# The Return of the Dedicated DFR

## How IEC 61850 Process bus simplifies DFR installation

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## 1. Summary

The advantages of a dedicated, standalone DFR are well known: natively synchronized fault records, large record storage capabilities, high sampling rates, numerous types of triggers, and large numbers of analog and digital recording channels. The main disadvantage to the dedicated DFR is cost: a dedicated DFR must be directly wired to every current, voltage, and status point, resulting in an installed project cost easily 10 times the material cost of the DFR itself. For this reason, electric utilities have been moving away from dedicated, standalone DFRs. Microprocessor-based protective relays and phasor measurements units are already being installed for core system operations. The recording capabilities of microprocessor-based protective relays, and the ability of phasor measurement units and phasor data concentrators to provide disturbance recording data, make relays and PMUs adequate as a complete fault recording system.

However, IEC 61850 process bus makes dedicated DFRs affordable again, by eliminating all field wiring necessary for installing a DFR. Merging units, installed for protection purposes, can also provide sampled value measurements to a DFR. DFRs can acquire digital status points through GOOSE messages from merging units and protective relays. In short, the installation cost of a DFR that supports process bus is simply that of device configuration. The only field wiring necessary is power, case grounding, and a network connection to the process bus network.

A well-designed DFR installation will work in wholly process bus applications, as well as mixed process bus / conventional applications, presenting expected cost savings of both architectures. In addition, related capabilities, such as travelling fault location might be integrated in the same device.

## 2. Introduction

The term "DFR" or a "transient fault recorder" is a word that is substitution for an application requirement: the desire to make specific types of time coordinated nonoperational data available to understand how power system equipment responds to specific conditions. This nonoperational data includes fault recording or oscillography, capturing the behavior of the power system current and voltage waveforms at a high resolution. Sequence of events recording, that documents the operation of power system equipment. And disturbance recording, that shows the general behavior of the power system during all conditions.

This nonoperational data can be used to:

- Understand and document how secondary equipment and primary equipment respond to abnormal events such as short circuits
- Document, verify, and analyze the performance of primary equipment to enable better maintenance practices

- Verify power system models and short circuit calculations
- Identify power quality disturbances and provide for event analysis
- Detect incipient failure of primary equipment such as bushings and instrument transformers
- Understand wide-area power system disturbances, including power system oscillations
- Provide data for power system planning models

Transient recorders were created to specifically to provide this data when no device existed that could do this. As a result, the tendency is to conflate the application with the device: a DFR is needed to provide the recording data, when the discussion should be around the best method to capture the required nonoperational data.

## 2.1. General DFR application requirements

In many regions or countries, regulatory requirements define the most basic transient recording requirements. In North America, NERC PRC-002-2 Disturbance Monitoring and Reporting Requirements[1] define these minimal requirements. PRC-002 defines the data to be captured for post-fault event analysis, specifically fault recording data, sequence of events recording data, and dynamic disturbance recording data. These requirements include minimum sampling rates, general triggering conditions, and record retention policies. These are minimal requirements related to documenting the performance of the bulk electric system. Other data may be required to meet specific analysis needs.

It is important that all data captured for an event, even if captured across multiple devices, are time coordinated. This allows the practical analysis of event data, across all impacted substations and equipment. For convenience, it is desirable to produce a coherent record, where all data is combined into one time coordinated record or file.

When talking about recording, it is common to describe each input source as a channel. Channels can be analog changes, that record current and voltage waveforms, with one channel per phase. Channels can also be digital channels, or contact inputs that record the status of primary equipment, signaling equipment, protective relays, and other power system equipment.

### 2.1.1. Types of recording

Fault recording is also known as oscillography: the capture of actual power system current and voltage waveforms. PRC-002-2 requires a minimum sampling rate of 16 samples per cycle. Other regional coordinating councils may require a higher sampling rate. The typical sampling rate for recording is 64 samples per cycle or higher.

Fault recording data from different devices must be captured in a format that makes coordination, combination, and coherence between these records easy to achieve. The IEEE COMTRADE[2] format is the industry standard defining requirements specifically, and the goal should be that all recording equipment either natively captures data as COMTRADE files, or supports easy conversion to COMTRADE files.

Sequence of events records (or SER in PRC-002) should capture the change of state, with a timestamp, for every digital channel recorded. This allows the recording to show the interaction for the operation of secondary equipment, such as protective relays and protective relay communicatioins, and primary equipment such as the opening and closing of circuit breakers. As with fault recording, a requirement is  to compare sequence of events records from different devices for the same event. The ideal format going forward is the one described by the IEEE COMFEDE standard. [3]

Disturbance data required by PRC-002 is phasor data for analog values. These values are typically captured a low rate of one phasor per cycle or slower. Traditionally, this data has been simply RMS data for currents and voltages. Going forward, this data is more likely to be synchrophasor data: explicitly system-wide time coordination phasor data, as described in the C37.118.1 standard for synchrophasor standard. [4]

An obvious conclusion to draw from this discussion is that standards, to define the commonality, interoperability, and usability of data, are becoming more important of the acquisition and use of nonoperational data.

