in standards implementation in legislation

Standards do not just define efficiency and provide the methods to assess it. Standards also describe the broader perspective – how to manage the energy in a system and how to monitor, identify and verify the energy savings resulting from specific actions taken. Such an approach is part of a wide-ranging vision of energy-efficient markets where efficiency and energy savings are a service that can be purchased and sold in a same way as electricity or gas.

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Further reading
http://www.iso.org/iso/hot_topics/hot_topics_energy.htm
http://www.standardsinfo.net/info/livelink/fetch/2000/148478/13547330/outcome.html
http://www.iea.org/Textbase/work/2009/standards/Thies.pdf
http://www.iea.org/Textbase/Papers/2008/cd_energy_efficiency_policy/7-Energy%20utilities/7-Standards.pdf
http://www.motorsummit.ch/
http://www.seeem.org/news.php
http://www.nema.org/gov/energy/efficiency/premium/
http://www.motorsystems.org/

OPC Unified Architecture

The future standard for communication and information modeling in automation

Wolfgang Mahnke, Stefan-Helmut Leitner

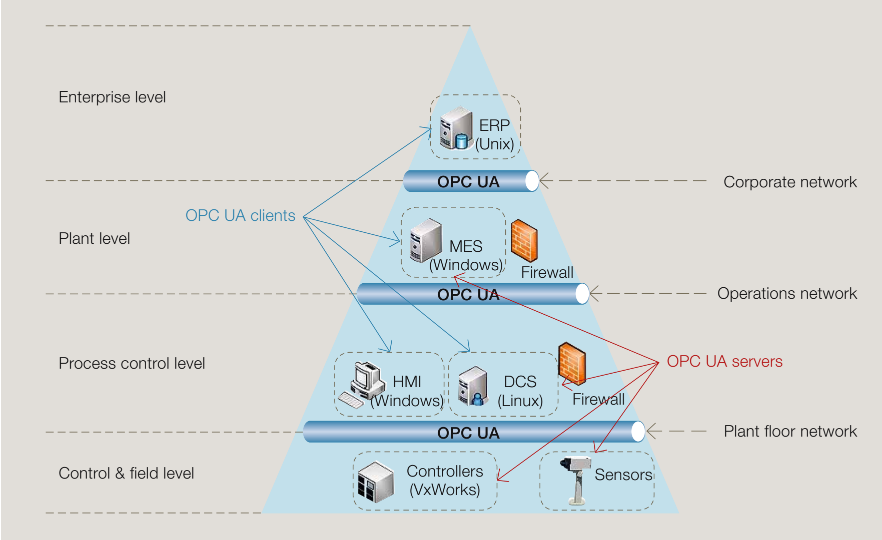
OPC Unified Architecture (OPC UA) is the new standard specification for interconnectivity in state-of-the-art industrial automation technology, enabling rich information modeling capabilities, replacing existing OPC specifications. OPC UA provides a framework for interoperability to be used over the next 10 years and beyond (published also as IEC 62541).

ABB played a major role in creating OPC UA and has ensured the new standard meets process automation community requirements. After several years of work, a major segment of the specification was released in February 2009, and the first ABB product supporting OPC UA is already on the market.

OPC is a set of industrial standards for systems interconnectivity, providing a common interface for communications between different products from different vendors Factbox 1. There are over 22,000 products supplied by over 3,200 vendors. Process control systems must be able to communicate with all these products, accessing data or providing data access via a common communications platform. Classic OPC provides standard specifications for data access (DA), historical data access (HDA), and alarms and events (A&E). These OPC specifications are widely accepted by the automation industry. Classic OPC is based on aging Microsoft-COM/DCOM-technology,[1] which has led to the development of new OPC Foundation specifications known as OPC UA (Unified Architecture). These specifications have been developed by more than 30 automation vendors, during a time period of five years. The main goal of OPC UA is to keep all the functionality of Classic OPC, while switching from Microsoft-COM/DCOM-technology to state-of-the-art Web services technology. By using web service technology OPC UA becomes platform-independent and can thus be applied in scenarios where Classic OPC is not used today. OPC UA can be seamlessly integrated into Manufacturing Execution Systems[2] (MES) and Enterprise Resource Planning[3] (ERP) systems, running not only on Unix/Linux systems using Java, but also on controllers and intelligent devices having specific real-time capable operation systems. Of course, compatibility with earlier OPC specifications was a requirement for OPC UA. It does not, therefore, preclude its use in Windows-based environments where Classic OPC already operates today – suiting Microsoft's Windows Communication Foundation[4], which can also communicate using Web services 1.

OPC UA has to fulfill and improve the non functional requirements of Classic OPC providing, for example, robust, reliable, high-performance communication suitable for automation. Learning from OPC XML-DA[5] (the first attempt made by the OPC Foundation to provide XML-based web services), OPC UA was designed to support binary encoding for high-performing data exchange. To provide reliable

1 OPC UA can be used for applications within the automation pyramid.



Factbox 1 OPC

OPC (OLE* for process control) was developed in 1996 by the automation industry as a standard specification that would allow the communication of real-time plant data between control devices produced by different manufacturers. The OPC Foundation was created to maintain the standard and has since overseen the introduction of a series of standard specifications (such as OPC data access). Today the OPC Foundation states that OPC UA is no longer an acronym for OLE for process control, but OPC UA is an acronym for OPen Connectivity Unified Architecture).

*) Object Linking and Embedding (OLE) allows the visual display of data from other programs that the host program is not normally able to generate itself (eg, "embedding" a pie chart in a text document). The data in the file used to produce the embedded chart can change, "linking" the data so that the chart is updated within the embedded document.

Factbox 2 Meta model and information models

A meta model is a model to describe models. The meta model of an SQL (Structured Query Language) database defines the concept of a table, in an object-oriented programming language the concepts of a class and objects, and in IEC 61131-3 languages the concept of tasks, function blocks, programs, etc. In OPC UA the meta model defines the concepts of objects, their types, variables, data types, etc.

An information model is a model based on a meta model defining a specific semantic (meaning). In case of OPC UA this is mainly done by defining specific types of objects and variables, but also by defining specific objects and variables having a specific semantic (eg, entry points into the address space of a server). For example, based on the OPC UA meta model an information model for analyzer devices is defined by specifying specific types of analyzers. An OPC UA server can use this type of information to represent its data coming from an analyzer device.

Footnotes

1) Component Object Model (COM) was introduced by Microsoft in 1993 to allow component software to communicate between different applications. Distributed Component Object Model (DCOM) was also introduced by Microsoft allowing software components to communicate even when distributed across a network.

2) Manufacturing Execution Systems (MES) manage and monitor work in progress on the factory floor.

