CIGRE Australia APB5
SEAPAC 2013
Brisbane 12-13 March

Benefits of integrating real-time automation functions into IEC 61850-based SCADA platforms

Grid Automation

Name	Company	Email address
Mark Clemens	Ing. Punzenberger COPA-DATA GmbH	markc@copadata.com
Ursula Piela	Ing. Punzenberger COPA-DATA GmbH	ursulap@copadata.com
Pascal Schaub	QGC	pascal.schaub@bg-group.com

Keywords: SCADA Automation, Smart Grid, Load Shedding, GOOSE, MMS, IEC 61850, IEC 61131-3

Contents

1 Abstract 1
2 Introduction 2
3 Test System 3
3.1 Overview 3
3.2 Load Shedding PC 4
3.3 Relay PC 5
3.4 Analysis PC 5
3.5 Network Architecture 5
4 Method 6
4.1 GOOSE Trip Messaging 6
4.2 Test Scenario Control 6
4.3 GOOSE Message Capture and Analysis 6
4.4 Test Scenarios 7
5 Results 7
5.1 Load Shedding Performance 7
5.2 Single vs. Multiple GOOSE Messages 7
5.3 Test Result Graphs 8
6 Discussion 9
7 Conclusion 10
References 11
List of Figures 11
List of Tables 11
Biography: Mark Clemens 11
Biography: Ursula Piela 12
Biography: Pascal Schaub 12

1 Abstract

Proposed smart grids will use a digital platform for the automation of the power system. There is a requirement for substation automation systems to provide a higher degree of automation capability to ensure reliability of supply to the customer and deliver on the main objectives of a smart grid. The performance of current automation systems have to date been sufficient. However, new applications such as wide-area measurement and control, remedial action schemes and automatic load shedding and load restoration require more capable automation systems and the use of international standards to ensure interoperability between systems and vendors. Furthermore, these automation systems need to be robust,

secure and highly scalable in order to provide asset owners and operators with a flexible solution that allow for the operation of the power system infrastructure to the highest reliability and safety standards at an acceptable cost.

This paper investigates the capabilities of an IEC 61850 based SCADA solution that supports the integration of real-time automation functions into their platform based on the use of IEC 61131 logic programming and IEC 61850 as a means of communication for distributed automation functions. The performance of simple Centralised Remedial Action Scheme (CRAS) implemented on a SCADA system has been evaluated and compared to the legacy methods to determine if the performance, security, reliability, scalability/flexibility and cost are justified considering the additional complexity of an integrated system. Experimental results show that the system delivers significant benefits including improved system reliability through reduced device count, improved safety with configurable operator interfaces, mobility services and remote diagnostic capabilities, and reduced engineering costs by providing a unified engineering environment that allows simple and seamless configuration based on the use of open standards.

2 Introduction

The key planning and operational challenges electrical utilities are facing today are; congested transmission networks with limited expansion options, long lead-time for building electricity network infrastructure and the integration of new generators including renewables into the electricity networks with some uncertainty in the new generation siting and locations. The operating environment today is also experiencing increased voltage support and power quality requirements in an electricity market that is mandated by legislative and regulatory reliability and environmental targets with a strong emphasis on network reliability at a reduced overall cost. The grid needs to become smarter to meet those challenges moving forward.

The smart grid has been defined as an umbrella term for new technology solutions that are an alternative to the current architectures and designs used in power systems, with the following benefits: reliability, flexibility, efficiency and environmentally friendly operation [1]. Much of the smart grid focus has been in the distribution arena where distributed automation provides many benefits, but there is a need arising to introduce smart technologies into transmission networks to improve the ability to observe and control the power system as a whole, requiring interoperability between the different automation systems. The IEC and NIST have developed smart grid vision documents that identify the IEC 61850 series of standards to be key components of substation automation and protection for the transmission smart grid [2], [3]. The objective of the IEC 61850 series of substation automation (SA) standards is to provide a communication and systems standard that meets existing needs; while supporting future developments as technology improves. Ethernet is another key component and provides a means for connecting intelligent electronic devices (IEDs) with primary plant and for interconnection between IEDs within and across substations. Proposed smart grids will use a standards-based digital platform for the automation of the power system. These platforms will support the implementation of distributed measurement, protection and control functions and provide a high degree flexibility and scalability to accommodate the changing needs of the electricity networks.

Remedial Action Schemes (RAS) also known as special protection schemes or system integrity protection schemes are a distributed control function with the purpose to perform fast and automated control actions to ensure acceptable power system performance following critical outages on the electricity network by utilising Protection IEDs and fast telecommunication networks. RAS applications are typically considered when other operating and construction options are substantially more expensive or cannot be implemented in time to avoid problems identified in power system studies. They are normally deployed where generation is far from load centres due to the cost and challenges involved in building new transmission lines. There are two different types of RAS applications. The first type is the distributed RAS application with a Central Control System (CCS) arming the load shedding logic in dedicated Protection IEDs based on network contingencies, communicating via dedicated point-to-point links. The second type is the Centralised RAS (CRAS) where a CCS performs the load shedding function via dedicated Protection IEDs, communicating to the IEDs via multicast communication mechanism. CRAS applications are electricity network contingency-centric and much faster when compared to the network generation-centric RAS application. Historically, CRAS applications were identified as having a few major disadvantages. Many of the existing schemes are high in hardware costs with significant latencies throughout the system and availability issues. Most systems are from a single vendor, relying on proprietary communications with system degradation and scalability being a major challenge. Reliance on a single vendor also introduced the risk of product obsolescence and limited pathways for migration.

