IEC 61850 GOOSE and IEEE C37.118 Synchrophasors Used for Wide-Area Monitoring and Control, SPS, RAS, and Load and Generation Management

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1 INTRODUCTION

While special protection schemes (SPS) often shed load, recent sophisticated remedial action schemes (RAS) reduce or terminate generation output during an emergency condition. Under certain load conditions, generation newly added to a previously balanced transmission grid will create system conditions that violate accepted reliability criteria.

At Southern California Edison (SCE), RAS systems are implemented to ensure reliable power system performance following outages on a transmission grid network. They include fast, automatic control actions to mitigate thermal overloads and system instability upon the loss of one or more transmission lines. With these automatic protection features, RAS systems are used in place of expensive alternative measures, which include reconductoring transmission lines, building new lines, and/or adding new transformers. Testing at SCE demonstrates the successful use of the IEC 61850 Communications Standard GOOSE messages over a distance of up to 720 km to collect synchrophasor data and transfer status and control indications. Complete detection, alarming, calculation, and remediation happens in well under the 50-millisecond benchmark.

Using standardized IEC 61850 GOOSE methods avoids the customization required to implement individual local RAS communications systems, allows centralized coordination of arming, disarming, and system testing, and simplifies coordinating system maintenance. Reliability improves with capabilities to monitor end-to-end grid parameters and quickly respond to abnormal conditions.

These methods of mitigation are intended to be used throughout the utility's area of operation as well as at all interties to neighboring utilities to facilitate dynamic load shedding/generation tripping and improved load management.

SPS and RAS must be put in place to protect existing systems that are called upon to serve new generation and load that are intertied with weak systems or that have geographical characteristics that reduce stability. Once protected, the automatic load and generation control assure stability while improving production and reliability. Once these are in place, wide-area monitoring and control are safely added to replace state estimation with real-time state measurement and management.

The results of this installation, performance testing, decision analysis, and acceptance criteria will educate potential users about the performance and utility of IEC 61850 GOOSE and IEEE C37.118 methods.

2 SPS USING RSRP PROTOCOL

The recently constructed Blythe Energy Power Plant (BEPP), located in Blythe, California, was designed to incorporate a gas-fired combined-cycle configuration consisting of two 175 MW combustion turbine generators and one 170 MW steam turbine generator. The 520 MW electrical output is connected to the region's transmission grid via the existing transmission system managed by the Western Area Power Administration (Western). Reference [1] describes the successful use of Robust Serial RAS Protocol (RSRP) communications within the in-service system. RSRP refers to the MIRRORED BITS® communications protocol, which is a serial peer-to-peer communications technology that exchanges the status of Boolean and analog data, encoded in a digital message, from one device to another. This inexpensive, highly secure technology is used in numerous protection, control, automation, and monitoring applications within BEPP, SCE, and around the world.

Impacts to existing power systems, typically caused by adding new generation to the established transmission grid, often include overloaded transmission lines, transformers, circuit breakers, and other system components that may cause violations of accepted reliability criteria. The North American Reliability Corporation (NERC), Western Electric Coordinating Council (WECC), and local reliability requirements determine the criteria for California installations, including the Blythe substation. To mitigate potential reliability problems, Western deployed a RAS system prior to connecting BEPP to the transmission grid. This RAS system provided generation reduction capabilities during transmission line overload conditions. Recognizing the increasing importance of having reliable RAS systems, Western chose to implement this system in a dual-primary design so that no single device or connection would be a single point of failure. Reference [1] discusses the design and implementation of these RAS systems using protective relays, communications processors, digital I/O modules, and an I/O processor.

3 COMPARING CENTRALIZED RAS SYSTEMS USING RSRP PROTOCOL AND IEC 61850 GOOSE

SCE documented a case study comparing the performance of multiple communications technologies and architectures available via protection and automation intelligent electronic devices (IEDs) for use in monitoring and controlling RAS. The discussion includes the design description and implementation issues of several popular and standardized technologies available today to perform high-speed digital data communications among IEDs. Reference [2] describes analysis of the serial and Ethernet methods for transferring RSRP and IEC 61850 GOOSE messages.