### 2.1.2. Triggers

It is necessary to trigger the capture of full recording data on abnormal power system conditions, and the operation of specific types of secondary and primary equipment. This requires recording on the change of state of analog measurements, on the change of state of primary equipment status, and on the reception of other signals or alarms. Triggers are set individually for each analog and digital channel. Typical triggers for analog measurements involve current above a specific threshold, voltage below a specific threshold, and system frequency outside of specific. Digital channel triggers include such events as the operation of protective relays, initiate signals for protection system communications, and the opening and closing of primary equipment such as circuit breakers.

It is generally desirable to trigger on the raw power system conditions, as well as on faults declared by protective relays. One goal of data analysis is to verity the operation (or nonoperation) of protective relay elements, so these elements should not be the sole source of recording triggers.

### 2.1.3. Data storage and retention

Records need to be of adequate length to show high resolution power system response during fault events and abnormal conditions. These records need to show from the actual Inception of the fault to the point the fault was successfully cleared by primary and secondary equipment. Fault records must therefore include both pre - and post -fault data. A minimum record length of 5 to 10 cycles of pre-fault data, 10-15 cycles of fault event data, and 5-10 cycles of post-fault data.

PRC-002 defines general requirements for record length, and local (to the substation) and remote record retention periods. In general, it is required to store recordings locally for a minimum of one month.

Disturbance recording data should be captured in records, and should be continuously recorded. The minimum requirement is to store 2 weeks of continuously recorded disturbance data locally in the substation.

#### 2.1.4. Other requirements

There are other general requirements for recording. These include the number and type of channels to record, and the number of devices required to record. 64 analog channels and 128 digital channels is normally adequate for a typical transmission substations. There is no need to duplicate recording of each channel.

It is also desirable to trigger on and record other types of data. These can include calculated analog channels, such as power and energy. Beyond these, it is useful to record analog data used by protective relay elements, such as differential and restraint currents and apparent impedance.

## 3. Review of DFR Installations

DFRs and transient recording describe a set of application requirements. Specific devices have been designed, or adapted, to meet these requirements. The use of these devices leads to several general architectures to accomplish recording.

### 3.1. Centralized DFR

The first DFRs or transient recorders were centralized devices, and many modern DFRs are still centralized devices. All data is analog data, directly wired between the primary and secondary equipment sources of the data, and the DFR itself. Every recording channel therefore requires a pair of copper wires, connected from the primary equipment. These wires to collect raw data are installed in parallel to, or as an extension of, wiring already installed for protection and control systems, metering, and other similar types. A pair of wires is therefore required for every input channel to the DFR.

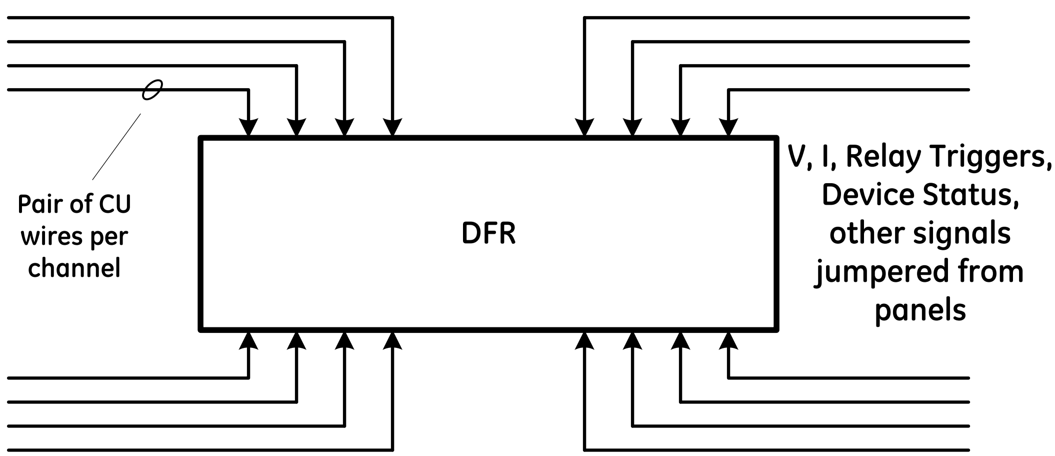


Figure 1: Centralized DFR

A centralized DFR captures recordings based on triggers asserted on changes of state of the input channels. These can be triggers on analog measurements, such as overcurrent conditions, or the assertion or deassertion of a binary input channel, such as a protective relaying trip indication. The general goal is to have the trigger be independent of the performance of other secondary equipment, such as protective relay element operation.

One key benefit of a centralized DFR is that records capture all channels simultaneously, in a common format, with a common sampling rate. Therefore a coherent record is achieved: all data are natively coordinated to each other, and records are captured with a record-based time stamp.

The biggest concern of a centralized DFR is the cost of installation. Every input channel involves a pair of copper wires. A typical 36 analog channel, 64 digital channel DFR requires 200 copper wires, and a minimum of 400 wiring terminations, installed between the DFR, relay panels, and primary equipment. The total project cost of installing a DFR can easily be 10 times the material cost of the DFR itself. Also, the DFR becomes a separate device that must be configured and maintained.