The main objective of the work presented in this paper was to investigate the capabilities of a Commercial off-the-shelve (COTS) SCADA software product running a time-critical CRAS application on the same platform used to perform the functions of substation HMI and protocol conversation used for remote monitoring and control of the substation via a Network Control Centre (NCC). The aim was to evaluate and compare the system to the legacy methods to determine if the performance, security, reliability, scalability/flexibility and cost are justified considering the additional complexity of an integrated system. The test system developed as part of this investigation had to be designed to allow automated testing of the CRAS application under different power system contingency scenarios.

The product selected for the test bed is the SCADA software package zenon from COPA-DATA, running on a Microsoft Windows based hardware platform. The CRAS application was to be implemented using the IEC 61131-3 standard for the programming of function block logic and the IEC 61850 GOOSE [4] as a means of communication between the Protection IEDs controlling the circuit breakers and the CRAS function.

Chapter 3 details the test system architecture and Chapter 4 describes the test methods. The results of this testing are given in Chapter 5, along with discussion of the significance in Chapter 6. Conclusions are presented in Chapter 7.

3 Test System

3.1 Overview

The system architecture shown in Figure 1 consists of two PC workstations with Windows 7 enterprise 64 Bit with one being used as the Load Shedding PC and the second as an Analysis PC. The PC workstations are members of a Windows Domain via a second network card, which can be used to authorize substation HMI users. The workstations have antivirus software installed and use Windows Server Update Services to detect required Windows Updates. The Relay PC is an embedded DSC10 Bay Control Unit (BCU) from Ducati Sistemi. The three test systems are connected through a managed Ethernet switch via CAT5e Ethernet cables (100 Mbit). The two PC workstations contain other software programs such as Microsoft Office, different versions of the zenon software using different versions of Microsoft SQL Server and also Microsoft Visual Studio 2012, all of which are not specifically required for the functionality of the test system. None of these software packages are believed to affect the results of this test in a positive or negative way that is measurable. The software is installed as a single installation that contains all the required components that can be configured using one integrated engineering environment, and activated as needed. The functions in the software allow a PC to assume the role of an HMI, Gateway, Ethernet network monitoring system or IED without additional hardware, allowing simulation of almost any test scenario. The specification of the different PCs used within the test system are summarised in Table 1

Table 1 - System specifications

System	OS	CPU	HMI	Other
Load Shedding PC	Windows 7 x64	Core2Duo E6400 2.13 GHz 2 GB RAM	zenon runtime Energy Edition 7.10 – 64 bit	
Analysis PC	Windows 7 x64	Core2Quad Q6600 2.40 GHz 8 GB RAM	zenon runtime Energy Edition 7.10 – 64 bit	Wireshark 1.8.5 – 64 bit zenon editor Energy Edition 7.10 – 64 bit
Relay PC	Windows CE 6.0	Atom 1.6 GHz 512 MB RAM	-	

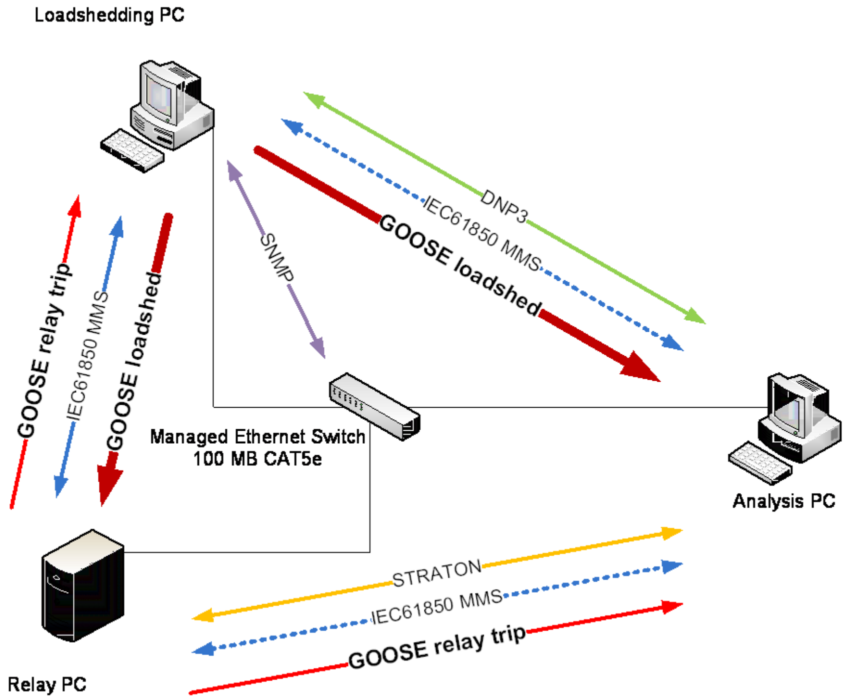

Figure 1 - Test setup

3.2 Load Shedding PC

The Load Shedding PC is called this way in the test setup, as it performs the load shedding functionality as one of its tasks being the focus of this paper. The load shedding functionality is an integrated, yet standalone part of the HMI on this system, that can be simply configured and armed or enabled when required. The load shedding functionality is integrated in an IEC 61131 zenon Logic instance with IEC 61850 GOOSE Subscriber, GOOSE Publisher and MMS Server.