3.1 SCE's Reasons for a New RAS Approach

SCE deploys local RAS systems throughout their transmission operating area, including 1,183 miles of 500 kV lines, 1,181 miles of 230 kV lines, and 350 miles of 115 kV lines. Supporting these main transmission corridors are several independent localized RAS systems with more systems under development and the potential to add a multitude of new systems based on recent generator queue studies. Perhaps most importantly is the anticipation of creating RAS systems that cover very large areas. These newer systems will need to not only accept many messages simultaneously from many remote locations but also process each message and then the associated RAS logic.

System reliability is expected to improve with capabilities to monitor end-to-end grid parameters and quickly respond to abnormal conditions. The area of mitigation will expand from a few local choices to all nodes included within SCE's system, including dynamic load shedding/generation tripping and improved load restoration management. A new centralized RAS (CRAS) system will mirror the success of the localized systems to a wide-area RAS that covers SCE's large service territory.

3.2 Design for Reliability and Decision Analysis Predict System Availability and Value

Functionally, IEDs networked together into a substation automation system (SAS) provide operational SCADA data, engineering and analysis access, and high-speed interdevice data exchange. Reference [3] identifies the major selection and design criteria of network functionality, components, and topology. It examines and compares serial and Ethernet architectures for an example substation using the following criteria: reliability, cost of equipment and commissioning, safety, ease and cost to design, implement, maintain, and expand, effective data transfer rates, and performance of high-speed control signals.

IEC 61850-3 Section 4 also describes that each system shall be designed as a "fail-safe design" such that:

> *"…There shall be no single failure mode that causes the SAS to initiate an undesired control action, such as tripping or closing a circuit breaker. In addition, SAS failures shall not disable any available local metering and local control functions at the substation."*

IEC 61850-3 Section 4 describes the following reliability measures for design comparison [3]:

- Reliability measured as MTBF
- Device availability measured as percent availability
- System availability measured as percent availability
- Device maintainability measured as MTTR
- System maintainability measured as MTTR

4 SCE RAS MESSAGE PERFORMANCE ANALYSIS [2]

4.1 Speed and Control Timing

SCE established a benchmark of 50 ms to detect and respond with RAS control actions in the three-IED scenarios. This time includes remote detection of an abnormal condition, transmitting an alarm 460 miles over a WAN to the centralized RAS controller, determining the proper actions, and then transmitting these actions 460 miles over a WAN to the appropriate remote RAS IEDs where the control actions are implemented.

4.2 Test Description

The test involves three IEDs communicating to each other. IED1, the Monitor IED, is monitoring line conditions and, when appropriate, after a line-open condition is detected, sends a Status message to IED2, the Central Logic Processor IED. The status of the RAS, armed or disarmed, is resident in IED2 as is the logic to determine when to send a mitigation signal. The line-open condition is simulated by energizing an input contact on IED1. Upon receipt of the Status message from IED1, IED2 extracts its content and, if the RAS is armed, performs a calculation to determine if remedial action is necessary. If IED2 decides to take action, IED2 sends a Mitigation command message to IED3, the Mitigation IED. When IED3 receives the Mitigation command message from IED2, IED3 energizes a trip output contact. This output contact is hardwired to an input on IED1. In this way, the total time duration is measured between detection of line one open as a contact input on IED1 and the eventual trip output of IED3 detected as a second contact input on IED1. The time duration is measured with a separate instrument and verified with internal sequential events records (SER).

SCE staged the test with IEDs from two different vendors, identified here as Vendor A and Vendor B, and tested three different protocols. These tests were completed on a LAN (all IEDs directly connected peer-to-peer or via a local Ethernet switch) and across a WAN connection via a local Ethernet switch and Ethernet router.

