Power Up Your Plant An introduction to integrated process and power automation

Jeffrey Vasel ABB, Inc.

January 15, 2010

Abstract

This paper discusses how a single integrated system can increase energy efficiency, improve plant uptime, and lower life cycle costs. Often referred to as Electrical Integration, Integrated Process and Power Automation is a new system integration architecture and power strategy that addresses the needs of the process and power generation industries. The architecture is based on Industrial Ethernet standards such as IEC 61850 and Profinet as well as Fieldbus technologies. Emphasis is placed on tying the IEC 61850 substation automation standard with the process control system. The energy efficiency gains from integration are discussed in a power generation use case. In this use case, energy efficiency is explored with integrated variable frequency drives, improved visibility into power consumption, and energy efficiency through faster plant startup times. Demonstrated capital expenditure (CAPEX) savings is discussed in a cost avoidance section where a real world example of wiring savings is described. Lastly, a power management success story from a major oil and gas company, Petrobras, is discussed. In this case, Petrobras utilized integrated process and power automation to lower CAPEX, operational expenditure (OPEX), and explore future energy saving opportunities. This page left intentionally blank.

What is integrated process and power automation?

Integrated process and power automation is a unified architecture that combines process controls, process electrification, and power management and distribution into one system. Often referred to as Electrical Integration, integrated process and power automation is a new system integration architecture and power strategy that addresses the needs of many process industry segments. Electrical Integration is the next frontier in driving energy efficiency, increasing availability and operator effectiveness, and reducing costs.

A typical process control plant can be divided into three areas: Process Control, Process Electrification, and Power Management and Distribution as shown in Figure 1.

Process Control

Includes instrumentation, safety systems, and controllers. Here these devices communicate using a variety of fieldbus protocols including Profibus, Foundation Fieldbus, and HART.

• <u>Process Electrification</u>

Includes low voltage (LV) drives, motors, switchgear, and circuit breakers. These devices typically communicate with the control system via Profibus and Modbus. Profinet is now making its debut into the Process Electrification area.

Power Management and Distribution

Corresponds to Substation Automation (SA) systems. It hosts medium voltage (MV) and high voltage (HV) power equipment including protective relays, also known as Intelligent Electrical Devices (IEDs), transformers, instrument transformers, power meters, drives, and motors.

This architecture is primarily for industries that consume a great deal of energy. These industries have different objectives. The oil and gas industry wants to maximize production, so production facilities need to do fast load shedding during power interruptions to keep their critical processes running. Mining and minerals processing facilities also want to maximize production but they need a consistent and reliable supply of energy as well as efficient power distribution. Power generation facilities desire to create a reliable supply of energy and address high energy consumption with peak shaving.



Figure 1 – Integrated process and power automation for a typical process plant system

The IEC 61850 standard and the DCS

Electrical integration in the past has been hampered with lack of communication standards and architectural design resulting in high project execution and commissioning costs and high life cycle costs. There are too many protocols used in substation automation systems. Some are proprietary while others are open standards. No one protocol has become dominant. As a result, the cost to engineer the SA system is high when multiple vendors supply equipment that uses different communications protocols. The life cycle costs of a system with a hodgepodge set of communication links are also very high. In addition, Electrical Integration is not new. It has been done in the past by hard-wiring signals between the electrical equipment and the process control system, as well as by building complex software gateways. Past integration methodologies have high integration costs, high project risks, and high life cycle costs. See Figure 2. Moreover, organizational barriers among departments within plants and suppliers have also hampered integration efforts. A new approach is needed to overcome these barriers¹.

Leading process control suppliers are taking advantage of open industry standards including Fieldbus technology and Industrial Ethernet to optimize commissioning efforts, minimize project risks, and lower the total cost of ownership. The Electrical Integration architecture is based on Industrial Ethernet standards such as IEC 61850 and Profinet as well as Fieldbus technologies. ABB's solution integrates power and process automation systems with the Electrical Integration architecture.