The purpose of the load shedding function on this PC is to monitor GOOSE trip messages from protection relays, and publish further GOOSE messages for the appropriate relays to trip the circuit breakers and shed load connected to the electricity grid. Once a GOOSE trip message is received from a relay by the load shedding zenon Logic, the zenon Logic calculates which loads are required to be shed according to a predefined load shedding matrix, and immediately after calculation sends out GOOSE messages to other relays in the network, for circuit breakers to trip and shed their corresponding loads in an attempt to safeguard the overall power system stability and reduce the total downtime.

The logic that determines which loads to shed for the purpose of the simulation is a matrix programmed in Structured Text (ST) being one of the five programming languages in IEC 61131-3, and can accept parameters from the local HMI, or also from a remote controlling station through a number of different protocols, like IEC 61850, DNP3, IEC 60870, OPC UA, Modbus, or the native STRATON protocol. The zenon Logic program is C compiled using the Visual Studio 2012 C compiler and has a configured target cycle time of 3 ms.

To cater for different test scenarios, the IEC 61850 data model in the server of the load shedding logic is configured with twenty logical devices each with twenty PTRC logical nodes, with a total of 400 GOOSE control blocks. Different sizes of datasets used at the GOOSE control blocks, ranging from one Op data object to 20 Op data objects. This configuration allows for a large range of possible test scenarios, in order to examine the performance of the GOOSE load shedding messages under different load conditions. The GOOSE control blocks in the load shedding logic are configured with VLAN ID 1 and the 802.1p priority five, to ensure priority treatment of the GOOSE network traffic over the regular network traffic. The HMI running on the Load Shedding PC performs the classical role of generating events and alarms, issues commands and stores data in a local historian for reporting and trending. Communication to the IEDs takes place via IEC 61850 MMS using Buffered and Unbuffered Reports. The Ethernet switch is monitored via SNMP through 24 OIDs and a process gateway function provides 320 analogue values and 20 binary values collected from the Relay PC using IEC 61850 MMS via DNP3 to a remote control centre, which is simulated as a DNP3 master on the Analysis PC. IEC 61850 file transfer is executed every two seconds to get a file from the Relay PC. The role of the HMI in the test setup is to generate network traffic normally occurring in a substation network, and to generate the load of a typical HMI on the Load shedding PC, to assess the impact on the performance of the Load shedding function.

3.3 Relay PC

The Relay PC runs IEC 61131 zenon Logic with IEC 61850 MMS Server GOOSE Publisher instances on Windows CE 6.0. Twenty protection IEDs in twenty Logical Devices are configured in the object model, each with two instances of PTRC, one instance of CSWI and one instance of MMXU, representing the circuit breaker bay. Buffered Reports are configured for each logical device for CSWI1 and Unbuffered Reports are configured for each Logical Device for MMXU1. GOOSE messages are published for all 20 relays, using a dataset that contains two instances of PTRC with both the Tr and the Op data object. The GOOSE Control Blocks in the Relay PC logic are configured with VLAN ID 1 and the priority five, to ensure priority treatment of the GOOSE network traffic over the regular network traffic. Sixteen data object values for the analogues in MMXU and the trips for the relays are simulated in the zenon Logic program. The Relay PC has an inbound MMS Client connection from the Load shedding PC (HMI) and an inbound MMS Client connection from the Analysis PC.

3.4 Analysis PC

The Analysis' PC primary function is to capture the network traffic for the GOOSE messages sent by the Relay PC and the Load shedding PC, using Wireshark version 1.8.5. The Wireshark capture file is later used for measuring the response times from the Load shedding PC after a circuit breaker trip.

Running as a secondary function on the Analysis PC, is a HMI with a DNP3 Master to get data from the DNP3 gateway on the Load shedding PC, to simulate a DNP3 connection from the Load shedding PC to a Network Control Centre (NCC). The values received from the DNP3 process gateway are stored in a historian configured in the HMI.

Also running on the Analysis PC is IEC 61131 zenon Logic with an IEC 61850 MMS Server as GOOSE Subscriber for GOOSE messages from both the Load Shedding PC and the Relay PC. Inside the logic the received GOOSE messages are processed and the time is calculated between the receipt of the first GOOSE relay trip message from the Relay PC and the receipt of the GOOSE load shed messages from the Load Shedding PC. For each test scenario the time differences are calculated and stored in an array variable, which in turn are saved in the historian of the HMI. This calculation is performed to verify the results measured with Wireshark. The zenon Logic program is written in ST, is C compiled using the Visual Studio 2012 C compiler and has a target cycle time set of 3 ms.

In an additional IEC 61131 zenon Logic instance on the Analysis PC with an IEC 61850 MMS Client, the logic disables and enables the GOOSE Control Blocks on the Relay PC and the Loads Shedding PC for each relay asynchronously, to facilitate a more even distribution of GOOSE retransmission messages for this test scenario. While GOOSE retransmission messages would not normally occur all at the exact same time, as they come from different devices, without the de-synchronisation of the GOOSE messages using this zenon Logic, exactly this would happen.