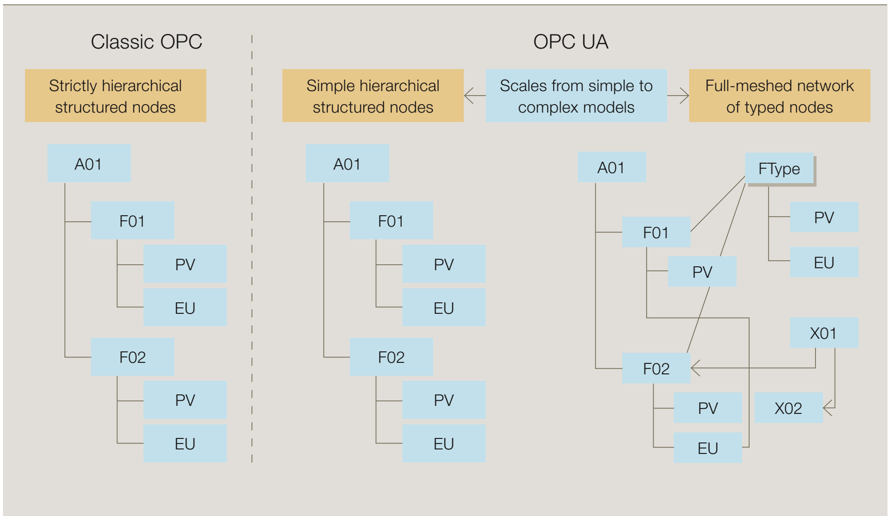
3) Enterprise resource planning (ERP) is a company-wide computer software system used to manage and coordinate all the resources, information, and functions of a business from shared data bases.

4) Windows Communication Foundation (WCF) is a programming framework used to build applications that intercommunicate.

5) OPC XML-DA builds on the existing OPC DA standard to deliver multi-vendor interoperability and connectivity to factory floor information via the Internet.

Efficiency and standards

2 Examples of OPC versus OPC UA models



communication OPC UA has built-in mechanisms able to handle problems, such as lost messages. OPC UA has built-in security, a requirement that has become more and more important in environments where factory floor data must be accessed from the office network.

OPC UA can, in the long-term, drastically reduce engineering costs when integrating systems that use products from different vendors.

OPC UA brings together the different specifications of Classic OPC providing a single entry point into a system offering current data access, alarms and events, together with the history of both. In contrast to Classic OPC, OPC UA provides a single small set of generic services access to all information.

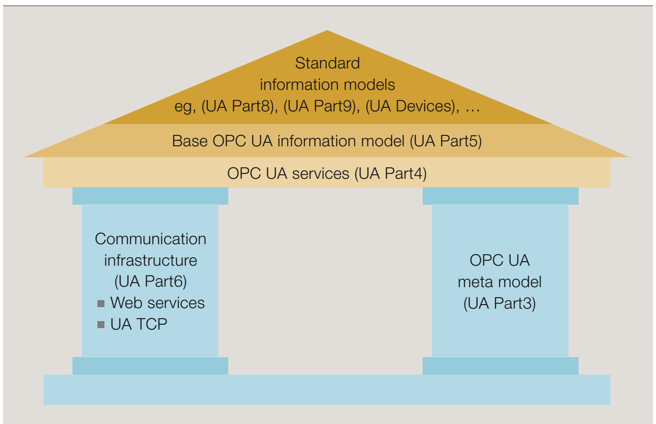
Whereas Classic OPC has a very simple meta model Factbox 2 providing tags in a simple hierarchy, OPC UA provides a rich information model using object-oriented techniques 2. It is not only possible to provide a measured value and its engineering unit using OPC UA, but also to identify the specific type of temperature sensor used to obtain that measurement. This information is helpful in typical scenarios of Classic OPC, because the same graphics, ie, software component and configuration, displayed on an operator workstation can be used for each device of the same type, operating throughout the system. In addition, this information can also be utilized in a broader area of applications, like MES and ERP systems, helping to integrate data without the need to exchange tag lists that provide the semantics of the tags. OPC UA provides the flexibility to define and use rich information models, but does not require their use. An OPC UA server can still expose a simple information model, like OPC DA servers do today, but it can also provide much more information.

A major advantage of using OPC UA compared with Classic OPC, is that it enables information modeling and facilitates many additional operations. OPC UA defines a simple set of base types that can be extended by information models (either application and vendor-specific models, or standardized models). The idea is that OPC UA specifies how data is exchanged, while standard information models specify what information is exchanged.

Intensive interest in information modeling has already created the impetus to standardize information models based on OPC UA. Common field devices could use a standardized information model to enable true plug-and-play multivendor interoperability [1]. This model was originally defined by the Field Device Integration (FDI) initiative and has already been refined by the Analyzer Devices Integration (ADI) group [2], defining specific analyzer devices. A working group, founded in October 2008 by PLCopen,[6] focuses on an OPC UA information model for IEC 61131-3 languages. The use of standard information models raises interoperability to a new level, not only allowing interoperable data exchange, but also making the model interoperable. This can, in the long-term, drastically reduce engineering costs when integrating systems that use products from different vendors.

OPC UA scales very well in several directions. It allows OPC UA applications to run on embedded devices with very limited hardware resources, as well as on very powerful machines like mainframes. Typically, servers running in such different environments will not provide the same information. The server on the embedded device is unlikely to provide a long history of the data and will only support a few clients, whereas other servers may provide several years worth of history and support thousands of clients. Information modeling aspects of OPC UA are also

3 Pillars of OPC UA



Footnote

[6] PLCopen is a vendor- and product-independent worldwide association. Its mission is to be the leading association resolving topics related to control programming to support the use of international standards in this field.

scalable. A server can provide anything from a very simple model, similar to Classic OPC, to highly sophisticated models providing highly sophisticated meta data on the given data. A client can just ignore this additional information and provide a simple view of the data or make use of the meta data provided by the server.

OPC UA defines two main pillars supporting interoperability: the communication infrastructure and the OPC UA meta model 3. The communication infrastructure defines how information is exchanged and the meta model defines what information is exchanged.

Independent of the communication infrastructure, OPC UA defines a set of abstract services [3] that can run on different communication infrastructures and use the meta model [4] as the basis for defining appropriate parameters for the services. The base OPC UA Information Model [5] provides base types and entry points to the server's address space. On top of the base information model, vendor-specific or standard information models can be built. OPC UA already defines several standard information models for data access [6], alarms and conditions [7], programs [8], historical data [9], and aggregate functions [10]. It also provides mechanisms to support multiple information models on one server. Data about the information models can be read by the services, so that clients knowing only the services, are capable of accessing all the information. Of course, clients knowing specific information models can be optimized by making use of that knowledge.

OPC UA is not directly compatible with Classic OPC, because it uses a different technology for data communication. To fulfill this requirement, however, the OPC Foundation not only provides software infrastructure for OPC UA communication (stacks[7] in ANSI C,[8] .NET[9] and Java), but also wrappers and proxies that either wrap existing servers to OPC UA clients or provide a proxy server[10] for Classic OPC clients to access OPC UA servers.

