Comparison of Analogue Measurements Between Merging Units and Conventional Acquisition Systems

C. A. Dutra*, I. H. Cruz*, T. A. Franzen*, R. R. Matos*, F. C. Neves*, L. B. Oliveira*, G. Krefta†

**Reason Tecnologia S.A., Brazil, carlos.dutra@reason.com.br, †COPEL, Brazil*

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Abstract

This paper presents the recent progress in use the sampled measured values (SV) as described in IEC 61850-9-2 and IEC 61869. This protocol is used to replace the copper cabling for digital communication network in bringing the current and voltage measurement for protection and control substation systems. The technology is implemented through an equipment called merging unit, which digitizes the analogue measurements and encapsulate the information in proper network packets. The progress in the implementation of IEC 61850 SV is corroborated by the excellent results when comparing analogue measurements between merging units and conventional acquisition systems, as presented in this work. In chapter 2, tests are carried out by comparing the standard and SV approach using a DFR. Chapter 3 and 4 include a protection relay in the tests to compare protection actuation using the two systems. Finally, chapter 5 presents results of a field application of merging units in real power system substation. In conclusion, the results and sources of error are analyzed and validated.

1 Introduction

In conventional substations, every device in the relay room, such as protective relays and digital fault recorders have their own acquisition systems. All cables from the switchyard (including those from instrument transformers), are directly connected to the analogue inputs of these devices. IEC 61850 process bus changed this reality. The standard's approach is to consider the Ethernet network as the means of data transportation from the switchyard to the relay room. [1,3]

In this configuration, a special device called merging unit performs the data acquisition system. The current and the voltage analogue measurements are sampled and converted to digital values, which are then transmitted through the network in standardized messages known as Sampled Measurement Values (SV), as described in IEC 61850-9-2 and IEC 61869. [2]

Merging units must provide SV packets with the magnitude and phase accuracy similar to that provided by the conventional acquisition system in order to keep the requirements of the system. Furthermore, as the samples created by merging units are not time-stamped but rather incremental counts, the sampling and transmission of the packets has to be very stable with respect to time. It means that, for example, in the case of a nominal frequency of 60 Hz and a sample rate of 80 frames/cycle (protection profile), every sample must be sent to the network spaced in 208 microseconds. The sample sequence number is stored on a predefined field in the sampled measured value packet. Additionally, it is imperative that the first sample of the second be as close as possible to the PPS (Pulse per Second) turnover. Good stability of the Merging unit is bound to these characteristics and they are strongly dependent on the performance of the internal algorithms to process the data and keep the time synchronization of the acquisition system.

In their turn, digital fault recorders provide COMTRADE records in order to analyze the disturbances in the power line. Their acquisition systems usually have good frequency response and good accuracy in magnitude and phase to provide reliable information to the analyst in order to check the behavior of the protection system during an event.

In order to compare the behavior of conventional acquisition systems and the Merging unit sampled values, practical tests regarding the performance of these systems were performed. By using a device able to read sampled values and conventional measurements, such as a digital fault recorder, a protection relay and a test-set, COMTRADE files were created and their the performance analyzed.

Similar analysis are being performed in a Process Bus pilot installation at a 230 kV substation, to compare a complete conventional system (PT/CT with copper cables plus relay) and a process bus architecture (PT/CT, merging unit plus network data infrastructure and relay).

2 Tests with a digital fault recorder (DFR)

To perform this test, analogue current and voltage signals were generated with levels compatible with the secondary of the instrument transformers. The signals were then injected to the device under test (DUT), the merging unit (MU) and also to the digital fault recorder (DFR). Finally, the sampled measured values generated by the DUT were read by the DFR and compared to the straight through analogue connection.

As a requisite for the operation of the system, both the DRF and MU are synchronized in time using a GPS grandmaster precision clock equipment. Additionally an Ethernet switch suitable for IEC 61850 applications was used for the equipment interconnection of the equipment. The overall view of the system is shown in

Figure 1.