GOOSE protocol messages were sent using a multicast group address and were, therefore, not routable over a WAN. In order to simulate WAN timing for the tests, SCE actually created a long LAN connection over the physical WAN connection, via the SONET system, between Los Angeles and Bakersfield, California. SCE recognized that, unlike the RSRP, the GOOSE protocol installations required logical LAN connections between all RAS locations. This raised severe security concerns that needed to be addressed separately.

4.3 Test Results

Table 1 shows the timing results of the tests performed. LAN and WAN peer-to-peer times were calculated based on SER records in the IEDs. All roundtrip time results for the "Three-IED Test Scenario" were measured externally using a scope except for one. The EIA-232 MUX Module vendor calculated a conservative worst-case 4 ms peer-to-peer delay and an 8 ms three-IED test delay using latency for the speed of light of around 5 μs per mile. These calculated results are consistent with actual observed performance.

Test Case	IED Peer-to-Peer	Three-IED Test Scenario
Vendor A GOOSE Protocol via Ethernet LAN	4 ms	13.3 ms
Vendor A GOOSE Protocol via Ethernet-to-WAN	9 ms	22.9 ms
Vendor B GOOSE Protocol via Ethernet LAN	14.3 ms	37.4 ms
Vendor B GOOSE Protocol via Ethernet-to-WAN	18.3 ms	45.4 ms
Vendor A RSRP via Ethernet LAN	14.6 ms	42.1 ms
Vendor A RSRP via Ethernet-to-WAN	22.6 ms	50.1 ms
Vendor A RSRP via Serial LAN	5.2 ms	14.7 ms
Vendor A RSRP via Serial-to-WAN	9.2 ms	22.7 ms

Table 1: IED Timing Results for RAS System Protocol Tests Using the Three-IED RAS Scenario

4.4 System Reliability Analysis

Using fault tree analysis, SCE calculated the reliability of each system type to compare relative dependability and uptime. Table 2 lists the calculated expected downtime, which is a measure of unreliability due to unavailability of the RAS system. Each time a system becomes unavailable it also requires a substantial maintenance effort to return it to service.

Test Case	Availability	Predicted Average Annual Out-of-Service Minutes
Vendor A GOOSE Protocol via Ethernet LAN	99.982%	97
Vendor A GOOSE Protocol via Ethernet-to-WAN	99.962%	200
Vendor B GOOSE Protocol via Ethernet LAN	99.963%	192
Vendor B GOOSE Protocol via Ethernet-to-WAN	99.944%	295
Vendor A RSRP via Ethernet LAN	99.981%	100
Vendor A RSRP via Ethernet-to-WAN	99.961%	203
Vendor A RSRP via Serial LAN	100%	0
Vendor A RSRP via Serial-to-WAN	99.993%	37

Table 2: Reliability Analysis of Communications System Architectures via Fault Tree Analysis

The use of RAS communications realizes significant system benefits over traditional methods of using multiple copper terminations to measure field contact status, regardless of the protocol(s) or communications media. The reduced number of field terminations, associated wiring, labor, and maintenance due to the reuse of data detected by a single IED, digitally communicated to integrated IEDs and other data clients, led SCE to determine the following:

- The RSRP systems over serial and Ethernet interfaces both meet the acceptance criteria of the Ethernet RAS system.
- GOOSE protocol over Ethernet meets the acceptance criteria of the Ethernet RAS system.
- GOOSE protocol is available from multiple vendors; RSRP is available to all vendors for inclusion in their products.

5 REAL-TIME DIAGNOSTICS BECOME ESSENTIAL TO SUCCESS [4]

During testing, SCE noticed the inability to verify correct operation of the GOOSE messages on the Ethernet network unless the IEDs provided diagnostics. SCE found it essential that the IEDs provide such diagnostics to complement analysis available via network analyzers. Reference [4] illustrates diagnostics that provide necessary IED status and messaging status information directly from the in-service IED.