Figure 2 – Typical Electrical Integration architecture of the past

With the Electrical Integration architecture, all devices communicate back to the main control system using their individual open protocols. See Figure 3. Electrical Integration bridges two worlds: The instrument group and the electrical group now work together as they share a common system. An integrated system provides a unified way to maintain the entire plant. A true integration platform is needed to seamlessly combine the electrical control system, process control system, plantwide data historians, and maintenance equipment health information. This enables personnel to make informed decisions on energy management, life cycle management, and uptime on a plant-by-plant, process-by-process, or global basis, as user needs dictate. The platform is used as a common engineering and production interface for process control, electrical, and safety systems. Since it is the same system framework for both process and electrical control systems, it is very simple to implement the Electrical Integration architecture¹.



Figure 3 – Unified Approach to Automation and Electrical Integration increases productivity and decreases downtime

What is IEC 61850?

IEC 61850 is a global communication standard for power distribution and substation automation. Often people consider it a European standard, but it is a global standard common for both IEC and ANSI. IEC 61850 features a flexible and open architecture for MV and HV devices. It is implemented on Ethernet but it is not tied to Ethernet. It is often referred to as future-proof, as the standard will be able to follow changes in communication technologies².

Ethernet provides fast, reliable, and secure communications. Using a standardized model and communication language, the standard provides interoperability among electrical devices. Now end users can select equipment from a variety of suppliers and know that the equipment will operate and communicate together without having to create custom interfaces. IEC 61850 has a standard data modeling and naming convention. It has self describing devices, virtualized modeling of logical devices, and a common language to configure devices. Various functions are modeled with logical nodes. Logical nodes contain data for a specific function. The IEC 61850 standard allows application engineers the ability to add multiple nodes within a physical device. See Figure 4.



Figure 4 – IEC 61850 example structure of a protective relay 3

An example of dataset naming of Modbus versus IEC 61850 is illustrated in Figure 5. The Modbus dataset must be precisely mapped and must specify the register address. Modbus does not have a naming standard, so a data dictionary must be created for each Modbus system design. When two or more suppliers are used on a project, there will be multiple naming conventions and data mapping issues resulting in extensive testing and commissioning time. Future changes and modifications will be difficult and costly to implement. The register address will vary from device to device, while the IEC 61850 dataset naming is standardized and independent of register addresses. The case in Figure 5 shows the anatomy of an IEC 61850 standardized name. It describes the name from the voltage level down to the attributes of a specific piece of data including bay, IED, logical device, and logical node names. Using IEC 61850 simplifies SA communication system designs.



Figure 5 – Modbus dataset naming versus IEC 61850

Fundamentals of the IEC 61850 standard and Electrical Integration

Integration of data is done vertically and horizontally with Electrical Integration. See Figure 6. Non time-critical data such as alarms and events, circuit breaker status, and disturbance recordings are integrated vertically through an IEC 61850 OPC server. Vertical communication is done with Manufacture Messaging Specification (MMS). Report Control Blocks (RCBs) define the type of information sent from the IED to its clients via the OPC server. RCBs are event triggered and can be buffered within the IED. The events are time stamped by the IED before being sent to the OPC server. This will become critical when discussing the possibility of a single plantwide sequence of events list. For fast time-critical communication among electrical devices, Generic Object Oriented Substation Event messaging or GOOSE is used. GOOSE can transmit any type of process data between IEDs.

The controller in Figure 6 has dual roles. On one hand, it acts as a process controller on the control network. Here it concerns itself with temperatures and pressures and performs control actions with PID loops as control outputs. Its second function is to act as an IED on the substation's IEC 61850 network. The controller is now transformed into an IED and communicates horizontally with the other IEDs in the substation. While on the substation network, the controller reads voltages and currents and performs actions such as fast load shedding with GOOSE in the event of a power glitch.



Figure 6 – Vertical and horizontal integration with the System 800xA DCS via IEC 61850

GOOSE messaging is a peer-to-peer broadcast message, while Manufacture Messaging Specification (MMS) is a client server communication to the system level. GOOSE messages are continuously broadcast at a specific time interval to ensure reception of the data. The frequency of the broadcasts slows with each interval until a maximum time period is reached in order to better manage network bandwidth. The GOOSE message will continue to be broadcast at the maximum time period until a value in the message's dataset changes. At this point, the message will be broadcasted at a high frequency and then gradually slow down until the maximum time period is reached unless a value within the dataset changes.