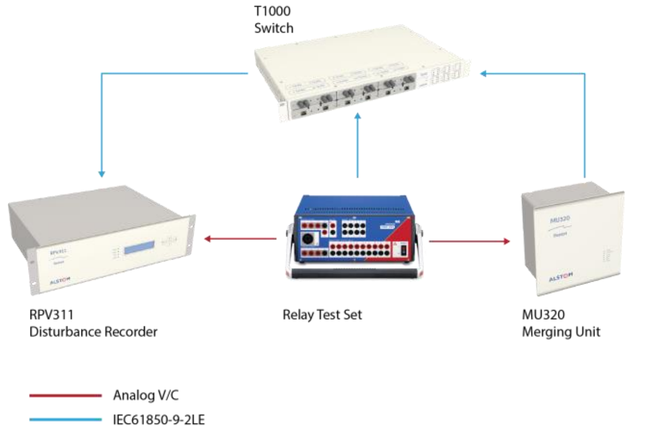

Figure 1: MU and DRF tests block diagram

The DFR was configured to monitor two circuits, one for the conventional circuit and the other for the sampled values readings. In Figure 2 the online monitoring tool of the DFR is presented, showing the two measurements and phasors side-by-side. The nominal values for verification were the following: 66.4 V; 5 A; 60 Hz. Tables 1-4 ahead show the result of data valuation and their respective errors.

Voltage phasor module [V]	*MU*	*Conventional*	*Error (%)*
Phase A	66,37	66,40	0,05%
Phase B	66,43	66,38	0,08%
Phase C	66,38	66,41	0,05%

Table 1 - Voltage amplitude valuation

Voltage phasor angle [º]	*MU*	*Conventional*	*Error (%)*
Phase A	-90,00	-90,00	0,00
Phase B	149,98	150,00	0,02
Phase C	29,99	29,99	0,00

Table 2 - Voltage phase valuation

Current phasor module [A]	*MU*	*Conventional*	*Error (%)*
Phase A	5,00	5,00	0,00%
Phase B	5,00	5,00	0,00%
Phase C	5,00	5,00	0,00%

Table 3 - Current amplitude valuation

Current phasor angle [º]	*MU*	*Conventional*	*Error (%)*
Phase A	-89,81	-90,02	0,21
Phase B	150,13	149,98	0,15
Phase C	30,10	29,96	0,14

Table 4 - Current phase valuation

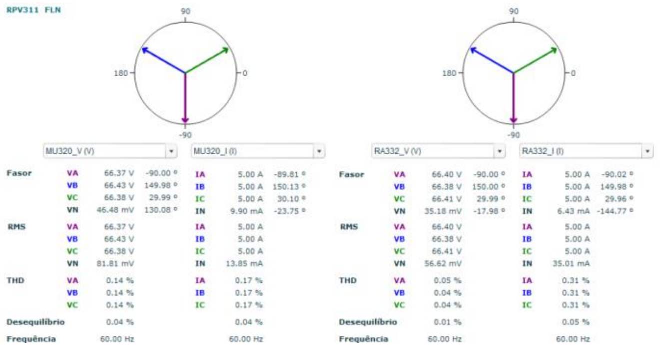

Figure 2: Phasor online valuation

With the same test scheme, transitory signals were also injected and analyzed. In the first case, the voltage from phase A was altered to zero (Figure 3) and in the second case, the phase B voltage was matched to phase A voltage. For the current circuits, an instantaneous overcurrent was generated as shown in Figure 5.

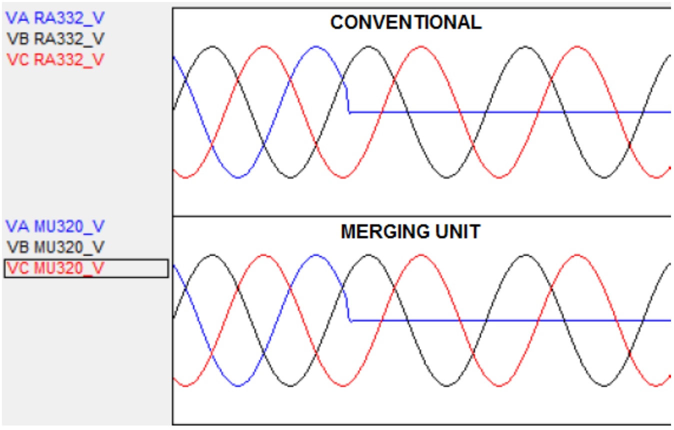

Figure 3: Transitory valuation (Va = 0)