5.1.1 GOOSE Message Performance and Quality Monitoring

IEDs exchanging GOOSE messages automatically monitor the communications to determine message quality. Each device detects errors in received messages and failure to receive expected messages from other devices and performs remediation immediately. The errors codes indicating bad quality are summarized in Table 3. If the IED detects any of these to be true, it sets the message quality to failure.

Message Statistics	**Error Code**
Configuration revision mismatch between publisher and subscriber	CONF REV MISMA
Publisher indicates that it needs commissioning	NEED COMMISSIO
Publisher is in test center	TEST MODE
Received message is decoding and reveals error	MSG CORRUPTED
Message received out of sequence	OUT OF SEQUENC
Message time-to-live expired	TTL EXPIRED

Table 3: GOOSE Message Error Codes

5.1.2 Uniquely Identify Each Configuration Revision in the IED

IEC 61850 describes the substation configuration language (SCL) and configuration files, which configure devices for IEC 61850 communications. The preferred method is to load a configuration file, rather than individual settings, into the IED. Loading the file directly into the IED has several advantages over the legacy method of sending settings. A very important advantage is the ability to identify what communications behavior the IED is configured for by retrieving the file name and configuration revision directly from the IED while it is in service. Then it is possible to cross-reference the behavior of this IED and the behavior of other IEDs with the configuration files.

Further, by separating IEC 61850 configuration from other IED automation and protection settings via the SCL configuration file download, it is possible to be certain that no other settings were accidently modified or affected. This provides security by minimizing the impact to the system, minimizing the recommissioning after a change, and eliminating risk of unintentionally affecting the other processes within the system.

IEDs that support a GOOSE report provide real-time status of incoming and outgoing GOOSE messages and their configuration. Each report includes message configuration and performance information for each GOOSE message being published and for those to which the IED has subscribed.

Figure 1 illustrates a GOOSE report collected directly from an in-service IED named PAC_Master, which documents essential configuration parameters.

- GOOSE Transmit Status documents the configuration of the IED from which the report was retrieved.
  - The suffix _01 of the reference name confirms that the SCL file active in the IED is revision 01.
  - Multicast Address, Priority, VLAN, State Number, Sequence Number, Dataset Name, Time To Live, and Error Code are each displayed for each GOOSE message being published.
- GOOSE Receive Status documents the configuration of the IEDs and the associated GOOSE subscriptions configured to be received. Elements of the third subscription are highlighted to show configuration revision and error code.
  - The third subscribed GOOSE message is from an IED named PAC_SLAVE_B.
  - The suffix _01 of the reference name for PAC_SLAVE_B confirms that the SCL file active in the IED is revision 01.
  - Multicast Address, Priority, VLAN, State Number, Sequence Number, Dataset Name, Time To Live, and Error Code are each displayed for each GOOSE message being published.
  - In this case, the message is not being received and so the Time To Live has expired.

```
GOOSE Transmit Status

  Reference: PAC_MASTER_01CFG/LLN0$GO$Dset14_PAC_M_DO
  MultiCastAddr       Ptag:Vlan  StNum    SqNum    TTL   Code
--------------------------------------------------------------------------
  01-0C-CD-01-00-05    4:2      367      10298     1000
  Data Set: PAC_MASTER_01CFG/LLN0$Dset14_PAC_M_DO

GOOSE Receive Status

  Reference: PAC_SLAVE_A_01CFG/LLN0$GO$Dset14_PAC_A_DI
  MultiCastAddr       Ptag:Vlan  StNum    SqNum    TTL   Code
--------------------------------------------------------------------------
  01-0C-CD-01-00-01    4:2      60       18106     1198
  Data Set: PAC_SLAVE_A_01CFG /LLN0$DSet14_ PAC_A_DI

  Reference: PAC_SLAVE_A_01CFG/LLN0$GO$Dset15_PAC_A_AI
  MultiCastAddr       Ptag:Vlan  StNum    SqNum    TTL   Code
--------------------------------------------------------------------------
  01-0C-CD-01-00-02    4:2      73185    5         378
  Data Set: PAC_SLAVE_A_01CFG /LLN0$Dset15_ PAC_A_AI

  Reference: PAC_SLAVE_B_01CFG /LLN0$GO$Dset14_PAC_B_AI
  MultiCastAddr       Ptag:Vlan  StNum    SqNum    TTL   Code
--------------------------------------------------------------------------
  01-0C-CD-01-00-03    4:2      93732    6         0     TTL EXPIRED
  Data Set: PAC_SLAVE_B_01CFG /LLN0$Dset14_ PAC_B_AI
```