The local HMI on the Analysis PC also has a connection over Ethernet using the STRATONNG driver to the zenon Logic on the Relay PC, to drive the different test scenarios in the Relay PC used in this test architecture. Also located on the Analysis PC is the zenon Energy Edition Editor, which is the development environment for the two zenon runtime HMI projects and all of the four zenon Logic projects.

3.5 Network Architecture

The managed Ethernet switch is configured in VLAN unaware mode. This allows 802.1Q tagged packages to be passed through unmodified also when the VLAN ID is 0 (Priority tagged messages). In this test a VLAN ID "1" was set for the GOOSE messages. All ports are configured as Edge ports. No link aggregation or Spanning Tree is used as only one switch is used in this test setup and all devices are connected through a single Ethernet link. The 802.1p priority five used for the GOOSE messages in the test setup is linked to the priority queue "High" in the switch. No static MAC address table is configured to specify a CoS for a specific source or destination. SNMP is enabled to allow monitoring of the switch ports. Port security was not used in the test architecture.

4 Method

4.1 GOOSE Trip Messaging

Due to the nature of the test setup with one zenon Logic instance on the Relay PC, GOOSE messages generated for relay trips are published nearly simultaneously by the different IEDs. The Load Shedding PC in the test setup will receive multiple relay trip GOOSE messages only 300 μs apart and therefore multiple relay trip messages will be processed in the same load shedding calculation cycle. This also means that the load shedding logic needs to generate GOOSE load shedding messages for all received relay trip GOOSE messages in the same cycle, a worst case scenario for a load shedding logic.

In reality, IEDs, although time synchronized, will still respond at slightly different times, due to offset differences in the internal cycle time and differences in the evaluation of the measured values and therefore GOOSE messages would arrive at the load shedding logic within an interval range of several milliseconds, leaving the load shedding logic more cycles to process the load shedding calculation, and more cycles for the subsequent generation of GOOSE load shedding logic messages. Also the occurrence of a power system fault that will initiate trips by more than one relay at the exact same time is considered as unlikely.

Each GOOSE Control Block in the Relay PC logic and the load shed logic has a unique APPID. This allows for easy filtering in Wireshark as the APPID of the GOOSE relay trip messages and the APPID of the GOOSE load shed messages for each scenario is known from the SCL file. Also the order in which the GOOSE load shed messages are generated is known and is identical for each sample in the scenario. It is therefore possible to determine the first and the last GOOSE load shed message in Wireshark based on the GOOSE APPID.

4.2 Test Scenario Control

The zenon Logic on the Relay PC provides configurable scenarios and sample sizes. From the HMI on the Analysis PC, the different scenarios are configured and the sample size is defined by parameterizing values in variables of the zenon Logic on the Relay PC over Ethernet via the native STRATONNG connection to the zenon Logic. Also the Analysis PC initiates the start of the set of samples for the test scenario.

4.3 GOOSE Message Capture and Analysis

On the Analysis PC, Wireshark is started to capture the network traffic including the GOOSE relay trip messages and the GOOSE load shed messages as a response. For each set of samples and for each scenario a .pcap file is created.

The Wireshark .pcap capture file is opened and the display filter option is applied on the "goose.appid" to ensure only the captured the GOOSE relay trip messages and the GOOSE load shed response messages are displayed for the 1000 samples, and an additional filter is set to goose.sqNum == 0, to ensure no GOOSE retransmissions are included in the result. The column for the time difference between the previously displayed packets is added. A verification of the received packets after applying the display filter, according to the test scenario and sample size, is performed and the display filter is modified to display only the first received GOOSE relay trip message, and the last received GOOSE load shed message. Finally, the displayed packets are exported as .csv for further analysis in Microsoft Excel.

In Excel the .csv exported packets are imported and using the auto filter feature, only the rows with the replies (GOOSE load shed) are displayed. The values in the column with the time difference, between the first GOOSE relay trip and the last GOOSE relay load shed are multiplied by 1000, and a scatter chart is generated for the 1000 samples. The filtered data rounded to the millisecond is the basis for the distribution chart where for the 1000 samples the occurrence of each number is established.

4.4 Test Scenarios

4.4.1 Test Scenario 1 – Two Trips, max. 32 Relay Operate – Single GOOSE

In test scenario 1, for each sample the Relay PC sends two relay trip GOOSE messages, 300 µs apart. The Load Shedding PC responds with sixteen load shed GOOSE messages for each relay trip message received. The dataset used for the load shed GOOSE Control Block in this scenario contains one data object "Op" from PTRC. A sample size of 1000 is used.

4.4.2 Test Scenario 2 – Two Trips, max. 64 Relay Operate – Single GOOSE

In test scenario 2, for each sample the Relay PC sends two relay trip GOOSE messages, 300 µs apart. The Load Shedding PC responds with 32 load shed GOOSE messages for each relay trip message received. The dataset used for the load shed GOOSE Control Block in this scenario contains one data object "Op" from PTRC. A sample size of 1000 is used.

4.4.3 Test Scenario 3 – Two Trips, max. 40 Relay Operate – Combined GOOSE

In test scenario 3, for each sample the Relay PC sends two relay trip GOOSE messages, 300 µs apart. The Load Shedding PC responds with two load shed GOOSE messages for each relay trip message received. The dataset used for the load shed GOOSE Control Block in this scenario contains ten data objects "Op" from PTRC. A sample size of 1000 is used.