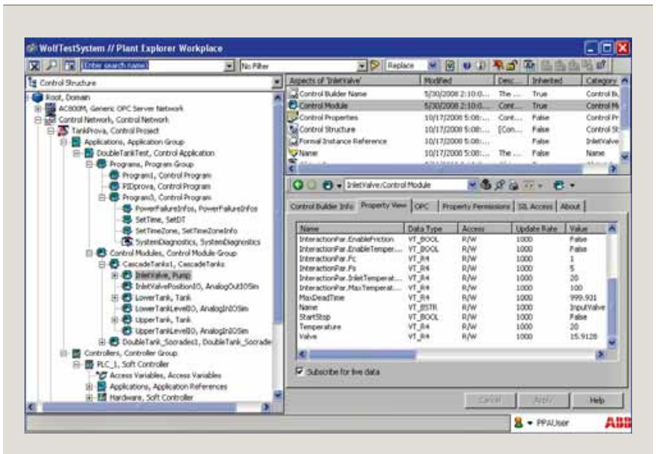
OPC UA at ABB

ABB was heavily involved in the creation of OPC UA. Several ABB employees were members of the OPC UA working group formed by the OPC Foundation. Over time, ABB members have edited three of the eight released specifications (ie, Address Space Model, Information Model and Security Model). With their broad software architecture expertise and extensive connections to experts, these employees helped to make decisions about the design and technology required to create a secure, reliable and high-performance OPC UA standard. A special focus for ABB was to ensure that the OPC UA information modeling concepts fit well with Extended Automation System 800xA's well-established and powerful Aspect Object Model. ABB's corporate research provided mapping concepts for integrating third-party OPC UA servers into System 800xA acting as an OPC UA client, and for integrating System 800xA, as an OPC UA server, into third-party OPC UA clients 4. A prototype implementation has proved that the OPC UA concepts can be applied to System 800xA easily.

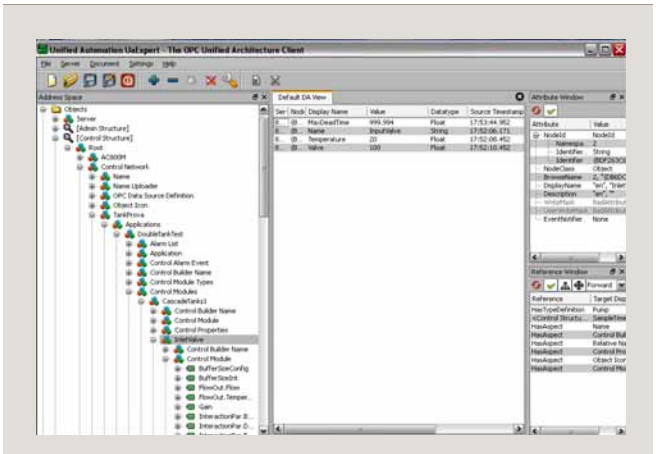
ABB is strongly supportive of OPC UA and has committed resources to ensure adequate training courses and presentations are available to introduce the OPC UA concepts. A third-party C++ based OPC UA software development kit (SDK) is provided for use within ABB. A sharepoint server

4 Typical screen shots from System 800xA

a System 800xA native view (Plant Explorer)



b System 800xA view using a generic OPC UA client



Footnotes

7) A communication stack is the software that implements a communication protocol across a computer network.

8) ANSI C is the American National Standards Institute's standard C programming language. By creating a standard for software developers writing in C the code is portable (ie, little effort is required to adapt it to a new environment).

9) The Microsoft.NET Framework is a software framework available with several Microsoft Windows operating systems intended to be used by most new applications created for the Windows platform.

10) A proxy server acts as a go-between for requests from clients seeking resources from other servers.

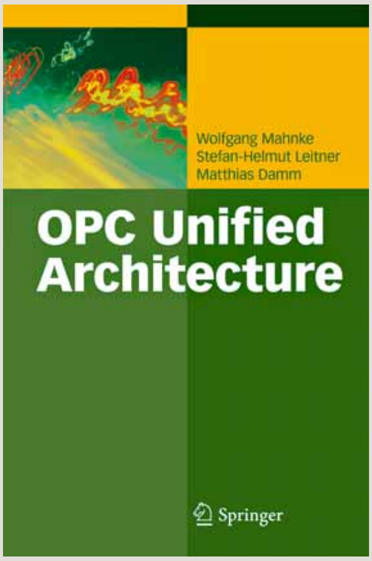
11) Anybody inside ABB can contact the authors of this article for training or access to ABB's sharepoint server.

Efficiency and standards

provides the latest news and SDK updates to keep the ABB OPC UA community informed worldwide[11)].

ABB also took part in the early adopter program of the OPC Foundation, helping to develop an ANSI C-based OPC UA stack, developing the security module and participating in code reviews. The portable design of the stack already allowed ABB to develop a port to VxWorks, a popular real-time operation system running on many ABB controllers like the AC800M and the robotics controller (IRC5). In addition, the OPC Foundation provides the stack with ports for Linux and Windows operating systems.

5 The authors have written a book, OPC Unified Architecture, which provides further discussion of advanced topics.



As the development of the specification was finalized ABB participated in several interoperability workshops organized by the OPC Foundation to ensure interoperability of ABB's OPC UA applications with third-party implementations, including those from ICONICS, Siemens, Beckhoff, Kepware, and OSISoft.

ABB is strongly supportive of OPC UA and has committed resources to ensure adequate training courses and presentations are available to introduce the OPC UA concepts.

ABB was involved in the development of standard information models based on OPC UA for field devices (FDI) and analyzer devices (ADI). In addition, ABB is a member of the PLCopen working group defining an OPC UA-based information model for IEC 61131-3 languages.

Internal presentations and training, together with ABB participation at several OPC UA developer conferences and other events, have emphasized ABB's leading role in OPC UA development and its position as technology leader. ABB's determination to provide an easy-to-read introduction to the OPC UA concept with further discussion of advanced topics is illustrated by its authorship of the first book written on OPC UA [11] 5.

OPC UA products

ABB is currently evaluating the application of OPC UA to certain ABB products. Others have already been evaluated and OPC UA-compatible products are on their way. Among these early products are SCADA Vantage™, which is due for release in 2010, and process analytical technology – PAT 2.0, which is already on the market as the first ABB product supporting OPC UA.

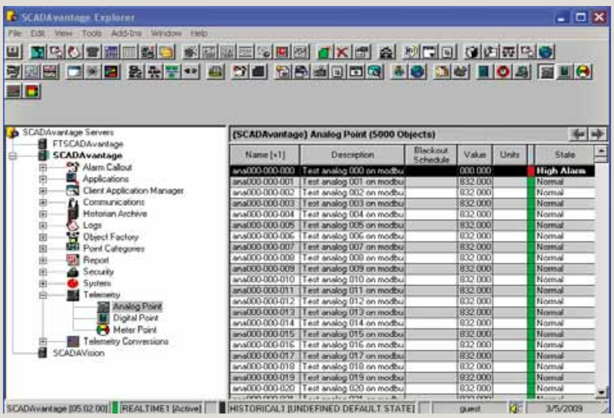
SCADA Vantage

ABB's Industrial^IT SCADA Vantage is a SCADA (Supervisory Control and Data Acquisition) system typically used in the oil and gas industry 6. The information provided includes instances and types, current data, alarms & events, and history. The same information can be exposed natively via an OPC UA server 7. Thus the SCADA Vantage data is exposed in a standardized way and can be used by third-party products as well as integrated into other ABB products having an OPC UA client. The release of SCADA Vantage with an OPC UA server is scheduled for 2010. Later versions will also have an OPC UA client to allow the integration of OPC UA servers into SCADA Vantage.