Figure 1: PAC_MASTER GOOSE Report Showing Transmit and Receive Configuration and Status

5.1.3 Calculate and Visualize GOOSE Message Reliability and Channel Availability

Once calculated and recorded as a timestamped SER, each GOOSE message quality status is used to calculate reliability and availability. Message quality indicates failure when a message is corrupted or not received within the Time To Live. The observation of failures indicates the reliability of individual GOOSE messages. If the message quality failure is intermittent, the duration of the failures is calculated as the difference between timestamps. The aggregate of failure duration over a given amount of time determines the channel availability. Figure 2 illustrates the use of the GOOSE quality status to alert users of a failed GOOSE subscription via the front-panel HMI to aid diagnostics and troubleshooting. In this case, a GOOSE with analog inputs (AI) from the IED labeled “C” has failed while the one labeled “B” is normal. It is also possible to use the status to trigger text messages and email messages to alert remote technicians.

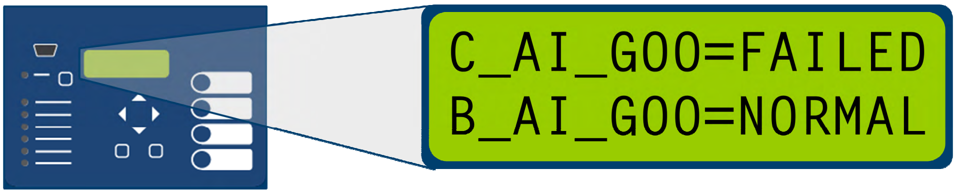

Figure 2: PAC HMI View of GOOSE Message Quality Display Point

6 IMPROVING THE STATE OF THE ART WITH SYNCHROPHASORS [5]

To date, synchronized phasor measurements have been used mainly for power system model validation, postevent analysis, real-time display, and other similar activities. However, synchrophasors have a greater potential than monitoring and visualization. Synchrophasors will increasingly contribute to the reliable and economical operation of power systems as real-time control and protection schemes become broadly used. Synchronous phasor measurements are now available in relays and meters; however, a practical means of processing the data in real time had been lacking.

Reference [5] describes the Synchrophasor Vector Processor (SVP) and several practical applications, including automated diagnostics, RAS, direct state measurement, and stability assessment. This real-time synchrophasor processor device further improves RAS and SPS systems by performing vector mathematics in real time.

6.1 The SVP

The purpose of the SVP is to collect synchronous phasor measurements (SPMs), collect logical inputs, perform vector and scalar calculations, make decisions, produce outputs, and report data. A simple task for an SVP might be collecting SPMs from two ends of a transmission line, comparing the voltage angles, and issuing a warning to an operator if a threshold has been exceeded. A more complicated example might be distributed SVPs performing localized substate measurement and forwarding results to a higher level to build the entire state vector in real time, without the nonlinear and time-consuming steps of state estimation.

6.2 Traditional RAS System Implementation

Figure 3 shows the timing diagram of a traditional digital communications RAS system. Included are the relay detection time and relay assertion output time. The system consists of approximately 73 individual pieces of equipment, including I/O modules and logic processors.