Using Ethernet requires highly reliable network equipment. Commonly available network devices, however, will not hold up very well in the harsh environment of substations. Substations experience EMI surges as well as a wide range of temperature changes. The IEC 61850-3 standard outlines requirements for EMI and environmental conditions. There are several leading suppliers of network devices who see these implementation problems as an opportunity. Today, network equipment is available that will operate reliably in the electrically harsh environments of substations.

Security continues to be a concern and a high priority for suppliers and end users of computer equipment. GOOSE messages are sent at level 2 of the ISO/OSI TCP/IP stack. As a result, GOOSE messages cannot be transmitted through routers or firewalls. Hackers outside the firewall will have a difficult if not impossible time in sending rogue GOOSE messages. The North American Electric Reliability Council (NERC) and Critical Infrastructure Protection (CIP) have requirements for network equipment used in substations. Key suppliers of IT assets are designing and building network equipment that complies with these standards. Even with the high security that GOOSE messaging provides, improving and upgrading security measures will be a continuous effort for both suppliers and end users of IEC 61850.

Benefits of the IEC 61850 standard

IEC 61850 Ethernet versus hard-wired signals: Which is faster?

If there were two hard-wired IEDs and an identical pair of IEDs communicating GOOSE over Ethernet, which pair of IEDs will communicate faster? In many cases, GOOSE messages are faster than hard-wired signals among IEDs because the hard-wired signal must go through an output contact on the sending relay and then again on an input contact on the receiving relay. IEC 61850 is the fastest substation automation communication standard currently available in the marketplace.

Network traffic is a concern when critical signals need to be sent to other IEDs. Many network switches have the ability to prioritize GOOSE telegrams; this way the critical information passes ahead of other network traffic.

IEC 61850 Ethernet versus hard-wired signals: Which is more reliable?

Connectivity among IEDs is automatically supervised by GOOSE. GOOSE sends out a quality byte with each telegram. If the quality is bad or poor, the application can notify operators of a problem in the network. Each GOOSE message is repeated continuously until the data set values change. Each GOOSE message has a counter as well. The recipient of the GOOSE message can compare the counter value to the last one to see if it has missed a message and then take appropriate action. Or if the repeating message is not received in a certain period of time, then the recipients can take action. In either case, the connectivity failure is detected. In the case of hard-wired IEDs, detecting a break in the signal wiring may not be possible.

Benefits of integration

Power generation use case

Introduction

Figure 7 below shows a fully integrated power generation plant system. It is similar to the generic Electrical Integration diagram shown in Figure 1. The integrated power plant system is divided into three areas:

- 1. Turbine Controls System (TCS)
- 2. Boiler and balance of plant control, also known as Distributed Control System (DCS)
- 3. Electrical Control System (ECS).

Today's sophisticated DCS controllers can integrate multiple Fieldbuses into a single controller providing the end users with a freedom of choice for Fieldbus technology⁴. In the TCS section, Fieldbus communication interface modules are used to integrate the turbine controls such as turbine valve position, auto synchronization, turbine position, and vibration condition monitoring into the controller. This eliminates the need for separate communication hardware resulting in a simpler design. Once the TCS data is in the controller, diagnostic and process information is made available to all necessary plant areas such as the DCS and ECS.

One platform to learn equates to shorter training periods for plant personnel including operators, engineers, planners, and managers. The same controller, I/O modules, and engineering tools are used in the balance of plant as in the TCS. In addition, fewer spare parts are required. An integrated system protects assets and can help promote the safety of personnel while optimizing plant operations and reducing life cycle costs.

NERC and CIP security and compliancy is made easier with an integrated system. A common audit trail for the entire plant is possible. In addition, only one system will need to be updated with software security patches. It is easier and cheaper to maintain security on one system than it is to secure multiple systems.