## 3.2. Distributed DAUs

One industry solution to address the installation costs of a DFR is the use of data acquisition units (DAUs). Instead of wiring every analog signal directly to the DFR, a DAU is installed closer to the source of the signals, and sends data back to the main DFR through some form of communications. The intent is for the DAU to be dumb, distributed I/O for the DFR system.

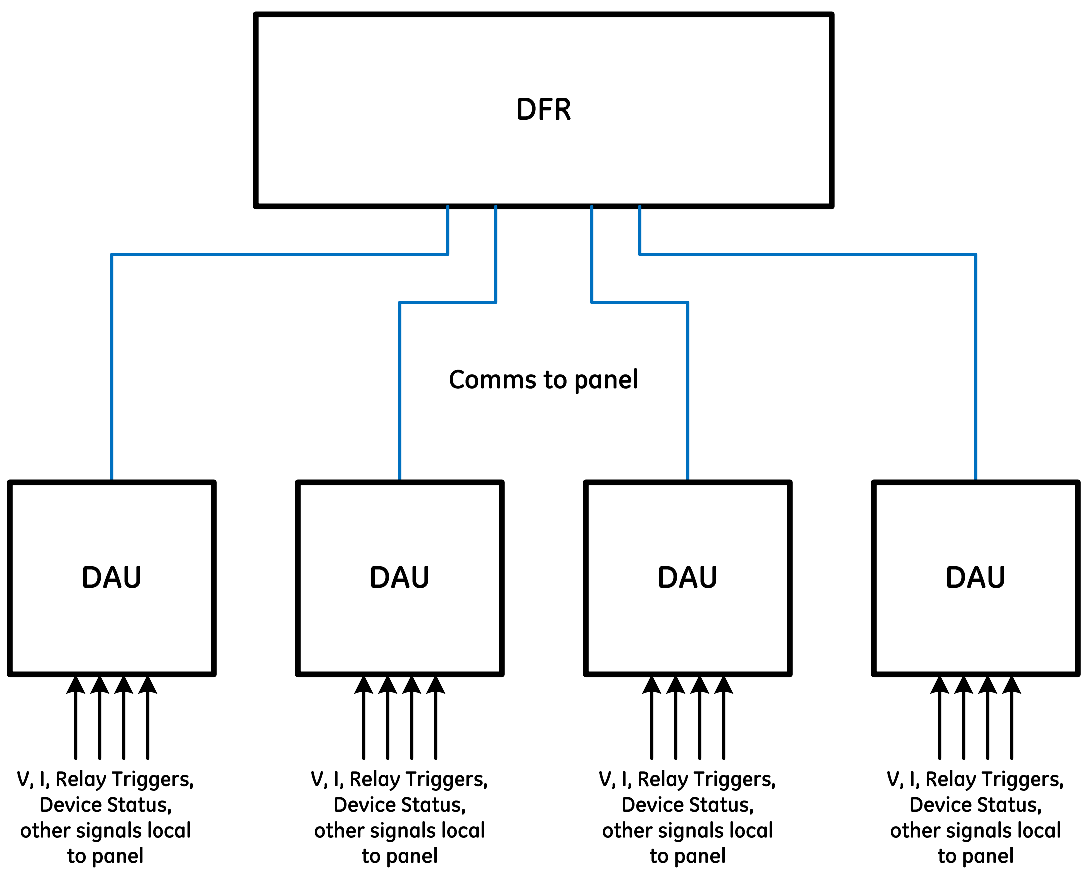


Figure 2: Distributed DAUs

DAUs may be installed anywhere, but are most typically installed in protective relay panels, because most signals are already wired to these relays panels. The communications between the DAUs and the DFR may take any form: analog signals, serial communications, or digital communications. The communications method and protocol is normally proprietary to the equipment vendor, with DAUs and the DFR acting as a closed system.

The actual DFR is still a centralized DFR unit. The main unit is responsible for all data processing, calculations, triggering, and storage. The DAUs are data acquisition only. Therefore, the distributed DAU model maintains all the advantages of a centralized DFR in regards to triggering. data capture, simultaneous recording, and the like. All record storage takes place in the DFR unit.

The advantage of using DAUs is in installation cost. Though every channel requires a pair of copper wires to the DAU, these wires will be local to the DAU. DAUs may be installed when relay panels are built, transferring the main work of wiring to panel builders. The only on-site wiring and commissioning required is connecting the DAUs to the main DFR unit.

The downside is that there is still a significant installation cost to the DFR, as the DAUs still must be wired in parallel to other secondary devices. The communications method is typically proprietary, limiting flexibility. And the DFR and DAUs are devices that must be installed and maintained.

## 3.3. Distributed DFRs

Another industry solution to the challenge of installation costs is the concept of a distributed DFR. This extends the concept of the DAU, to turn the DAU into an individual DFR, with a DFR installed in every relay panel. A DFR data concentrator is then used to collect and synchronize the records from individual DFRs, and for bulk record storage. This concept, at heart, is intelligent DAUs.