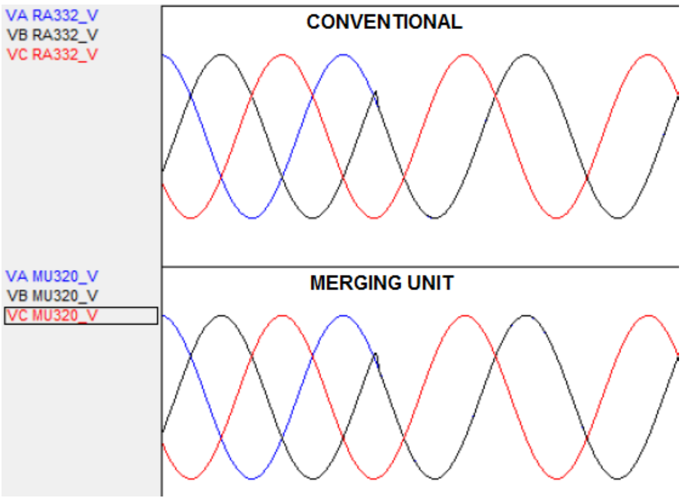

Figure 4: Transitory valuation (Va = Vb)

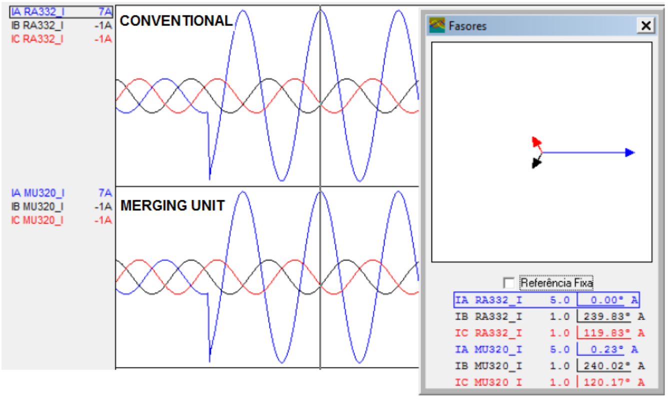

Figure 5: Transitory valuation (overcurrent Ia)

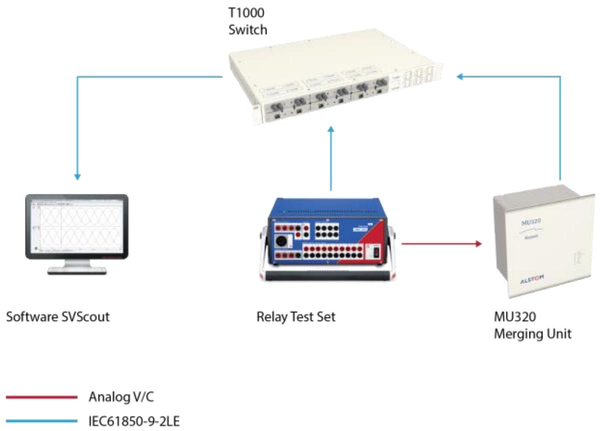

Figure 6: MU and relay test set tests block diagram

In all cases, the responses observed by the conventional system DFR acquisition and through the merging unit had negligible differences.

3 Testing IEC 61850 MU with test sets

In the last, few decades a test bench philosophy for protection equipment has been adopted which is the use of test sets to apply known and controlled voltage and currents signals to the units under test and verify the correct reading and behavior. When using IEC 61850 this philosophy is maintained, although the tools might be appreciably different.

For this application, a relay test set CMC353 (Omicron) was used to generate the current and voltage signals. This test set can generate current and voltage signals in the conventional analogue way but also with sampled values. This allows the comparison of a logically created stream of sampled values, the ones generated by the relay test set, to the stream resulting of the merging unit processing. The scheme for the test is shown in Figure 6.

In order to verify linearity, the three voltages and currents signals were generated in a variety of amplitudes. The charts in Figure 7 and Figure 8 show the results of phase A voltage and phase B current along with a perfect 45 degrees line. In the overlap, it is observed that the linearity of the signals are perfect, both current and voltage.