Figure 7 – Integrated process and power automation for a power plant system

Energy efficiency with integrated VFDs

Power plant auxiliary system power usage is on the rise. In fact, 7 to 15% of generated power is used by the power plant's auxiliary systems⁵. This number is increasing due to the addition of anti-pollution systems and an increase in cooling water pumping needs to control thermal discharge issues. Today, modern plants are still using direct connect motors with throttling valves to control flow. By replacing them with integrated variable frequency drives (VFDs), the expected energy savings is substantial. Figure 8 shows a chart of percent power required versus percent flow. According to the chart, when operating a direct connect motor at 50% flow, the power required is 68% of what it would be at maximum flow. When using a VFD, the power consumed is only 22% of maximum power. This equates to 67% less power consumed when using a VFD versus a direct connect motor.





Energy Efficiency through improved visibility into power consumption

Plant electrical information is available but often it is difficult to view. By taking advantage of an integrated architecture, critical power data is more readily available. With this critical data, power usage can be observed, monitored, and studied. It provides better visibility into power consumption and real-time energy usage and costs. It also allows for easier energy audits and benchmarking.

An integrated system enables operators to understand and easily access power usage. New energy savings opportunities can be explored, while existing energy reduction programs can be enhanced. An integrated system provides a centralized historical data source. Now energy consumption can be tracked plant-wide from one database. For example, an increase in power consumption by a unit or an area can indicate equipment malfunction and wear. Without visibility into power consumption, the problem may go unnoticed which could result in unexpected downtime plus a preventable increase in energy usage.

Another advantage to an integrated system is immediate visibility of any power event such as bus transfer, load sheds, or trips from any operator station. The status of critical electrical equipment can be seen, alerting operators to potential system problems. Information can be provided via alarm and events lists as well as email and text messaging notifications. Work orders can automatically be opened to a Computerized Maintenance Management System (CMMS). Whether it is an electrical glitch, process control problem, or a failing IT asset, plant operators will have complete visibility and control of the situation.

Energy efficiency through faster plant startup times

A large amount of energy is spent when starting up a plant. The more quickly and efficiently a plant is started, the more energy is saved. For example, a power plant can achieve faster startup times by replacing the overspeed bolt trip system with a turbine protection system integrated with the DCS. After every shutdown, the power plant must test the turbine's trip system. An overspeed bolt trip system test requires the turbine shaft to spin at 110% synchronous speed. The turbine must first be warmed up for a few hours in order for the shaft to be thermally prepared to operate at 110% of synchronous speed. When the turbine protection system is integrated with the DCS, it is possible to test trips at nearly any turbine shaft speed by simply watching the solenoids activate without actually tripping the turbine. No time is spent thermally conditioning the turbine for trip testing; thus, startup times are lower compared to an overspeed bolt trip system. Removing the need for an overspeed trip bolt decreases startup time and increases the life of the turbine, as operating above the shaft design speed prematurely ages the turbine.

An integrated system allows for enhanced energy savings applications such as rotor stress prediction for steam turbines. The controller-based rotor stress application is now possible since all of the required inputs are available from the integrated system. Data from the various integrated components such as vibration, turbine position, and thermal couple inputs, in conjunction with process data, simplifies the design of the application. The rotor stress application produces turbine thermal stress information. If the turbine is started improperly, the shaft can warp. Typically, it takes nine to twelve weeks to straighten a warped turbine shaft. The goal of the application is to keep stress on the turbine shaft to a minimum while providing operators with acceleration and loading rates. With this information, operators can start the turbine more quickly. The faster the turbine is started, the more startup energy is saved, and more revenue is realized from the generation of power.

Make your operators smarter

With traditional multiple system plants, operators make critical decisions in silos. Often they have a myopic view of the plant, and their knowledge and skill set is limited to only one area. With an integrated system, operators can collaborate more effectively with other disciplines. They will have total plant visualization - operators can now see into the plant beyond their normal process areas. Their capabilities will expand beyond traditional roles and functions. A DCS process control operator must now understand the effects that substation automation systems have on the process control areas. Better visibility turns data into actionable knowledge that operators can use to support smart decisions, made more quickly. By utilizing the Electrical Integration architecture, operators get out of their silos and into saving money and increasing uptime throughout the plant.