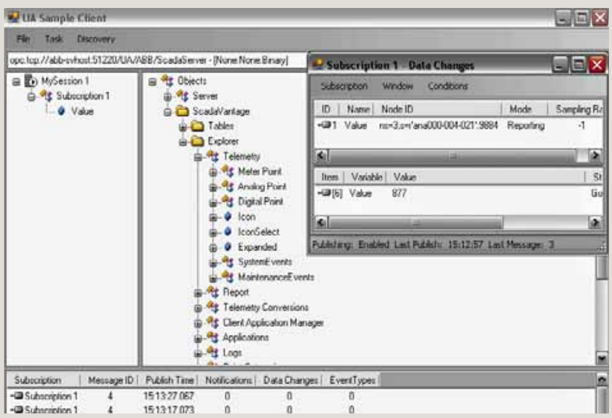
Process analytical technology

ABB's Industrial^IT eXtended PAT promotes the integration of analytical measurements into the manufacturing process and was released in 2007. A major upgrade with OPC UA support was released in Q1 2009. It utilizes OPC UA to provide standardized connectivity to process analyzers.

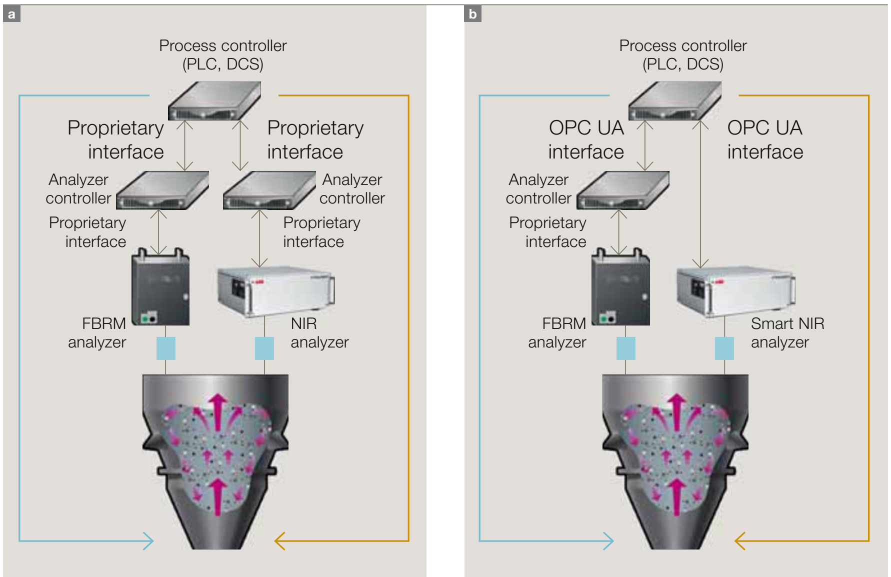
6 The SCADA Vantage native explorer



7 The SCADA Vantage OPC UA view



8 OPC UA helps xPAT integrate analyzers, either by using a proprietary interface for each analyzer provided by an analyzer controller a, or using OPC UA for all analyzer devices supporting OPC UA b.



With its powerful integration capabilities and functionality, xPAT helps customers in the life science industry implement quality, by design, throughout the entire pharmaceutical product life-cycle, from drug discovery through development to production.

Process analytical technology – PAT 2.0 – is already on the market as the first ABB product supporting OPC UA.

ABB's xPAT uses OPC UA when integrating analyzers 8. The OPC UA server can either be hosted on an analyzer controller or directly on the analyzer device and thus eliminate additional hardware. Using the ADI information model, it is not only possible to standardize how data is communicated, but also what data is exchanged.

Other suppliers

The first products from other suppliers have already been launched, even before the specification was released. This includes ICONICS' HMI/SCADA system, GENESIS 64, which also uses OPC UA for internal communication, Beckhoff's TwinCat and Kepware's KEPServerEx, both running on controllers, as well as Siemens' SIMATIC NET. For 2009, long lists of competitors have promised to deliver their first OPC UA products, including Emerson, Honeywell, Wonderware, and Yokogawa.

SCADA Vantage data is exposed in a standardized way and can be used by third-party products as well as integrated into other ABB products having an OPC UA client.

Prospects

OPC UA is ready to replace Classic OPC using state-of-the art, high-performance technology that is reliable and secure, raising interoperability in automation to a new level, by allowing standard information models based on OPC UA. With the wrappers and proxies provided by the OPC Foundation, existing OPC products are guaranteed to work within the OPC UA environment.

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[1] OPC Foundation: Devices, Draft Version 0.75, Dec. 2008
[2] OPC Foundation: Analyzer Devices, Draft Version 0.30.00, Dec. 2008
[3] OPC Foundation: UA Spec. Part 4 – Services, Version 1.01, Feb. 2009
[4] OPC Foundation: UA Spec. Part 3 – Address Space Model, Version 1.01, Feb. 2009
[5] OPC Foundation: UA Spec. Part 5 – Information Model, Version 1.01, Feb. 2009
[6] OPC Foundation: UA Spec. Part 8 – Data Access, Version 1.01, Feb. 2009
[7] OPC Foundation: UA Spec. Part 9 – Alarms and Conditions, DRAFT Version 0.93q, Nov. 2007
[8] OPC Foundation: UA Spec. Part 10 – Programs, Version 1.00, Jan. 2007
[9] OPC Foundation: UA Spec. Part 11 – Historical Access, Version 1.00, Jan. 2007
[10] OPC Foundation: UA Spec. Part 13 – Aggregates, RC Version 1.0, July 2008
[11] **Mahnke, W., Leitner, S.-H., Damm, M.** (2009). OPC Unified Architecture. Springer Verlag.