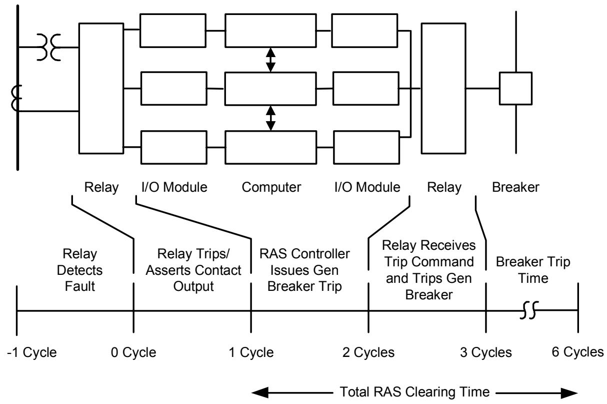

Figure 3: RAS Clearing Time Budget

6.3 SVP Implementation

For the SVP RAS implementation, the relays forward synchrophasor data, and the SVP determines if there is a loss of load, over-power, etc. The net result is that implementing an SVP solution and using high-speed communications tripping can save three quarters of a cycle.

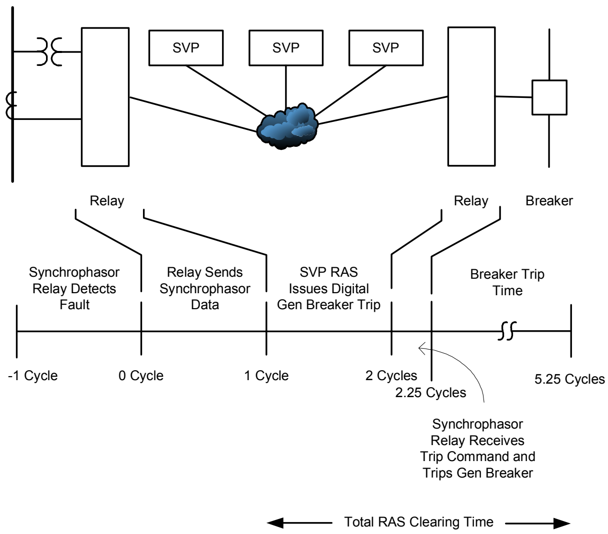

Figure 4: SVP RAS Clearing Time

7 CONCLUSIONS

1. Adding new generation to the transmission grid can impact the existing power system by potentially violating reliability criteria.

2. Impacts to existing power systems, typically caused by adding new generation to the established transmission grid, often include overloaded transmission lines, transformers, circuit breakers, and other system components that may cause violations of accepted reliability criteria. RAS schemes are designed to rapidly acquire power system measurements and manage generation and load to prevent violations and provide stability.
3. The use of digital communications for RAS data acquisition and control realizes significant system benefits over traditional methods of using multiple copper terminations to measure field contact status, regardless of the protocol(s) or communications media. The number of field terminations, associated wiring, labor, and maintenance is reduced due to the reuse of data communicated digitally.
4. IEC 61850-3 Section 4 summarizes design practices and reliability measures useful to maximize system reliability and availability.
5. GOOSE reports provide quick troubleshooting diagnostics by documenting configuration and status of incoming and outgoing GOOSE messages.
6. Now that SPMs are broadly available from protective relays and meters, it is time to put them to work to improve our power systems. The SVP makes real-time applications practical.
7. Direct state measurement is now practical because of the widespread availability of SPMs. The SVP plays a role in direct state measurement and can actually reduce the amount of information communicated to the master station.

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9 BIOGRAPHY

David J. Dolezilek is the technology director of Schweitzer Engineering Laboratories, Inc. He is an electrical engineer, BSEE Montana State University, with experience in electric power protection, integration, automation, communications, control, SCADA and EMS. He has authored numerous technical papers and continues to research innovative technology affecting our industry. Dolezilek is a patented inventor and participates in numerous working groups and technical committees. He is a member of the IEEE, the IEEE Reliability Society, CIGRE working groups, and two International Electrotechnical Commission (IEC) Technical Committees tasked with global standardization and security of communications networks and systems in substations.

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