Consider the following scenario. It is the job of a DCS operator to ensure that a mixer's agitator motor is turning and operating at the proper speed. From a DCS process control display, the operator can start, stop, and change the speed of the motor. Suddenly, the mixer stops. After repeated unsuccessful attempts to restart the motor, the operator is empowered to do nothing but to start calling maintenance engineers for help. With an integrated system, the operator is empowered to take action. Instead of just having access to the mixer's process

control display, the operator can now call up the substation's Single Line Diagram Display (SLD) and check the circuit breaker's status (Figure 9a). Next, the operator clicks on the motor's IED faceplate (Figure 9b) and views the disturbance recording that was automatically uploaded from the IED (Figure 9c). Information about the health of the IED and circuit breaker is available from the IED's asset monitor made available by a click on the faceplate. See Figure 9d. Another click on the faceplate calls up a remote configuration session with the IED. From here, the operator can dig deeper into the problem. Once the operator's analysis is complete, he or she can correct the problem or call the appropriate person to assist. Once the problem has been resolved, the operator can close the circuit breaker, switch back to the mixer display, and restart the motor. All steps have been completed in this example from a single operator station.



Figure 9a – Single line diagram of the substation

🎇 PMC4_A6 : Faceplate 💶 🗙						
PMC4_A6						
PMC4_Motor_Feeder						
Tun -		sf> 🖪				
Main Stat.	Interlocks	Alarms Sta				
Opened						
Closed						
Racked	Out					
Earthed						
📕 Open co	mmand					
Close command						
Interlock A						
Interlock B						
Number of operations 6						
Mode of Operation LOCAL CREMOTE						
Disturbance Recorder Remote Configuration						
	<u> </u>					

Figure 9b – Motor's IED faceplate



Figure 9c –Disturbance recording

🗑 REF615 Feeder Protection : ABB_REF615_AM 📃 🗖 🗙								
🔇 🕥 🥪 🗸 REF615 Feeder Protection: ABB_REF 🗾 🐉 🖉 🈓 🖅 🚽 📋 👻 🔍								
REF615 Feeder Protection - ABB_REF615_AM Asset Monitor								
Asset Monitor Status: good								
Severity	Condition	Sub Condition	Description	Timestamp				
750	Circuit Breaker Operation Time	Operation time exceeded	Indicates CB has not been operated for a long time	1/4/2010 12:35:25				
	Spring Charge Indication	Normal		1/4/2010 12:35:25				
	Breaker Wear	Normal		1/4/2010 12:35:25				
750	Breaker Contact Travel Time	Out of Specification	Time for the CB to close its contacts.	1/4/2010 12:35:25				
750	Number of Operation Cycles	Cycle High Limit Count	Number of times the CB has cycled.	1/4/2010 12:35:25				
	Accumulated Energy	Normal		1/4/2010 12:35:25				
	Gas Pressure Supervision	Normal		1/4/2010 12:35:25				
•				۱.				

Figure 9d –A feeder protection relay's asset monitor

Single plantwide sequence of events list

With a single plantwide system, troubleshooting plant upsets can be easier and faster. A common plantwide sequence of events (SoE) list is made available by the integrated system. This is possible because IEC 61850 uses Simple Network Time Protocol (SNTP) to synchronize all IEDs on the network. Time-stamped event resolution is 1ms with IEC 61850. No longer will process control and power engineers need to attempt to match up unsynchronized event lists from multiple systems. In the mixer example discussed previously, operators and engineers would be able to troubleshoot the plant disturbance more quickly with a common, synchronized, plantwide sequence of events list.

A single plantwide system has a smaller footprint. Less servers, switches, and other IT assets are needed. By using Ethernet, interconnection wiring is reduced or eliminated making a more simple, overall system design that is easier to build and maintain over the life cycle of the plant.

What's in it for the power engineer?

In the past, the electrical operator could not interlock the DCS operator without expensive schemes including complex software gateway or hard-wiring signals between the substation system and the DCS. For example, substations often use Modbus. Modbus has a master/slave communication scheme, while IEC61850's GOOSE messages are multicast. As a result, special logic is required when using Modbus to allow the power engineer to interlock the DCS operator. The special logic takes extra effort to implement and it makes future system changes more difficult and costly. It is more cost effective to use IEC 61850 to create DCS interlock schemes since its broadcast messaging eliminates the need for extra logic.