Further reading

OPC Foundation: UA Spec. Part 6 – Concepts, Version 1.00, Feb. 2009
OPC Foundation: UA Spec. Part 7 – Profiles, Version 1.00 Feb. 2009

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Not lost in translation

Facing the challenge of cost-effective plant engineering in subsystem integration

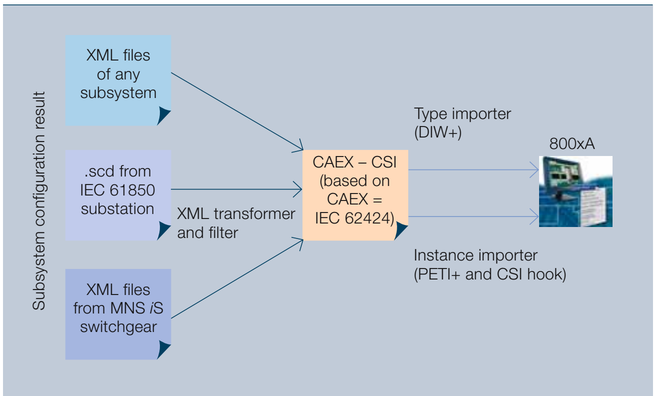
Peter Erning, Kurt Langer, Hartmut Rüdele, Dirk Schulz

Translating language is not always an easy task. Poor translations can lead to misunderstandings and even a total breakdown of communication. What is true of human language is even more true when it comes to automation systems. With different manufacturers using different standards, the integration of subsystems requires a translation of engineering data to enable communication with a distributed control system.

Distributed control systems, as are used, for example, in process or power plants, can achieve a considerable complexity and often integrate subsystems from different suppliers. For optimal integration, subsystem engineering data must be available to the overall control system. The challenge thus lies in translating this data to a format that the overlying control system understands. Of course manual translation of descriptions is possible but this is both labor intensive and error prone. ABB has developed a concept that permits the automatic translation of subsystem engineering data to ABB's own System 800xA automation system. Functional prototypes for the automatic integration of MNS *i*S low-voltage switchgear and IEC 61850 substation automation systems are available.

Early distributed control systems DCSs for process automation were homogeneous solutions provided by single suppliers. These suppliers were able to deliver almost all system components and to perform the engineering using their own specific engineering tools. Over the years, process-automation architectures have become more heterogeneous. Due to the rapid development in the microelectronics area, control and advanced functionalities have increasingly found their way to the field level of industrial plants.

1 Integrator system concept



The challenge is to provide a flexible software tool that enables an automated import of all engineering data from any previous engineering of a subsystem to a DCS with minimized manual effort.

With regard to automation systems, this means that today entire subsystems are being integrated into DCSs. Subsystems from different manufacturers are based on different architectures must therefore be able to communicate and act as one DCS. For example data from one subsystem must be accessible throughout the entire DCS. To achieve this, the engineering architecture of the subsystem must be visible to the main control system.

The main common characteristic of the subsystems discussed in this article is that they have DCS-independent but subsystem-specific engineering process. Examples are fieldbus networks of intelligent field devices, low-, medium- and high-voltage switchgear systems, and process-specific machinery and equipment.

The challenge is to provide a flexible software tool that enables an automated import of all engineering data from any previous engineering of a subsystem to a DCS with minimized manual effort. To achieve this, ABB initiated a research project to automate the import of engineering data from ABB's MNS *iS*[1] low-voltage switchgear systems and IEC 61850-based substations[2] into ABB's System 800xA automation platform.

Problem description and scope

Plant engineering projects typically involve different partners and suppliers. The complexity of the engineering process and the corresponding engineering effort depend on many factors: plant type, phase of the project-engineering lifecycle, system architectures, scope of deliveries, product specifics, tools and documentation (on paper, computer readable formats and others used by the members of separate teams in different companies), data storage and information exchange between substructures (sub-systems) of the plant.

Regarding the plant-automation part, a control system can be considered an assembly of a traditional DCS and other subsystems that also exhibit some DCS characteristics with regard to their architecture, instrumentation, control, communication and engineering tools. Examples are fieldbus systems; low-, medium-, high-voltage (LV, MV, HV) switchgear systems; and process-specific machinery and equipment.

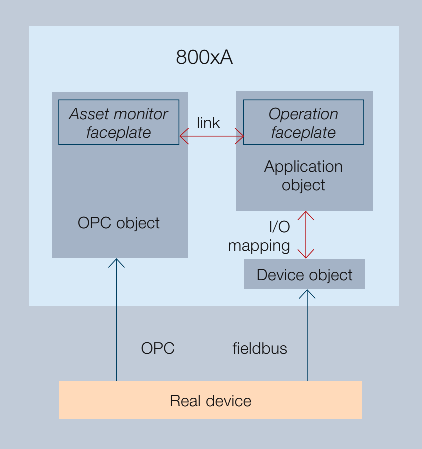
This article focuses on a method that is suitable for the automatic import of all engineering data of a subsystem that are needed on the DCS level, avoiding a subsequent manual entry of data that are already available in the subsystem tool(s).

Footnotes

1) MNS *iS* is an ABB low-voltage switchgear platform. MNS stands for Modulare Niederspannungs-Schaltanlage (modular low-voltage switchgear).

2) IEC 61850 is a modern standard for substation communication and integration.

2 Object model in System 800xA



Factbox Customer and ABB internal benefit

The described concept and solution has the following advantages:

- Manual engineering work for subsystem integration is reduced to the configuration of the importer tools and the enrichment of the object types. This remaining engineering work is almost independent of the size of a subsystem because object instances are created automatically. The engineering time is drastically reduced and the quality is improved.
- The concept enables a split of the import tool responsibilities between the subsystem supplier and the DCS supplier.
- The subsystem provider does not need to take into consideration the special interfaces and future changes on the System 800xA side. All required actions for integration can be modeled in an XML file (CAEX-CSI) created by a subsystem-specific transformer.
- The DCS supplier is responsible for common importer tools on the System 800xA side, also assuring a proper handling of a second upload in case of changes.
- The concept is prepared for existing and future protocols (PROFIBUS, Profinet IO, IEC 61850, OPC, etc).
- Engineering workflows with different delivery schedules can be handled in a better way (see section “Ongoing development”).

The “subsystem” in this context can be any system with the following characteristics:

1. The subsystem’s engineering data are available in computer readable format.
2. The subsystem provides at least one open communication interface.

The integration of engineering data can be achieved manually, but this leads to both a high risk of errors and unnecessary effort. The development of system-specific integration tools therefore represents an attractive alternative. However, these tools have to include expert knowledge of both the system that is to be integrated and the target DCS (which in the context of this article is ABB’s System 800xA extended automation system).

The syntax of the intermediate file is independent of the respective subsystem. This achieves a decoupling of the subsystems from the DCS.

Hence a generic concept for the import of external engineering data into System 800xA is a strongly desirable objective. The import mechanism should automatically create and configure objects in System 800xA based on the data contained in the subsystem’s specific engineering files. The mechanism must provide for objects that communicate via multiple communication paths (eg, fieldbuses, OPC[3]) but should provide a common interface to the user. System 800xA possesses an object-oriented architecture. For maximum benefit this should also be reflected in structures imported from subsystems. Subsystems often define project-specific object types, which must also be created in System 800xA and provided with a customized graphical interface. This tailoring should be done on the object-type level rather than on the instance level. Furthermore, the integration concept should provide a generic approach instead of separate integrator tools for every subsystem (the latter would lead to high maintenance costs). The import mechanism also has to take into account changes in the initial engineering data and should offer second upload capabilities (ie, intelligent change management). Finally, in order to minimize additional maintenance effort, existing tools from the System 800xA environment should be reused as far as possible.