4.4.4 Test Scenario 4 – Two Trips, max. 80 Relay Operate – Combined GOOSE

In test scenario 4, for each sample the Relay PC sends two relay trip GOOSE messages, 300 µs apart. The Load Shedding PC responds with two load shed GOOSE messages for each relay trip message received. The dataset used for the load shed GOOSE Control Block in this scenario contains twenty data objects "Op" from PTRC. A sample size of 1000 is used.

4.4.5 Test Scenario 5 – Single Trip, max. 32 Relay Operate, Single GOOSE

Test scenario 5 is similar to test scenario 1, but only a single relay trip is generated simultaneously for each sample, what may be a more praxis related scenario. The Load Shedding PC responds with 32 load shed GOOSE messages. The dataset used for the load shed GOOSE Control Block in this scenario contains one data object "Op" from PTRC. A sample size of 1000 is used.

4.4.6 Test Scenario 6 – Single Trip, max. 40 Relay Operate, Combined GOOSE

Test scenario 6 is similar to test scenario 4, but like test scenario 5, only a single relay trip triggers the load shedding. The Load Shedding PC responds with 2 load shed GOOSE messages. The dataset used for the load shed GOOSE Control Block in this scenario contains twenty data objects from PTRC. A sample size of 1000 is used.

5 Results

5.1 Load Shedding Performance

Once the GOOSE relay trip message is received and processed by the load shedding logic, multiple GOOSE load shed messages that are published, are 100 µs apart. Publishing sixteen single GOOSE messages as a response to one GOOSE relay trip message is performed within 1800 µs. The GOOSE load shed messages that are published for a second received GOOSE relay trip message in the same cycle follows without further delay. When for example for the second GOOSE relay trip message also sixteen single GOOSE load shed messages are published, the total time span from publishing the first GOOSE load shed message to the last (32) load shed message covers less than four milliseconds.

5.2 Single vs. Multiple GOOSE Messages

The test results clearly show a better performance when a GOOSE message contains multiple data objects compared to sending single GOOSE messages with one data object each.

In test scenario 4 using a combined GOOSE message a maximum of 80 load shed relay operate processed with an average time of 8.4 ms.

In test scenario 2 using 64 single GOOSE messages with one data object each, the average time is 13.9 ms.

5.3 Test Result Graphs

The graphs below show the results of the test scenarios described in chapter 3. The scatter chart shows the time difference in milliseconds between the first relay trip GOOSE message and the last GOOSE load shed message on the y-axis and the 1000 samples on the x-axis. The distribution chart shows the occurrence of the time difference rounded to the millisecond for the total of 1000 samples.