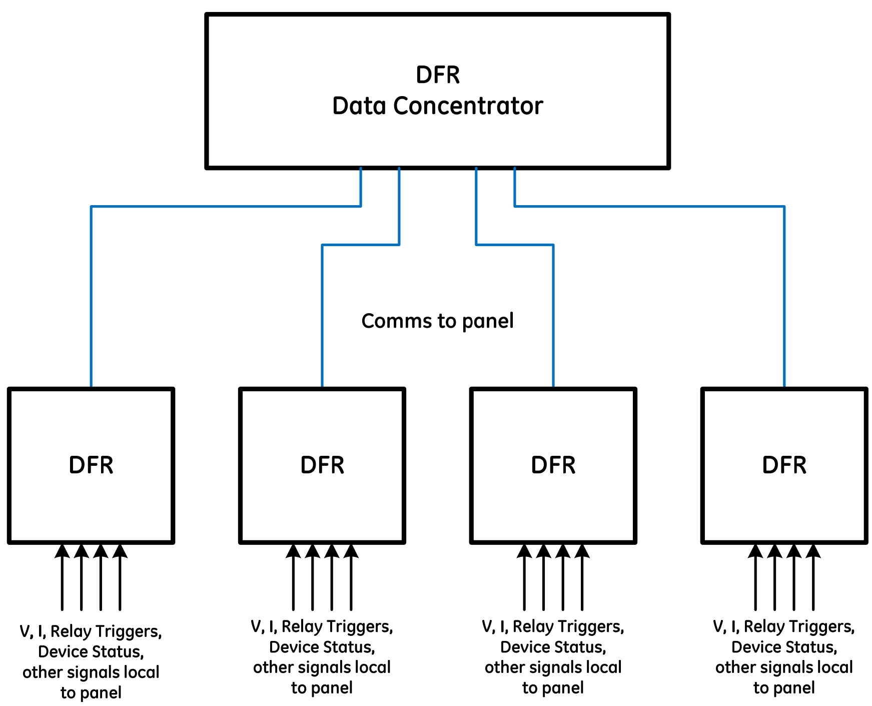


Figure 3: Distributed DFRs

Each one of these DFRs is an individual DFR, with the general capabilities of a larger DFR. These distributed DFRs therefore handle all data processing, triggering, and storage. The only difference is typically the number of input channels, and the ability to do local record storage. The DFR data concentrator is then responsible for collecting and synchronizing the records from each of the individual DFRs, and is also responsible for bulk data storage of DFR records. The communications between the DFR and the DFR data concentrator may be serial or digital. This communication is normally in a format proprietary to the equipment vendor, and the DFR data concentrator is specific to the same equipment vendor.

The advantage of distributed DFRs, once again, is in installation cost. Each DFR will be installed in relay panels, and the work of installation may be transferred to panel builder OEMs. Also, zone specific recordings are triggered and captured, which may allow more precise information to be collected.

The drawback to distributed DFRs is that this solution is still expensive, and may be more expensive in terms of material cost than the centralized DFR or distributed DAUs. The DFRs are more complex devices to maintain. The communications is still typically proprietary in format, limiting the flexibility of application. This also means the DFR data concentrator is a single purpose device, used only as part of the DFR system.

## 3.4. Distributed recording, or the virtual DFR

An obvious response to the challenges of DFR installation costs is to use the recording capabilities of other devices. Microprocessor-based protective relays include the ability to capture waveforms and sequence of events logs, and may include the ability to capture disturbance data. Distributed recording then, uses individual protective relays and recording meters to trigger and capture recordings. A centralized device or software then retrieves these recordings, coordinates and synchronizes recordings captured for the same power system event, and stores the data. In essence, this becomes a virtual DFR.