Solution approach

In order to address these challenges, a generic importer concept was developed. The concept’s overall topology is shown in 1. The subsystem-specific data files are transformed into an intermediate file, which then serves as input for the actual import tools that create and configure the corresponding objects in the System 800xA DCS. The use of a subsystem-independent intermediate file achieves the desired decoupling of the subsystem’s knowledge domain from the DCS knowledge domain.

This concept relies on the interaction of several software components. First, a so-called transformer has to convert the subsystem-specific information. All information that exists in the specific XML files and that should be available in the DCS has to be extracted and transformed into the intermediate format. This information can, eg, comprise control and monitoring data, location information and documentation data. It should be pointed out that the engineering data do not necessarily conform to the object-oriented paradigm. Hence it can become necessary to analyze the properties of the individual objects, group similar objects, and define corresponding type and instance trees.

Footnotes

[3] OPC is a standard for real-time communication between control devices from different manufacturers. Today, OPC is officially a name and not an acronym, but originally stood for OLE for Process Control. OLE stands for Object Linking and Embedding, a document embedding and linking technology also developed by Microsoft. See also “OPC Unified Architecture” on page 56 of this edition of *ABB Review*.

[4] CAEX: Computer Aided Engineering eXchange, a neutral data exchange format for plant information defined by IEC 62424. CAEX-CSI stands for CAEX Complex device & Subsystem Integration (name of the research project)

The pivotal part of the whole concept is the intermediate data format (CAEX-CSI).[4] The syntax of the intermediate file is independent of the respective subsystem. This achieves a decoupling of the subsystems from the DCS. The file contains definitions for the utilized devices and subsystem types as well as information about the instance hierarchy. The type information can be stored explicitly in the intermediate file itself. In order to reduce transformation effort, it is also possible to specify links to the corresponding device description files (eg, GSD[5] files for PROFIBUS devices).

The import of the information contained in the intermediate files is achieved in two steps. First, the type information is analyzed and the corresponding types are created in System 800xA. After type import, manual alterations (eg, creation of graphical interfaces) can be effected on the newly created types. As a next step, the instance information is parsed, the device hierarchy is generated in the DCS and the device objects are instantiated and configured.

Typically, there is more than one instance per device 2: a device object for retrieving the raw process data and an application object to process the data and display them on an operator faceplate. In case of an additional communication path such as OPC there is even a third instance equipped with an asset monitor. The necessary interconnection of these objects is also automatically implemented by the instance importer.

Achievements

Functional prototypes have been developed for two types of subsystem, the new ABB LV switchgear system MNS *i*S and IEC 61850-based high- or medium-voltage systems. In both cases, XML-based system descriptions are available from the specific subsystem engineering tools. First transformer versions for MNS *i*S and IEC 61850 are available.

> Functional prototypes have been developed for two types of subsystem, the new ABB LV switchgear system MNS *i*S and IEC 61850-based high- or medium-voltage systems.

The CAEX-CSI data importer consists of the following prototypical components:

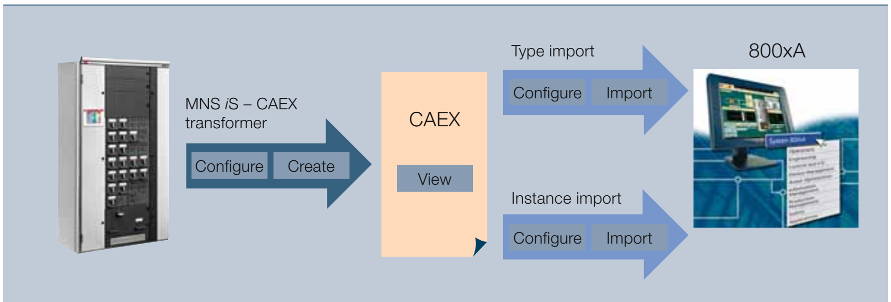
- DIW (device import wizard) that is used for the object type import is an ABB product that was extended with some functionality (see 1, prototype “DIW+”).
- PETI (process engineering tool integration) is an existing ABB product that is capable of importing instances from CAEX, including a proper handling of a second upload in case of changes. The next PETI version will satisfy some additional CSI requirements (see 1, “PETI+”).
- A special aspect system (“CSI hook”), which ensures that each object gets a working OPC connection and a correct link to an object specific faceplate.

The transformation and import workflow is supported by a lightweight frame application. The MNS *i*S frame application is depicted in 3. It connects the above components and guides the user through the individual integration steps.

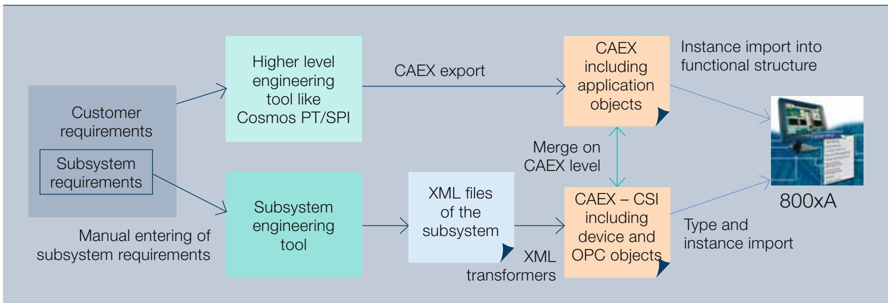
Ongoing development

Beside the activities to develop existing prototype importers into products, there will be an additional focus on overall engineering workflows. It is not uncommon in a plant-project schedule for decisions on subsystems to be taken later than the DCS engineering stage. Consequently, additional data coming from plant engineering tools (eg, Comos from Innotec or SmartPlant from Intergraph) also have to be used and will be merged with data coming from the subsystem 4.

3 Engineering data integration workflow



4 CAEX simplifies merging of multiple paths of engineering data



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Footnote
[5] GSD: Geräte-Stamm-Daten (device master data), a PROFIBUS description file

High-voltage bushings

100 years of technical advancement

Lars Jonsson, Rutger Johansson

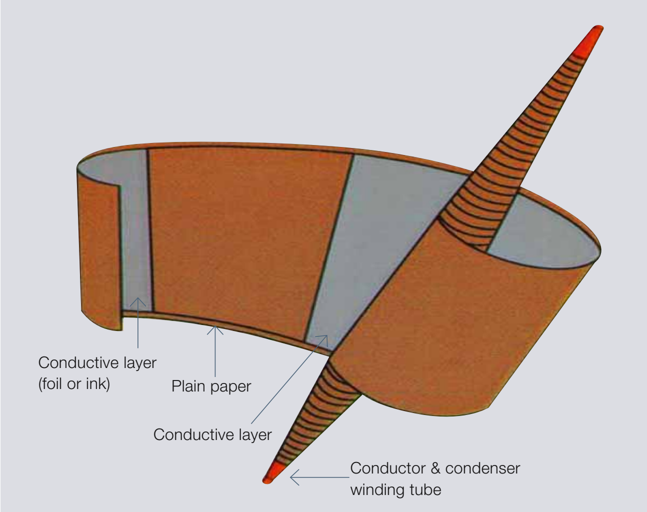
Reliability has always been one of the core demands of the energy market. One such example of reliability can be seen in the exceptional lifetime of power transformers, which often function for 50 years or more. This core demand is also fundamental for high-voltage bushings – critical components of all electrical networks, as their chief role is to prevent flashovers to ground.