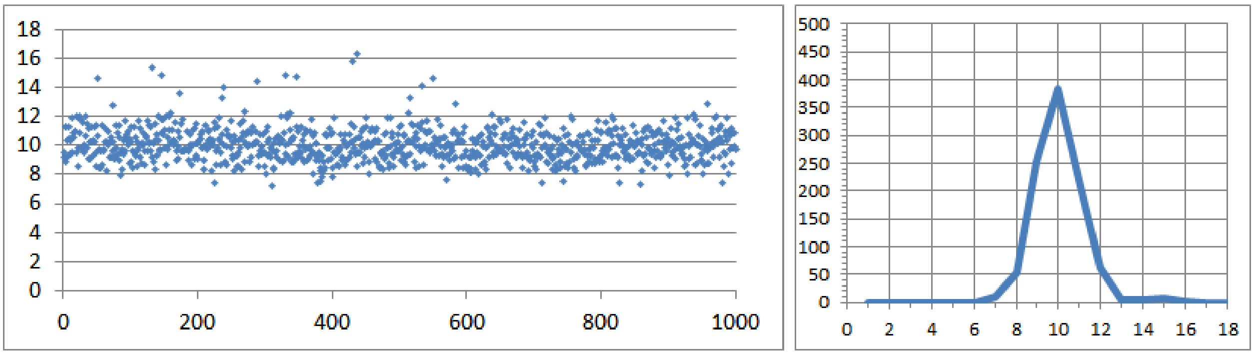

Figure 2 - scenario 1 - two trip, max. 32 relay operate – single GOOSE

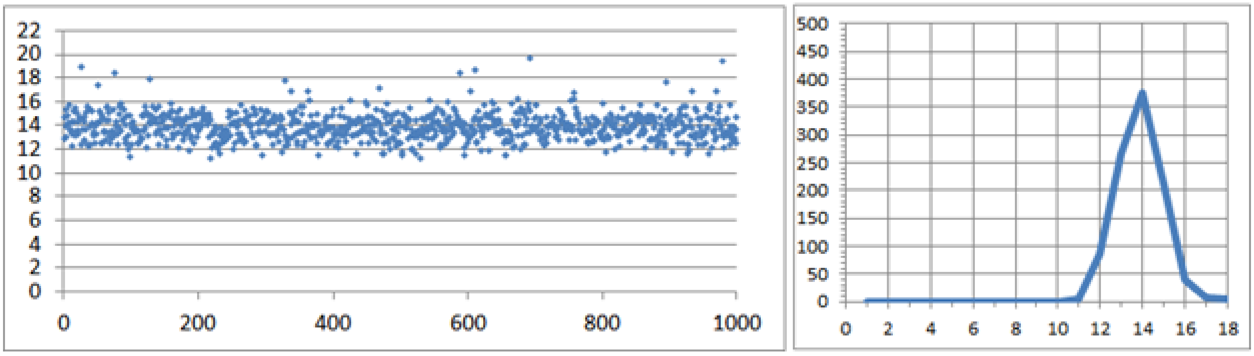

Figure 3 - Scenario 2 – two trip, max. 64 relay operate – single GOOSE

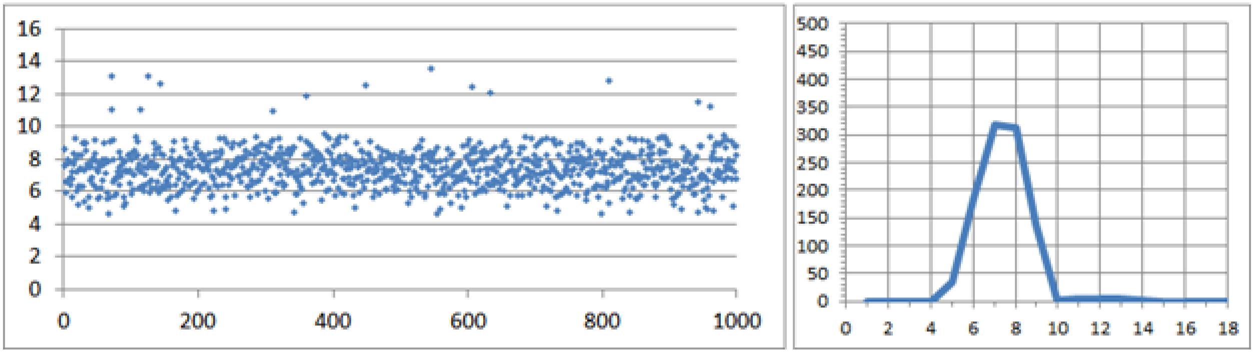

Figure 4 - Scenario 3 - two trip, max. 40 relay operate – combined GOOSE

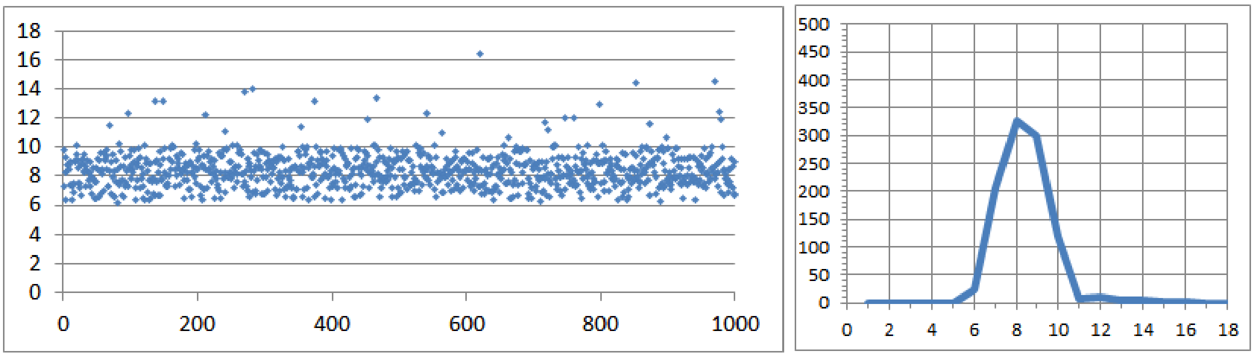

Figure 5 - Scenario 4 - two trip, max. 80 relay operate – combined GOOSE

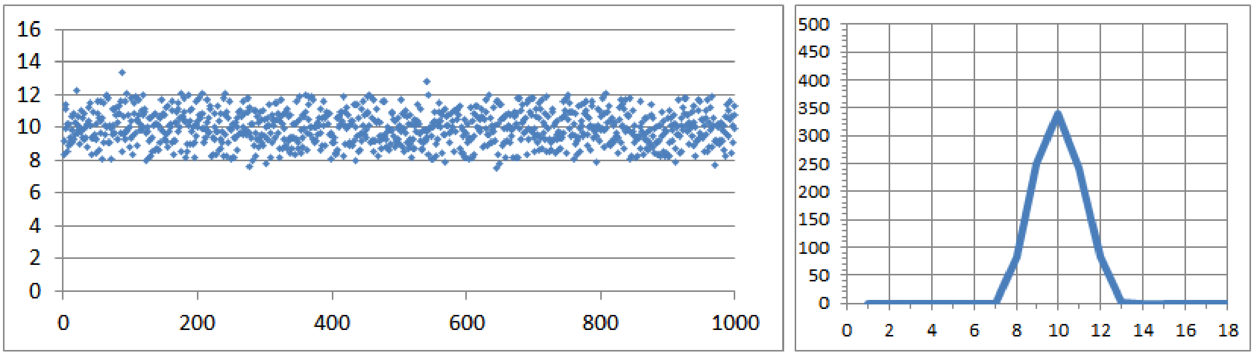

Figure 6 - Scenario 5 - single trip, max. 32 relay operate, single GOOSE

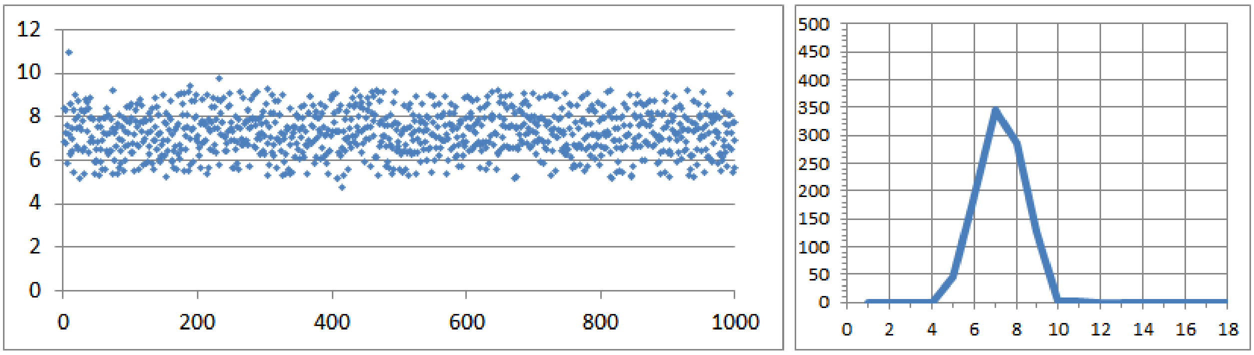

Figure 7 - scenario 6 – single trip, max. 40 relay operate, combined GOOSE

6 Discussion

The quantitative and qualitative analysis of the GOOSE timing results show that the performance of the CRAS function is comparable to legacy hard-wired systems and in some instances outperforms existing solutions. The Load Shedding PC reacts to a network contingency in under one power system cycle (20 ms on a 50 Hz electricity network) from the instance the Protection IED has signalled a power system fault via GOOSE message to the IED receiving GOOSE trip command to open its circuit breaker. The test scenarios were based on the assumptions that GOOSE Class P2 Type 1A are being used which specify a maximum transfer time of 3 ms between function output to function input. Hard-wired systems require a transfer time of at least 3-7 ms to achieve the same result and most existing CRAS schemes have task cycle times higher than 10ms to calculate the load shedding scenario with some schemes calculating the output conditions in sequential order. The additional functions of substation HMI and SCADA gateway installed on the Load Shedding PC had no measurable impact on the performance of the CRAS application.

The SCADA system evaluated has a distinct set of benefits in relation to security and personal safety when compared to conventional systems. Providing built in security features such as access control ensures that only an authorised person can perform work on the system or change the configuration. Built-in version control allows detailed tracking of who made which changes to the configuration at which time. The 61131-3 zenon Logic workbench offers an API that allows generation of the load shedding logic including all the necessary tags, from an external source, further reducing the room for error, and saving time and costs when similar CRAS functions need to be deployed at different substations based on a single configuration management base. Operator interfaces are highly configurable and provide the operator and support staff not only with an accurate history of all the operations performed on the system but also valuable information on the status of the entire system and all its components including the communication network. The connections between the IEDs and the Load Shedding PC have a built in wire-check for the GOOSE messages, alarming a loss of GOOSE publisher, a feature that is not typically supported in hard-wired systems. Also operators have the ability to tag components of the system that are taken out of service or put them into a test mode if required, avoiding operator error and preventing alarm flooding.