On the voltage signal was verified a maximum error of 0.08%. For current, an error of 3.06% was verified in the 100 mA d.c. measure. This error is a known limitation of the capacity of the analogue to digital conversion and derives from the requirement imposed on the devices of measuring up to 20 times their nominal current input. This leads to either a low resolution or expensive conditioning and conversion systems. Disregarding the measurement of 100 mA, the maximum error found in the current measurements was 0.11%. Along with the voltage results, the conclusion is that the equipment is suitable for power systems protection and measuring applications.

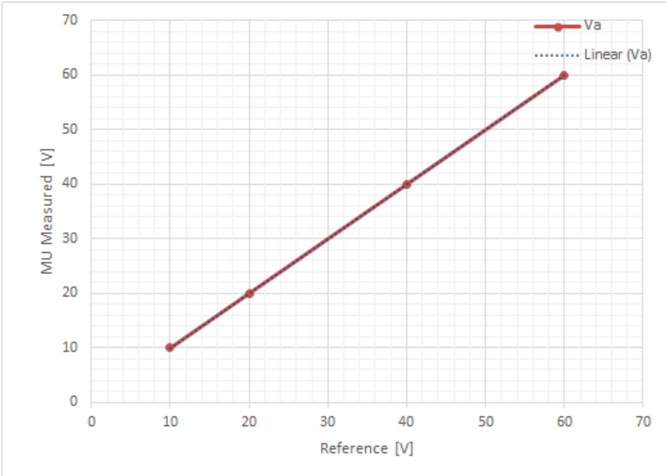

Figure 7: Voltage range valuation (scales in V)

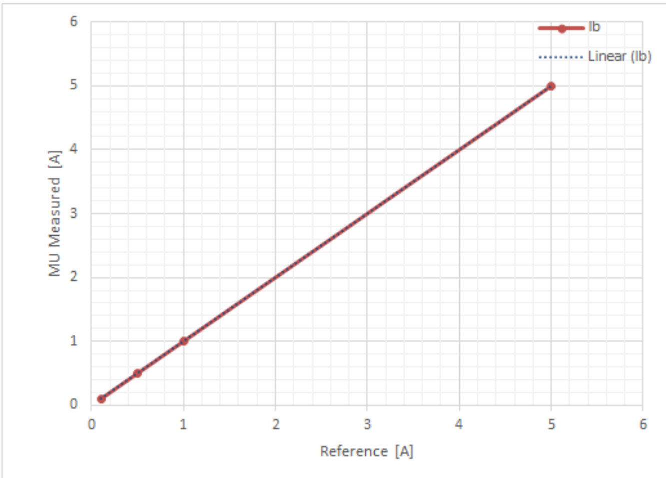

Figure 8: Current range valuation (scales in A)

4 Harmonic verifications

A potential problem to protection systems is the presence of harmonic distortion during pre-fault and fault periods. In this condition is relevant that the signal measure can be read by the IED and appropriately treated by itself, individually for each protection function.

For this purpose the MU must read and transmit to each IED a faithful reproduction of voltages and currents. To prove this, a test scenario was carried out with analogue current and voltage signals generated with levels compatible with the secondary of the instrument transformers and a known percentage of harmonic distortion. The test was performed throughout the frequency range by inserting individual harmonic distortion to each odd component separately.

The sampled values generated by the MU were captured by the DFR and analyzed in the Analise COMTRADE viewer software. These tests were carried up to 15^{th} component (900 Hz component @ 60 Hz system) because this is an excellent range of conventional protection relay and because this is the limit of the voltage/current generator system. The results are shown in the table ahead.

Harmonic	Frequency (Hz)	Magnitude Ref.	Voltage HD measur.	Current HD measur.	Voltage error	Current error
3	180	10%	10,00%	10,10%	0,00%	0,10%
5	300	10%	10,00%	9,98%	0,00%	0,02%
7	420	10%	9,98%	9,97%	0,02%	0,03%
9	540	10%	9,95%	10,01%	0,05%	0,01%
11	660	10%	9,92%	10,01%	0,08%	0,01%
13	780	10%	9,84%	10,02%	0,16%	0,02%
15	900	10%	9,74%	9,94%	0,26%	0,06%

Table 5 – Harmonic distortion tests

To find out the intrinsic error of the IED–which is present in any analog/digital systems–a measurement was carried with no harmonic distortion in voltage and current. The next table shows these errors.