Although many in the electric utility industry still regard the bushing as nothing more than a hollow piece of porcelain housing a conductor, the task it performs is quite extraordinary, involving advanced technologies in manufacturing and design with a lifetime exceeding the requirements of its applications.

Sophisticated calculation and design tools, improved material and production technology, and broad expertise are a result of over 100 years of experience in bushings, developed and manufactured at ABB in Sweden. As the world's largest supplier of bushings, ABB's flagship plant in Ludvika, Sweden, is equipped with state-of-the-art production lines that meet the increased demands associated with increasing voltage levels and reliability needs.

A bushing serves to insulate conductors that are carrying high-voltage current through a grounded enclosure. To safely accomplish such a task without a flash-over is a challenge, as the dimensions of the bushing are very small compared with the dimensions of the equipment it is connecting. Controlling the stress (ie, electrical voltage, thermal current and mechanical stress) to get the dimensions right is of utmost importance in terms of bushing performance in the field during its lifetime.

1 Schematic view of condenser core



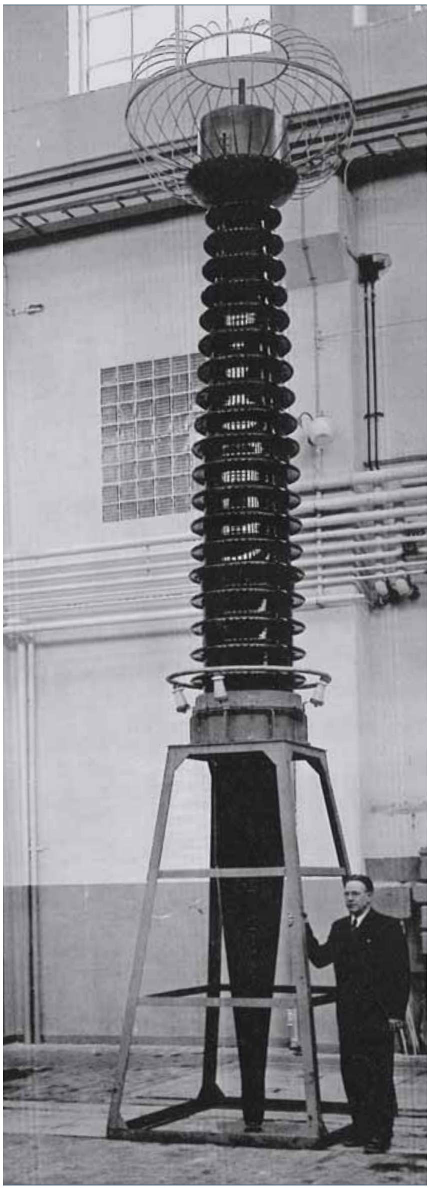
High-voltage condenser bushings

Condenser bushings facilitate electric stress control through the insertion of cylindrically applied floating equalizer screens made of aluminum. The condenser core in which the screens are located decreases the field gradient and distributes the field along the length of the insulator, distributing it radially and axially in the condenser core 1. The screens are located coaxially, to ensure the optimal balance between external flashover and internal puncture strength (ie, the electrical withstand of the condenser core).

At the start of the 20th century, bushings were dry insulated, made of Bakelite (resin-coated) paper and aluminum foil, with a flange glued to the condenser core and an insulator made of porcelain.

For years, condenser bushings have maintained the same basic design. Special paper envelopes the conductor, with metallic electrodes strategically placed inside the wrapping. These control the electric field of the bushing. The cylinder is impregnated with transformer-grade mineral oil or epoxy resin to further increase the electrical withstand, beyond that possible with only dry paper. The bushing is therefore an enclosed apparatus fully separated from its application environment.

400 kV AC bushing from the 1950s



Oil-impregnated paper (OIP) and resin-impregnated paper (RIP) are the two main technologies in high-voltage condenser bushings. RIP technology is making a valuable contribution to better overall performance figures. The somewhat differently designed condenser core is vacuum impregnated by a curable epoxy resin to form a solid unit, free from oil 2.

Both systems are designed and manufactured for long lifetimes and trouble-free performance, ensuring low partial discharge readings at well above the nominal voltage and ample margins for thermal runaways and overheating.

The outer insulation can be either ceramic or polymeric. Ceramic insulators have a long history and will be used for many years to come. However, it is likely that their role will diminish in the foreseeable future as the industry seeks improved insulator performance in order to reduce overall costs and improve safety, seismic withstand and pollution performance, as well as reduce insulator weights.

Controlling the electrical voltage, thermal current and mechanical stress to get the bushing dimensions right is of utmost importance.

To meet as many requirements as possible, bushings are configurable and are produced for system voltages up to 1,100 kV AC and 800 kV DC – even higher for test purposes. The largest bushing developed and manufactured at the Ludvika plant is an 1,800 kV AC transformer bushing with a length of 15 m. The limitation for the plant is not the voltage levels or bushing sizes, but rather the market need, where 1,100 kV AC and 800 kV DC are the highest voltages used today.

PERPETUAL PIONEERING

Historical review of bushings

At the start of the 20th century, bushings were dry insulated, made of Bakelite (resin-coated) paper and aluminum foil, with a flange glued to the condenser core and an insulator made of porcelain. These were suitable for voltages up to 190 kV.

Voltages increased to 220 kV in the 1930s and the conductive layers were changed to graphite. The graphite (ie, the semiconductive layer) concept is still used today by some manufacturers. The space between the condenser core and outer insulation is filled with oil and is open to the transformer.

In the 1960s, oil-impregnated bushings became the predominant technology – even today they have a market share of more than 80 percent.

In the 1940s, voltages rose to 400 kV, and condenser cores impregnated with oil and placed inside an insulating envelope of oil and porcelain were introduced.

But the early bushings had a high partial discharge and dissipation factor (tan δ), which increased with rising system voltage. While sufficient for lower voltages, they left little margin for increasing applications. As voltages rose to 765 kV in the early ’60s, this old technology was replaced with OIP systems. ABB thus supplied the first 705 kV bushings to Hydro Quebec in Canada.

At that time, oil-impregnated bushings became the predominant technology (this is still true today with a present market share of more than 80 percent). OIP bushings continued to be developed and resin-bounded bushing production was discontinued. Dry bushings, often referred to as RIP bushings, were introduced and have a growing market share.