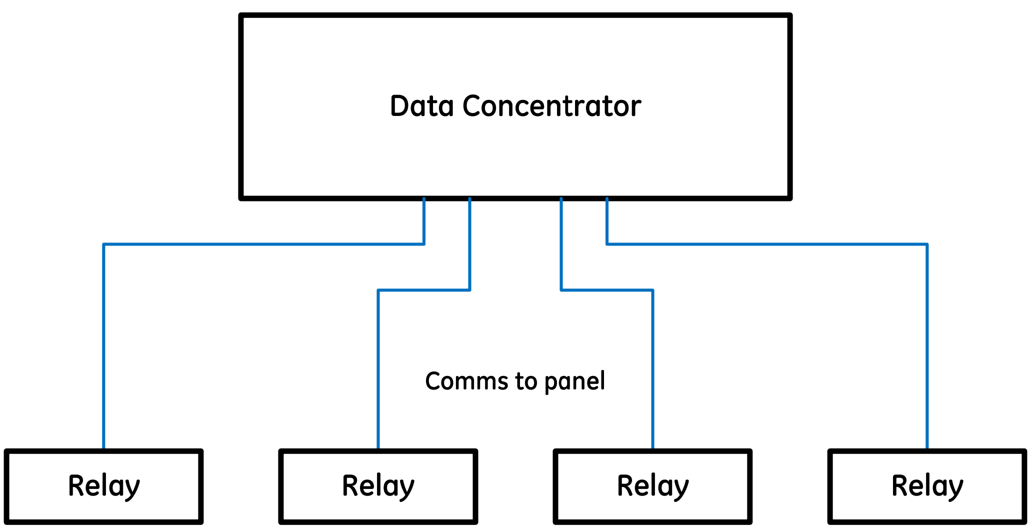


Figure 4: Distributed recording

The big advantage to distributed recording is that all the devices used for this already exist in the substation. Relays are installed for protection purposes; data concentrators are installed for substation automation and operations needs. The communications between relays and the data concentrator may be serial or digital communications, and normally use open protocols for the communications. The only tool that needs to be added is software that can collect the records from individual devices, and can combine and coordinate these records into a common format to make a station-wide recording.

The advantage to this virtual DFR is in installation costs. All the physical devices that make up the system are already installed, and are already wired to all the input channels required. In the case of protective relays, they are the native source of some data that is desirable to have in records, such as protection element operations. In addition, relays may record relay operating quantities, such as differential and restraint currents. Another advantage is operating costs: the individual devices are maintained as part of their routine functions, and no special maintenance is required.

However, the virtual DFR is a tradeoff between the application requirements for recording, and installation costs. Triggering is normally limited to protection element operation, and not generic analog quantities. Sampling rates in devices may be too low for good resolution, and the sampling rates of records may be different in different devices. Records are timestamped in each device, and the timestamping method may be different, resulting in difficulties in coordinating data. Some devices will use raw data for oscillography, while others may use filtered data. The collecting and coordinating data into one station-wide coherent view of an event may therefore take significant manual effort. Also, if no microprocessor-based relay exists for specific protection zones, these relays must be installed simply for recording purposes, forgoing some of the installation cost advantages.

## 3.5. Comparison of DFR types

Table 1 generally compares the capabilities of each type of DFR installation in terms of recording capabilities and installation costs and requirements. It is obvious that all types of installations meet the general requirements for recording. A dedicated DFR system will be better at recording than a virtual DFR system, but a virtual DFR system has a better installed cost.

The utility industry is split between the use of a dedicated DFR versus a virtual DFR system. There have been detailed discussions as to the benefits of each type.[5] At heart, this is a philosophical choice. The companies using a dedicated DFR have decided that they want an independent DFR, providing high quality data, using coordinated records, without being limited to the protection element triggers. These companies are willing to accept the extra cost for the use of dedicated DFRs.

Companies using virtual DFRs have decided that lower installation and maintenance costs are more important, and are willing to accept lower quality data, and the limitations of relying on multipurpose devices for recording. In truth, every company that uses dedicated DFRs still take advantage of the records contained in protective relays as part of event analysis.

However, the choice of a dedicated DFR versus a virtual DFR is nothing more than a discussion on managing analog signals: what's the best way to wire analog signals and capture the data. The focus is on the device as much as the application of recording. But this is the wrong focus. The focus should be on: how do I meet my requirements for recording data such that I can improve the operation of the power system?

Table 1: Comparison of DFR capabilities

| Functional Requirement | | Centralized | DAUs | Local DFRs | Virtual DFR |
|---|---|---|---|---|---|
| Channels | Analog | Y | Y | Y | Y |
| | Binary | Y | Y | Y | Y |
| | Calculated | Maybe | Maybe | Maybe | N: protection quantities |
| | Logic | Maybe | Maybe | Maybe | Y |
| Triggers | Analog | Free | Free | Free | Protection Element |
| | Binary | Free | Free | Free | Free |
| Records | Length | Long | Long | Long | Short / medium |
| | Sampling Rate | H | H | H | L / M |
| | Coordinated | Y | Y | Y: at DC | N: separate device |
| | Time Stamp | Y: record | Y: record | Y: record | Y: record |
| | Storage | H, native | H, native | H, at DC | L: separate device |
| Installation | Wiring | Lots | Lots | Lots | Lots |
| | Communications | None | Analog, serial, digital proprietary | Serial, digital proprietary | Serial, digital Open |
| | Cost | $$$$ | $$$ | $$$ | $$ |

## 4. IEC 61850 and functional modeling

IEC 61850 is an international standard focusing on communications networks and systems inside of substation. 61850 relies on functional modeling of the power system, and is a possible way to provide all the requirements of a DFR application, while minimizing the installation costs of having a dedicated DFR.

IEC 61850-5 [6] is an overall description of the Standard, and the essence is two basic concepts. The first is that you can "know" a piece of information: where it comes from, what it represents, and that you can trust this information. The second is that once you know a piece of information, you can share this piece of information using either a publish/subscribe model of data transmission, or a client/server model of data transmission.