Harmonic Component	Frequency (Hz)	Magnitude Ref.	Voltage HD measur.	Current HD measur.
3	180	0%	0,01%	0,12%
5	300	0%	0,01%	0,07%
7	420	0%	0,01%	0,05%
9	540	0%	0,04%	0,06%
11	660	0%	0,05%	0,05%
13	780	0%	0,01%	0,02%
15	900	0%	0,02%	0,02%

Table 6 – Intrinsic errors

Thus, considering the intrinsic errors and analyzing the measured values errors, the system (MU + process bus + DFR) has a perfect reproduction with same response that is expected in a conventional protection equipment (with straight-through connection).

4 Protection tests

The procedure to test a digital protection relay, that allows the direct measuring of current and voltage and also the reading of the same signals via sampled values obtained from a merging unit, can be complex, create unwanted errors and be

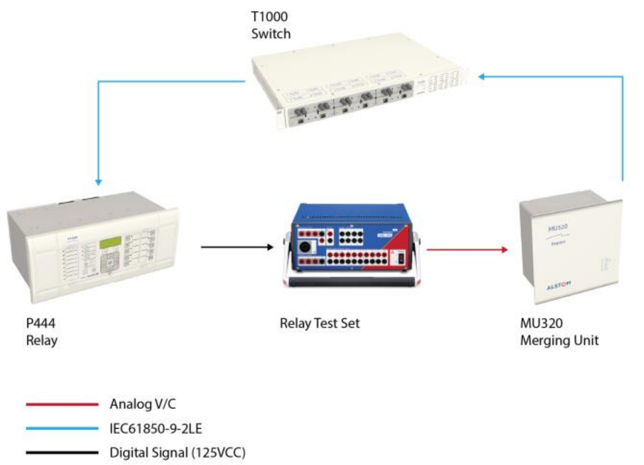

Figure 9: Protection test block diagram

of difficult measuring. This is mainly due to the sampled values technology being somewhat recent and not very familiar to many engineers.

As such, the main purpose and focus of the test herein presented is to reproduce the fundamental principle of validation of the protection function, which is to use relay test sets to create faults and then measure the time taken for the protection function to initiate.

This kind of test is exceptionally important as it directly returns what we are usually interested in a protective system, the time that taken by the system to operate (creating a trip output) after the occurence of a real fault.

In this test, the overcurrent function was configured with an Alstom P444 relay operating with the voltages and currents coming from the merging unit model Reason MU320. The test set used for generating the voltage and current signals was the model Omicron CMC353.In order to verify the reaction time of the P444, the conventional trip signal from the relay by contact (hardwire) was monitored using the CMC353. This setup is shown in Figure 9.

Ten different kinds of overcurrent were created operating in the 60 Hz frequency, with pre-fault current equal to zero. The trip times are shown in Table 7.

The average operating time was about 18 ms, considered adequate for current pre-fault zero condition. Also observed is the repeatability of the results, with a standard deviation of only 0.26 ms.

Cases with pre-fault current of five amps were also tested with trip time occurring at around 10 ms. It is noted that several test cases were not performed, since the focus was the acquisition of the signals using a merging unit. Other tests could bring discrepancies on the trip time because of the protection relay performance, and their result would be no different even with the direct acquisition of voltage and current signals.

Case	*Time (ms)*
1	17,70
2	17,90
3	18,30
4	17,80
5	18,30
6	18,20
7	17,80
8	18,20
9	18,40
10	17,80
Mean	**18,04 (σ ±0.26)**

Table 7 – Protection trip times

5 Field tests in a substation

Field analyses are being performed in a Process Bus pilot installation at Uberaba Substation, a 230 kV substation owned by COPEL, one of the largest transmission companies in Southern Brazil. The process bus architecture was designed and installed in parallel with the line protection system already in service in a 47.4 miles line. This substation was chosen because historically it has a higher probability of events and many incidents of protection triggering and line openings. This makes it possible to evaluate the sampled values performance in comparison with the conventional system using real disturbance data.

A merging unit was installed in the substation switchyard in order to receive the voltage and current signals from the respective instrumentation transformers. This merging unit was connected, via fiber optic cables, to the network infrastructure in the relay room. Figure 10 shows the merging unit installed in the switchyard of the substation. As it is clears on the picture, the merging unit is installed in an appropriate panel where test switches were accommodated and the CT and VT cables connected.