In the 1970s, development of HVDC bushings for 600 kV began, and test installations requiring bushings for 1,800 kV AC were also underway. Even though both systems were oil insulated, they were significantly different in design.

RIP bushing development, which began in the ‘60s at ABB’s Swiss sister plant, resulted in the production of 420 kV bushings in 1989 and 525 kV bushings in 1996. The reintroduction of dry technology is the direct result of powerful modern calculation tools as well as progress in material and production technology.

Recent (2006) HVDC transformer and wall bushings for 800 kV DC were developed and verified through extensive short- and long-term testing. The material properties change with time under DC stress and therefore long-term testing enables verification of the DC design before putting a new product into service. Based on experience in design, production processes and the latest achievements in calculation tools development, complex mechanisms such as ion migration and time-dependent charge distributions have been taken into consideration. The next step may well be 1,000 kV DC as a logical continuation of the achieved knowledge during the development of the 800 kV DC bushings.

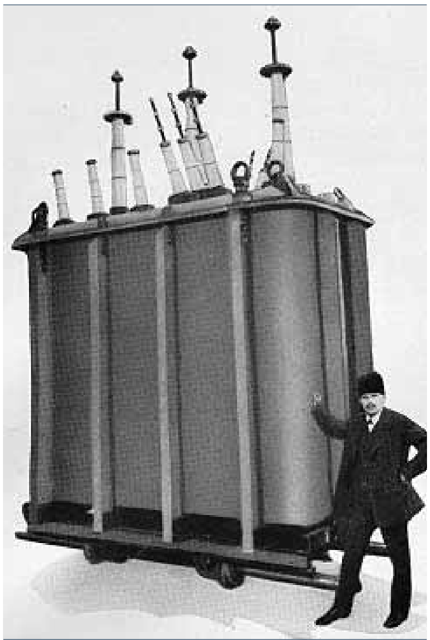
Bushings are configurable and are produced for system voltages up to 1,100 kV AC and 800 kV DC.

In 2007, ABB designed and delivered AC bushings for up to 1,100 kV to China, and the long-established level for AC networks was increased from 800 kV to 1,000 kV AC 3. This design relied on the knowledge from the 1,800 kV designs of the 1970s.

2 Impregnation of RIP bushings

3 Installation of 1,100 kV AC bushing (2008)

Transformer from the early part of last century



Developing bushings for increasingly higher voltages and complex applications requires a great amount of experience and knowledge, as well as testing facilities far above the rated voltages – all of which are available at ABB today.

Technical challenges

Inherent in such complex devices are of course technical challenges. The highest voltage for equipment is generally limited by physical dimensions (ie, longer distances have higher electrical withstand). Also at high voltage levels another complication arises – namely the dielectric heating of the insulation. While the dielectric losses in a properly processed bushing can be neglected at low voltages, they become substantial at high voltage levels.

Insulation material has its lowest dissipation factor at approximately 60 °C and then increases with temperature. The heat has to be dissipated through the insulation and bushing surface. Thus, for each bushing, a limit exists that if exceeded will result in insufficient heat dissipation and consequently an uncontrolled temperature increase. This phenomenon, known as a thermal runaway, will eventually result in a breakdown.

In 2007, ABB designed and delivered AC bushings for up to 1,100 kV to China, and the long-established level for AC networks was increased from 800 kV to 1,000 kV AC.

The dissipation limit is called thermal stability. Bushings naturally require full thermal stability at their highest voltage level while considering both the ohmic losses originating from the load current as well as the capacitive losses described earlier. The maximum allowed currents for a specific bushing and the dielectric losses coming from the voltage must therefore be judged both together and separately. For a properly designed bushing, the dielectric losses and the rated current are not critical, and low-loss requirements do not contribute to the service life.

RIP technology represents a much larger challenge than OIP technology. This is because oil impregnation under vacuum is a relatively straightforward and forgiving process in the sense that oil fills out all parts of the bushing and remains in a liquid phase throughout its entire life. Void-free products must be developed and manufactured with special attention, using the latest design tools.

To fully simulate the very specific manufacturing process, where exothermic reaction, thermo-chemical shrinkage and air circulations take place, it is necessary to include relevant mathematical equations in the theoretical models. Simulation-based modeling provides for cause-and-effect analysis, without which imperfec-

Konti Skan II transformer fitted with Ludvika bushings. Konti Skan is the HVDC transmission line between Denmark and Sweden.

800 kV DC converter transformer (2008)

PERPETUAL PIONEERING

New UHV test facility (2009)

tions such as incorrect curing propagation, high temperature gradients, local overheating, high strain and stress (cracks), and shrinkage can occur. Besides numerical simulations of the manufacturing process, significant attention is placed on proper material selection, tailoring RIP materials for manufacturing optimization while taking into account field performance.

ABB is at the cutting edge in optimizing processes to reach ever higher degrees of reliability and quality.

Both OIP and RIP bushings are complex products, which, compared with the products available on a global scale, require high investments in equipment as well as research and development. The complexity rises heavily with increased voltages and currents. But these challenges push ABB to create optimized, state-of-the-art bushings for its customers.

Quality assurance

Bushing production processes have seen decades of continual development resulting in extremely high yields. This does not, of course, mean that the end of the road has been reached.

ABB is at the cutting edge in optimizing processes to reach ever higher degrees of reliability and quality. This is evident in the most critical manufacturing steps, for example in the winding of the condenser cores where state-of-the-art machines control the winding and equalizer screen insertion, or during drying and impregnation where the process is controlled and monitored by computers and highly experienced teams working with machines.

Another area that has seen excellent advancement over the years is statistic process control and the automatic checking of process limit values with the implementation of new technology.

A global reporting network is in place, requiring all ABB units to report all major events within 24 hours. This provides a good base for event classifications. Cross-functional meetings are held to review and prioritize this information and implement the subsequent corrective or preventive actions in design and production.

ABB's role in bushing production and development is strong, with sites in Brazil, China, India, Russia, South Africa, Switzerland, the United States, and particularly Sweden.

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Further reading

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A celebration of innovation

The achievement of something that is radically new, that has never been reached before, is in itself a fascinating experience. At ABB, this is even more so if the new idea can open up real advantages for customers or society as a whole. Hundreds of scientists and engineers in ABB's corporate research centers and in the divisions across the globe are continuously pursuing such innovations, many of which will define the products and applications of tomorrow.

Every year, the fourth edition of *ABB Review* is dedicated to presenting the best innovations of that year. Selecting these is no easy task and those finally selected represent only a cross section of what has been achieved.

One such technological innovation is shown in the picture above: a control panel of **Busch**-***priOn***® – part of the intelligent room-control concept developed by Busch-Jaeger, a member of the ABB Group. The luminescent aura of this panel looks like a futuristic design in itself, but there is more to it than first meets the eye: The color actually changes dependent on the context (the aspect being controlled), leveraging an intuitive and easy-to-understand approach to a powerful multifunctional interface. This concept was awarded the internationally renowned "red dot design award" for its innovation in communication design.