## 4.1. Knowing information under IEC 61850

The heart of "knowing" a piece of information in 61850 is functional modeling of the power system. Every power system function, from protection element to metering to a circuit breaker, has its own functional model known as a "logical node". Each logical node describes common control services (where appropriate), data classes, and data attributes. Essentially, 61850 is object oriented modeling for the power system. Part 7 of the Standard provides the details of this functional modeling, with every logical node described in Part 7-4.[7]

The functional modeling of logical nodes leads to self-description of data. Every piece of data is transmitted along with the name of the device the produced the data, the instance of the logical node (the specific function) that produced the data, the data class (the type of data), and the data attribute (the actual data). So what is actually transmitted is Source Device::Logical Node::Data Class::Data Attribute::Data. Any device receiving this data will know everything about the data without knowing anything about, or having to configure a relationship to, the source device.

Beyond functional modeling and self-description is the concept of "trusting" data. It is mandatory in 61850 that every data attribute must provide three pieces of information: the actual data, a timestamp of when the data last changed state, and a quality flag that indicates the validity of the data. All three of these combine to indicate a level of trust in the data.

## 4.2. Sharing information under IEC 61850

IEC 61850 describes two basic methods for sharing information between devices: the publish/subscribe model, and the client/server model.

Publish/subscribe uses multicast transmission over Ethernet. A source device publishes data to the network using a multicast Ethernet frame. Any other device on the network may subscribe to this data, and use the data. This is best used for "right now" data: data that end devices need to make immediate use of. There is no handshaking, or direct acknowledgement of reception, between publishing and subscribing devices. Since these are standard Ethernet frames, everything takes place at the media layer of a network, and publishing uses MAC (media access control) addresses.

Client/server uses a two-party association model of transmission. Essentially, a client (the user of data) establishes a point-to-point connection through the network to the server (a source of data). This connection remains in place until released by either the client or the server. This is best used for "must trust" type communications, such as control services to operate circuit breakers. The client and server do establish a connection, and do acknowledge the receipt of information between the two.

## 4.3. IEC 61850 modeling example

Figure 5 is a simple DFR arrangement. Currents, voltages, and circuit breaker status are wired to both the protective relay for the zone, and a DFR. In addition, protection element trips are wired to the DFR as well.

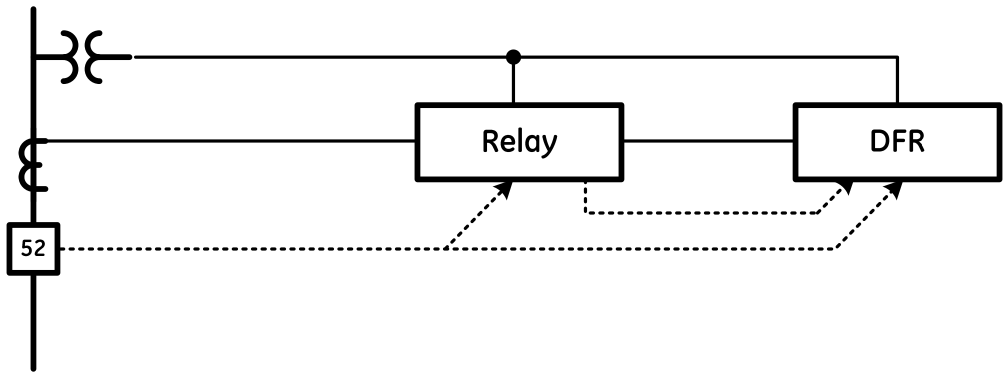


**Figure 5: Simple DFR arrangement**

Figure 6 illustrates this same arrangement under the functional modeling of logical nodes under IEC 61850.

- TVTR and TCTR are logical nodes that model the function of instrument transformers. In this case, they provide data in the form of “sampled values” (SVs), instantaneous digital samples of voltage (TVTR) and current (TCTR) waveforms.
- XCBR is a logical node that models the circuit breaker, including the position of the circuit breaker.
- PTRC is a logical node that models protection trip processing: essentially the output of every protection element in the relay.
- RDRE is the disturbance recording logical node, modeling all recording functions, including triggering, recording length among other attributes. Disturbance recording under IEC 61850 means all types of recording: fault recording (waveforms), sequence of events, and phasor data.

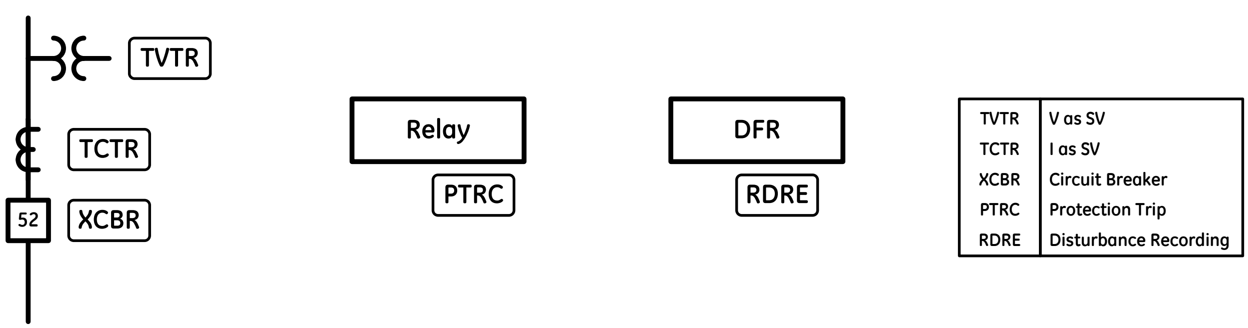


**Figure 6: Functional modeling of DFR arrangement**

These logical nodes are used to “know” the data: samples of currents and voltages, circuit breaker position, protection element trip. The important understanding is that the data from one logical node can be shared with any device on the system. This data includes quality flags and timestamping for trust of the data.