Single strategy for asset management

More advanced DCS systems are able to optimize plant assets beyond smart instruments with an integrated asset optimization system. Integrated process and power automation architecture allows plant electrical equipment health to be added to the process control system's asset optimization system providing a single view for all critical process and electrical plant assets. See Table 1 for a list of asset monitors for both process and electrical equipment. An asset monitor is a software component that promptly reports one or more health conditions of an asset. Maintenance planning becomes more efficient since we now have a single source of data for maintenance analysis. Less time is spent planning, leaving more time for actual maintenance work.

Process	Electrical				
Instrumentation	Transformers				
Rotating Equipment	LV Circuit Breakers				
Vibration	UMC 22 Motor				
	Starters				
DCS Controller Health	MNS iS LV				
	Switchgear				
IT Assets	Motors				
Heat Exchangers	Drives				
Control Loops	Protective Relays				
Other Process Plant	Other Electrical				
Equipment	Equipment				

Table 1 List of Asset Monitors

A centralized system provides operators, engineers, and maintenance personnel with relevant actionable data to prevent plant upsets and predict equipment failures. For example, advanced feeder protection relays can predict time remaining in a circuit breaker's life. This information is buffered locally in an RCB and is fed vertically into the asset optimization system via MMS and then read by asset monitors. A feeder protection relay's asset monitor is reporting a problem with the breaker contact travel time. Refer to Figure 9d. In this scenario, the circuit breaker is taking too long to open or close. The operator who is immediately alerted to the problem, reports it to the appropriate maintenance person. With a common user environment for operations and maintenance, operators and maintenance personnel can work together to troubleshoot problems more quickly and avoid plant upsets.

Demonstrated savings

Cost avoidance

Integrated process and power automation is all about saving time and money. The strategy can eliminate equipment that might otherwise need to be purchased such as remote panels, IT equipment, and control panels. Less equipment leads to simpler designs and smaller system footprints. It also reduces wiring.

Take for example, a substation system that has switchgear with 10 bays. The substation system must be linked with a DCS and a Power Management System (PMS). In general, approximately 70% of the communication signals to the substation's relays are typically hardwired. See Table 2. In this example, only the wires to and from the IEDs will be considered while the wires among other devices are not included in the calculations. There are 85 wires from the DCS to the substation system, 383 between the PMS and the substation system, and 104 inter-bay signal wires for a total of 572 wires. By using IEC 61850, the wires can be eliminated completely. Each wire has two terminations for a total of 1144 terminations. Using an average cost of \$115 per termination, the termination costs alone could be reduced by \$131,560. Other potential cost savings include less hardware and lower life cycle costs due to a simpler design.

	To/from IEDs	To/from other devices	Total
Inter-bay substation system signals	104	116	220
DCS	85	47	132
Power mgmt system & other external systems	383	252	635
TOTAL	572	415	987

Table 2 - Number of I/O wires

Petrobras succeeds with integration at the REPAR refinery

Petrobras is a major energy company based in Brazil with over 100 platforms, 16 refineries, and 6000 gas stations. They are faced with many challenges as they expand their Substation Automation infrastructure. See Figure 10. Petrobras needs to integrate new ABB substations with legacy power management systems. The PMS functionality and data need to be shared with both the new and legacy systems. At the same time, they are looking for better performance, reliability, and system information.



Figure 10 – Petrobras before integrated process and power automation

Petrobras needed a future proof technology with a simplified design that will allow for easy future expansion. They implemented ABB's integrated process and power architecture by using IEC 61850 technology at their REPAR refinery. The REPAR refinery is located approximately 400 km south of Sao Paolo. The solution provides a unique and open concept with one control library, one control system, and one common IEC 61850 engineering toolset. See Figure 11. With a common system, standardization on operational and maintenance procedures is easier.

The combination of the substation automation system with the System 800xA DCS has brought benefits to Petrobras in many areas including standardization, lower investment costs, integration of maintenance practices, simplification in project execution, and lower life cycle costs. When dealing with new and legacy systems, it is critical to have standardized procedures, settings, control logic, controller libraries, and operational and maintenance procedures.