The integration of multiple functions into one system is reducing device count and therefore increasing the overall system reliability. Furthermore the CRAS function can be added at any time later after the original HMI system has been commissioned. The product evaluated supports redundancy in a hot-hot or hot-standby arrangement, ensuring that the system can meet availability requirements and avoiding a single-point of failure scenario. The availability of the CRAS scheme was further improved by removing the communication latency bottlenecks and having built-in diagnostic capabilities, providing an on-line diagnostic mode for the load shedding logic and remote access capability.

The benefits of scalability and flexibility were achieved by using an architecture option that supports open standards. The use of IEC 61850 and IEC 61131-3 ensures a high degree of interoperability, enabling the integration of other vendor's products and engineering tools. COPA-DATA's zenon product is running on standard Windows-based hardware and supports virtualisation. This allows a high degree of hardware independence, reduces maintenance, and provides the option to allocate more resources without hardware change, as the configuration and resource requirements change. New functions can easily be added to the existing architecture, removing the need to make changes on the IED level and new data sources can be integrated quickly into the system. New and more complex requirements such as the processing of synchrophasor measurements in the RAS can easily be added to the digital platform.

The solution investigated is utilising the same infrastructure used to perform the standard control and protection function of a substation. The reduction of components used by integrating the CRAS application into the existing solution architecture is resulting in reduced costs for hardware and software when compared to a conventional system where the RAS schemes typically require dedicated hardware. The use of IEC 61131-3 allows for the engineering logic to be implemented in different standardised languages. The integrated engineering environment provided by COPA-DATA saved time consuming data conversion between different engineering tools and allowed for a standards-based engineering approach to develop the test system and to auto-generate the electronic documentation. The use of IEC 61850 and Ethernet are key stones for the implementation of automated testing. Automated testing and automated regression testing saves much time and can greatly enhance the test coverage for a solution, resulting in cost savings and improved quality. Digital systems like the one presented in this paper offer remote access and diagnostic capabilities to fault find and rectify in service issues from a remote or office-based location. This not only results in significant cost savings but also improves personal safety removing the need for field staff having to be deployed to site 24/7.