The data from TVTR, TCTR and XCBR will be shared with the relay, and this data, along with PTRC, will be shared with the DFR, as in Figure 7.

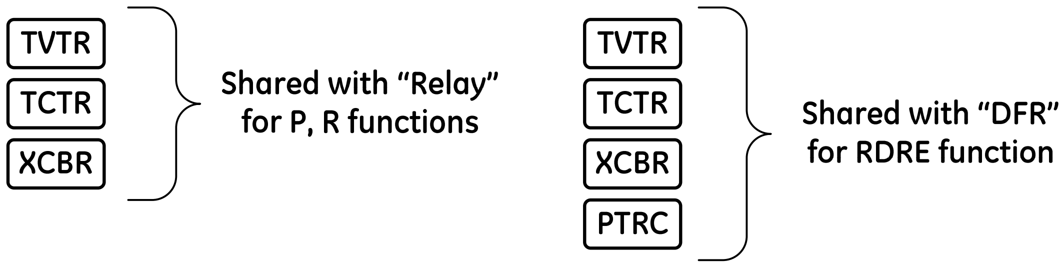


Figure 7: Sharing data for the DFR arrangement

## 4.4. Recording under IEC 61850

IEC 61850 includes a robust recording model that fully models the functions typically included in a DFR. The inputs to the RDRE logical node are two different logical nodes that represent analog and binary inputs channels. RADR is for analog input channels, and RBDR is for binary input channels.

A DFR is modeled as in Figure 8. Analog inputs, such as the sampled values of TVTR and TCTR are mapped to RADR. Binary inputs, such as circuit breaker position and protection trips, are mapped to RBDR. And there is an instance of RADR and RBDR for every input channel into the RDRE disturbance recording logical node.

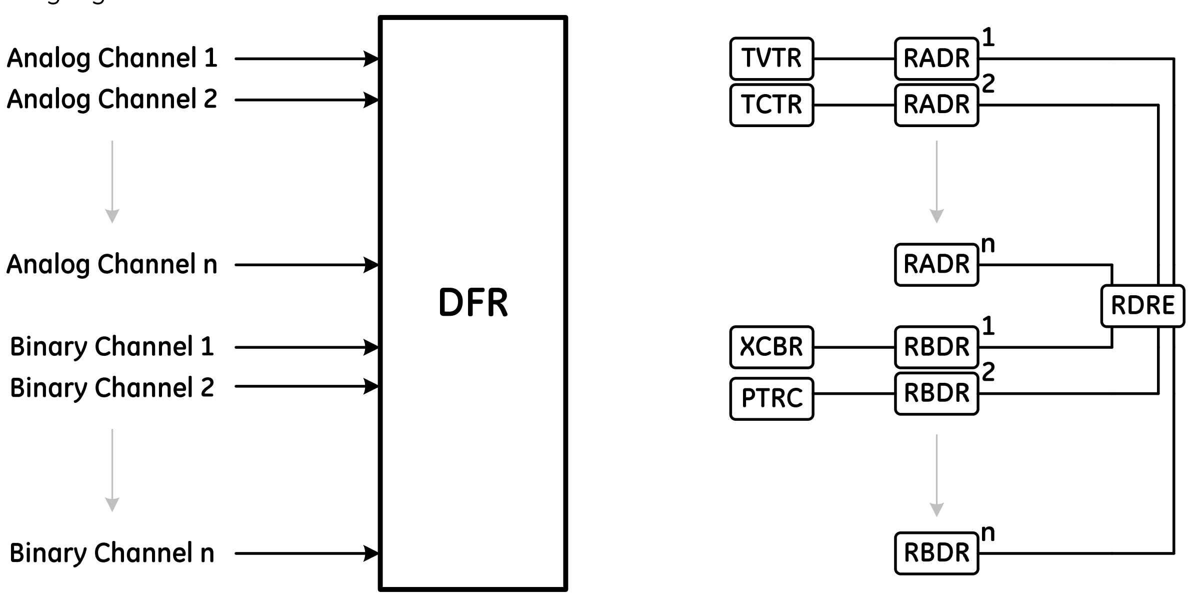


Figure 8: DFR modeled in 61850

## 4.5. Key message types for recording data

Recording data is "right now" data. You must publish this data (currents, voltages, equipment status) so the recording device can make immediate use of it. This means the use of the publish/subscribe model of transmission. There are two key messages types for publishing this data: GOOSE messages, and SV messages.