The sampled values generated by the merging unit are used by a protection relay, with the same philosophy and adjustments of the existing relay. Additionally, a digital fault recorder is connected to the process bus reading the same sampled values and monitoring the performance of the (simulated) blockade. For proper order, all devices are synchronized by a GPS-based clock. The block diagram in Figure 11 shows this application.

All the equipment was commissioned in March 7, 2014. At this stage, it is possible to do a steady-state evaluation. This is carried out with the cross-trigger function of the two DFR equipment, i.e., a manual trigger in on the process bus DFR causes a trigger on the conventional DFR in the same network. A set of records were made in order to compare the measured currents. The deviation between currents phasors are shown in the following tables.

Figure 10: Field installation of MU320 panel at COPEL's Uberaba substation.

	1		**2**		**3**	
Current phase A	**Module (A)**	**Phase (º)**	**Module (A)**	**Phase (º)**	**Module (A)**	**Phase (º)**
Conventional DFR	63.9	311.45	63.8	311.37	63.9	311.57
Process bus DFR	64.1	311.08	64.1	311.05	64.0	311.06
Deviation	0.3%	0.37	0.5%	0.32	0.2%	0.51

Table 8 – Phase A current deviation

	1		**2**		**3**	
Current phase B	**Module (A)**	**Phase (º)**	**Module (A)**	**Phase (º)**	**Module (A)**	**Phase (º)**
Conventional DFR	61.8	310.66	62.1	310.66	61.9	310.67
Process bus DFR	62.2	310.58	62.5	310.65	62.4	310.70
Deviation	0.6%	0.08	0.6%	0.01	0.8%	0.03

Table 9 – Phase B current deviation

	1		**2**		**3**	
Current phase C	Module (A)	**Phase (º)**	**Module (A)**	**Phase (º)**	**Module (A)**	**Phase (º)**
Conventional DFR	59.3	310.65	59.6	310.78	59.4	310.63
Process bus DFR	59.3	310.33	59.1	310.41	59.1	310.31
Deviation	0.0%	0.32	0.8%	0.37	0.5%	0.32

Table 10 – Phase C current deviation

For the currents modules is possible to observe a mean error of 0.5% and for the phase of 0.26º. Considering all the errors as time synchronization, analog to digital conversion, among others, these are good results.

This analysis was made with 60 A of primary current and the CT has 1200 / 5 relation. Therefore, this measure uses only 0.25% of DFR scale range. Reminding that protection system must be able to operate in this condition (low current) than it is an excellent indication of the MU performance.

An overview of waveform in this condition is shown in figure 12.