7 Conclusion

The results presented in this paper have demonstrated the performance criteria for a CRAS application integrated into a substation SCADA system can be met with Microsoft Windows based off-the-shelf SCADA software that supports the integration of time-critical automation functions based on IEC 61850 and IEC 61131.

It has been demonstrated that new and more capable automation system products will improve the ability to observe and control the power system having a positive impact on the reliability and safety of the electricity networks. New digital platforms can support function integration, provide automated testing and remote diagnostics features, allow virtualisation and when combined with the use of an integrated engineering environment have the potential to significantly reduce cost of engineering, construction, operation and maintenance. Standards-based and hardware independent automation systems are highly portable, scalable and flexible.

Gaining an understanding of the capabilities of today's real-time automation products and IEC 61850, along with new distributed automation and control functions will provide decision makers with the confidence to adopt more capable digital platforms and implement a smarter grid.

The additional complexity introduced with those highly integrated systems is justified. However, digital technology products will require organisations to develop specialised skills-sets, work processes and procedures to ensure a successful transition to new solutions and architectures. Cyber security is a new emerging issue that needs to be when implementing digital systems.

References

List any references here

1. ISGTE Europe, 2010, Gothenburg, Sweden, 2010, Smart grid technology review within the transmission and distribution sector, V. Hamidi, K.S. Smith, and R.C. Wilson
2. SMB Smart Grid Strategic Group. (2010, Jun.) Smart grid standardization roadmap. IEC. [Online]. Available: http: //www.iec.ch/smartgrid/downloads/sg3_roadmap.pdf
3. Office of the National Coordinator for Smart Grid Interoperability, "NIST framework and roadmap for smart grid interoperability standards," National Institute of Standards and Technology, Gaithersburg, MD, USA, Tech. Rep. NIST SP 1108, Jan. 2010. [Online]. Available: http://www.nist.gov/public_affairs/ releases/upload/smartgrid_interoperability_final.pdf
4. Communication networks and systems in substations–Part 8-1:Specific communication service mapping (SCSM) – Mappings to MMS (ISO 9506-1 and ISO 9506-2) and to ISO/IEC 8802-3, IEC 61850-8- 1:2004(E), May 2004.

List of Figures

FIGURE 1 - TEST SETUP 4
FIGURE 2 - SCENARIO 1 - TWO TRIP, MAX. 32 RELAY OPERATE – SINGLE GOOSE 8
FIGURE 3 - SCENARIO 2 – TWO TRIP, MAX. 64 RELAY OPERATE – SINGLE GOOSE 8
FIGURE 4 - SCENARIO 3 - TWO TRIP, MAX. 40 RELAY OPERATE – COMBINED GOOSE 8
FIGURE 5 - SCENARIO 4 - TWO TRIP, MAX. 80 RELAY OPERATE – COMBINED GOOSE 9
FIGURE 6 - SCENARIO 5 - SINGLE TRIP, MAX. 32 RELAY OPERATE, SINGLE GOOSE 9
FIGURE 7 - SCENARIO 6 – SINGLE TRIP, MAX. 40 RELAY OPERATE, COMBINED GOOSE 9

List of Tables

TABLE 1 - SYSTEM SPECIFICATIONS 3

Biography: Mark Clemens

Mark Clemens finished his education in Automation Electronics at the ROC Leiden in the Netherlands. After moving to Austria in 2002 he started working as a technical consultant at the headquarters of Ing. Punzenberger COPA-DATA GmbH, a European HMI SCADA software manufacturer with more than 25 years in business.

He is now a Senior Consultant experienced with the use of SCADA software in many different industries, including Energy & Infrastructure, Food & Beverage, Pharmaceutical and Automotive. His special focus is on DNP3, ICS / SCADA Security, and ISA 88 Batch control.

Biography: Ursula Piela

Ursula Piela graduated (M.Sc., eng.) in computer science at the Faculty of Electronics on the University of Technology in Wroclaw, Poland in 1990.

She is now a Senior Consultant at the headquarters of Ing. Punzenberger COPA-DATA GmbH. Her special focus is on IEC 61850, IEC 60870 and product modules for the Energy & Infrastructure industry.

Biography: Pascal Schaub

Pascal Schaub received the B.Sc. degree in computer science from the University of Applied Sciences and Arts North-western Switzerland in 1995.

He is currently the Principal Process Control Engineer at Queensland Gas Company (QGC), providing the organisation with engineering expertise in process control and power management systems, high voltage protection and control systems and data networks. He has previous experience in the Queensland electricity industry, working for Powerlink Queensland as Principal Consultant Power System Automation; developing IEC 61850 based substation automation systems. Pascal is the director of D.T. Partners Pty Ltd, a specialist provider of product and consultancy services in the substation and grid automation domain. D.T. Partners is the distributor of the COPA-DATA product in the Australian and New Zealand energy markets.

Pascal is a member of Standards Australia working group EL-050 "Power System Control and Communications" and a member of the international working group IEC/TC57 WG10 "Power System IED Communication and Associated Data Models".