Standardization is easier and practical with an integrated system compared to working with disparate systems and technologies. Petrobras has experienced lower investment costs with a combined system including 30% less man hours due to reuse of engineering data. Less

cabling is needed when implementing IEC 61850 technology with the DCS. Critical data is now shared between the DCS and the substation automation system via Ethernet instead of using hundreds of hard-wired signal cables. An integrated architecture creates a more simplified system. For example, Petrobras has a single tool set for engineering and device integration. This simplification in the overall system design equated to faster project execution, testing, and commissioning with a 25 to 30% reduction in overall project execution time. Petrobras is beginning to realize lower life cycle costs. Initially, Petrobras has reduced their training costs by 20%. Next, Petrobras is optimizing their maintenance through integration of maintenance practices among instrumentation, motors, power devices, and IT systems. Their goal is to reduce unscheduled downtime and increase availability through online monitoring of critical assets using both real-time and historical data. The data is made available remotely to centralized and outsourced maintenance centers.

Petrobras has a long term vision for energy efficiency, and it is part of the company's overall strategic plan. They realize energy efficiency is good for business financially and through an improved image with its customers, environmental groups, and society in general. Petrobras is looking for energy savings from improved visibility into power usage and equipment performance. The top areas of concern are motor systems, combined heat and power, steam systems, and energy recovery systems. There focus will be on integrated process and power automation systems, high performance drives, advanced controls, emission controls, and modernization of existing sites.

Long term operational costs will be minimized as the architecture provides a more reliable system with fewer assets, spare parts protocols, and wiring. Energy costs can more easily be managed and reduced with a unified system. With a common platform from ABB, Petrobras is experiencing lower maintenance and life cycle costs, capital cost savings, and efficient engineering by integrated project teams.



Figure 11 – Petrobras after integrated process and power automation

Conclusion

Integrated process and power automation architecture can improve plant uptime, increase energy efficiency, and lower life cycle costs for heavy users of electricity including power generation, oil and gas industries, chemical plants, and pulp and paper mills. Energy efficiency can be gained with integration with improved visibility into power consumption, integrated drives, and faster plant startups. Refineries and other major consumers of electricity are experiencing lower CAPEX with Electrical Integration. Silos can be broken among operators, engineers, and managers with an integrated system making more efficient endusers. It allows for quicker time to problem resolution with a centralized plant maintenance system. Plant upsets can be resolved more quickly with a plantwide sequence of events list. A smaller system footprint can reduce spare part inventories, lower training time for users, and make for a simpler overall system design with fewer wires, yet more connectivity. The use of Industrial Ethernets such as the IEC 61850 standard is being embraced globally as the enabler for integrated process and power automation architecture.

References

 Pipeline and Gas Journal, October 2009, "Integrated Power and Automation Systems: Future trends for pipeline system efficiency", Jeffrey Vasel
 "Future power plant control – Integrating process and substation automation into one system", Joerg Orth, ABB AG, Mannheim, Germany
 "Benefits of IEC 61850 Networking" presentation from UCA International Users Group, Ralph Mackiewicz, SISCO, Inc.
 Power magazine, Volume 153, No 2, February 2009, "Optimize your plant using the latest distributed control system technology", Ralph Porfilio
 <u>Energy efficient design of auxiliary systems in fossil-fuel power plants</u>, ABB Inc. in collaboration with Rocky Mountain Institute USA, December 2009

Keywords

DCS - Distributed Control System

- ECS Electrical Control System
- TCS Turbine Control System

IED – Intelligent Electrical Device

LV – Low Voltage

MV – Medium Voltage

- HV High Voltage
- SA Substation Automation

IEC 61850 - International Electrotechnical Commission's substation automation standard

ANSI - American National Standards Institute

PID - Proportional Integral Derivative Control Algorithm

HART – Highway Addressable Remote Transducer Protocol

AO – Asset Optimization

CMMS - Computerized Maintenance Management System

SOE – Sequence of Events

NERC - North American Electric Reliability Council

CIP - Critical Infrastructure Protection

LN – Logical Node

OPC - OLE for Process Control standard for soft interface over Ethernet

GOOSE - Generic Object Oriented Substation Event

MMS – Manufacture Messaging Specification

SLD – Single Line Diagram

SNTP – Simple Network Time Protocol

EMI – Electromagnetic Interference