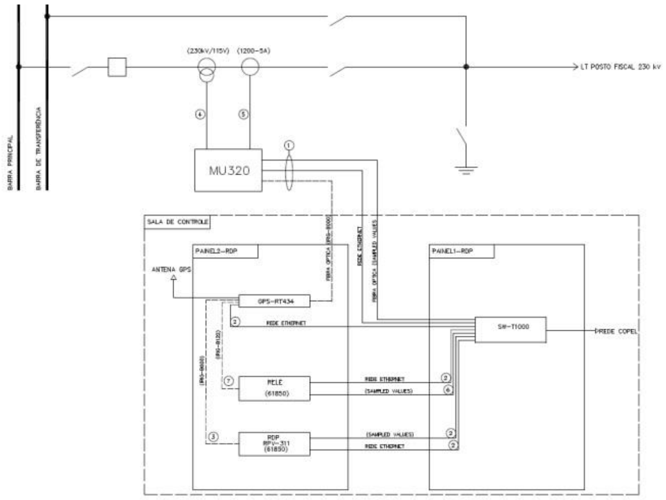

Figure 11: Field test block diagram

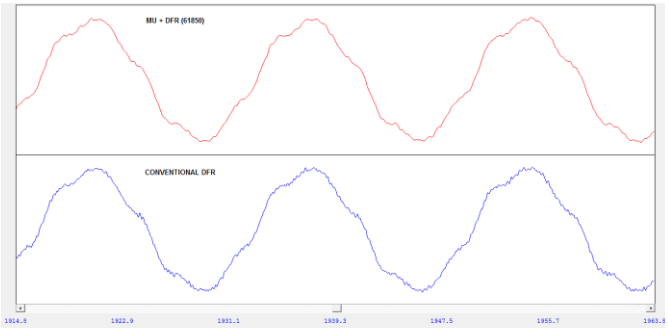

Figure 12 – Currents phases A comparison

Conventional (wired) DFR uses a 15.36 kHz sample hate (256 s/c: measurements purpose) and the process bus DFR uses a 4.8 kHz sample rate (80 s/c: protection purpose). In this case is possible to observe a small noise in a conventional DFR because it has a better discretization.

In the same way as for currents the deviations were calculated for voltages. The deviation between voltages phasors are shown in the next tables.

	1		2		3	
Voltage phase A	**Module (kV)**	**Phase (º)**	**Module (kV)**	**Phase (º)**	**Module (kV)**	**Phase (º)**
Conventional DFR	136.1	311.44	136.1	311.46	136.1	311.44
Process bus DFR	136.3	311.13	136.3	311.14	136.3	311.12
Deviation	0.1%	0.31	0.1%	0.32	0.1%	0.32

Table 11 – Phase A voltage deviation

	1		2		3	
Voltage phase B	**Module (kV)**	**Phase (º)**	**Module (kV)**	**Phase (º)**	**Module (kV)**	**Phase (º)**
Conventional DFR	137.3	49.18	137.3	49.17	137.3	49.18
Process bus DFR	136.2	49.47	136.2	49.46	136.2	49.48
Deviation	0.8%	0.29	0.8%	0.29	0.8%	0.30

Table 12 – Phase B voltage deviation

	1		2		3	
Voltage phase C	**Module (kV)**	**Phase (º)**	**Module (kV)**	**Phase (º)**	**Module (kV)**	**Phase (º)**
Conventional DFR	136.4	311.45	136.4	311.46	136.4	311.44
Process bus DFR	137.4	311.15	137.4	311.16	137.4	311.14
Deviation	0.7%	0.30	0.7%	0.30	0.7%	0.30

Table 13 – Phase C voltage deviation

Errors of the same order of magnitude were observed for those exposed to currents. They are 0.6% for modules and 0.3º for phases. Similar evaluations were conducted with others currents levels in steady state condition, with the same response.

The equipment will continue in operation in order to obtain records to compare the process bus application with a conventional under real fault conditions.

6 Conclusion

The deviations found are well within the acceptable levels for two distinct signal acquisition systems. Such deviations occur due to differences in the electronic chain of analogue/digital conversion, i.e. would occur in the comparison between two conventional digital devices. Thus, the performance expected for the merging unit, when compared to a conventional protection system is adequate for the same types of applications.

That means the functionality of protection and measuring using a merging unit is guaranteed. Additionally, recent development work has indicated a strong possibility of reduction in operating times for protection, returning to sub-cycle triggers.

Therefore it is possible to benefit from the reduced cabling costs, flexibility in design and implementation of protection schemes with the guarantee of proper operation. In addition, there is also the added benefit of ensuring the correct measurement is being received, due to self-monitoring and attesting receipt of the data communication network.

Furthermore, it has been shown that devices and systems for protection testing are already able to perform validation tests using IEDs with full 61850 compatibility. Field installation of such IEDs to actual operating condition is an important step towards implementing a fully digital substation with all its intrinsic benefits. This first step has been accomplished in this work and the continuous monitoring of such installation will bring insight and familiarity to the utility crew personnel on this new operation paradigm.

Although a comparative analysis of the performance with a conventional system in the field could not been completed at this time, this was not considered an impediment to the findings presented here, since the protection test systems in use enable efficient validation. Anyway, additional laboratory tests continue to be conducted taking into account other operating conditions, such as different types of faults (two-phase, three-phase, with or without ground fault) and currents and voltages with harmonic distortion.

Although not directly addressed in these tests, the question of communication network performance is a crucial factor, which should not be overlooked when similar assessments are carried out in the design of a protection system. The topology of the network devices (switches, routers) and their connection to the IEDs, as well as the correct configuration of network parameters are primary conditions to ensure that the merging units exhibit the expected performance.

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