GOOSE standards for Generic Object Oriented Substation Event. A GOOSE message contains a dataset of items, that can include data attributes, data timestamps, and data quality flags. A GOOSE message is only published when one of the dataset items changes state. Reliability is provided by retransmitting the GOOSE message on a predefined schedule. The most usual items in a GOOSE message are Boolean data (along with timestamps and quality) such as circuit breaker position and protection element trips. GOOSE is more fully described in Part 8 of the IEC 61850 Standard.[8]

SV messages are sampled value messages, that contain digital samples of waveforms, along with some description of sampling rates and time synchronization status. The digital samples are the key data attributes produced from TVTR and TCTR logical nodes. SV messages are more fully described in Part 9-2 of the IEC 61850 Standard.[9]

## 4.6. Process bus

Process bus is using the capabilities of IEC 61850 to provide distributed I/O for protection and control. Devices are placed in the switchyard at primary equipment like instrument transformers and circuit breakers to digitize key data like currents, voltages, and equipment status. This data is published to a network using GOOSE and SV messages. Any device connected to the network, such as protective relays, can subscribe to and make use of this data.

There are three basic types of devices that publish data for process bus: merging units (MUs), remote I/O modules (RIOs), and process interface units (PIUs). Figure 9 describes each of these devices. An MU publishes only analog data in SV messages. A RIO publishes only equipment status data in GOOSE messages. A PIU publishes both analog and status data in both SV and GOOSE messages. All fill the same role of digitizing analog data at the primary equipment source.

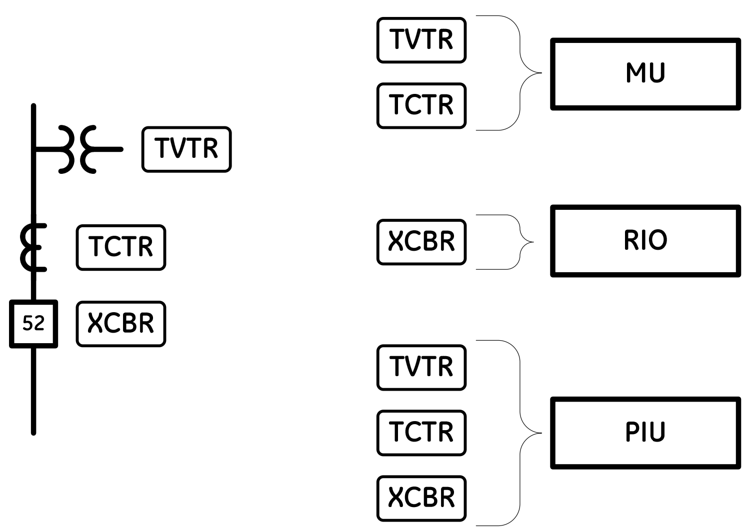


Figure 9: Process bus devices

The devices of Figure 9 show the data for the simple model arrangement of Figure 6. However, there is much more data that may be required for recording purposes.  IEC 61850 defines logical nodes by type of equipment or high level function, by defining groups of related logical nodes. The first letter of the logical node name identifies which group this logical node is part of. The data needed from these groups identify which type of I/O device can be the source of this data, as in Figure 10.

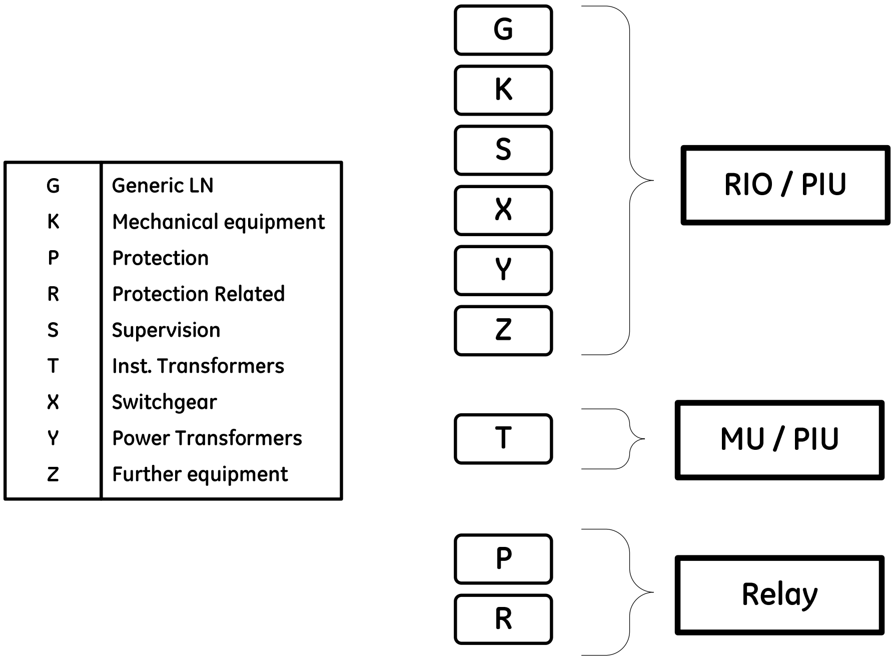


Figure 10: Possible source devices for data

A typical process bus system is conceptually represented in Figure 11. Data acquisition devices such as PIUs publishing data (SV and GOOSE messages) to the network. Protective relays subscribe to this data, and issue control actions via GOOSE messages back to PIUs.

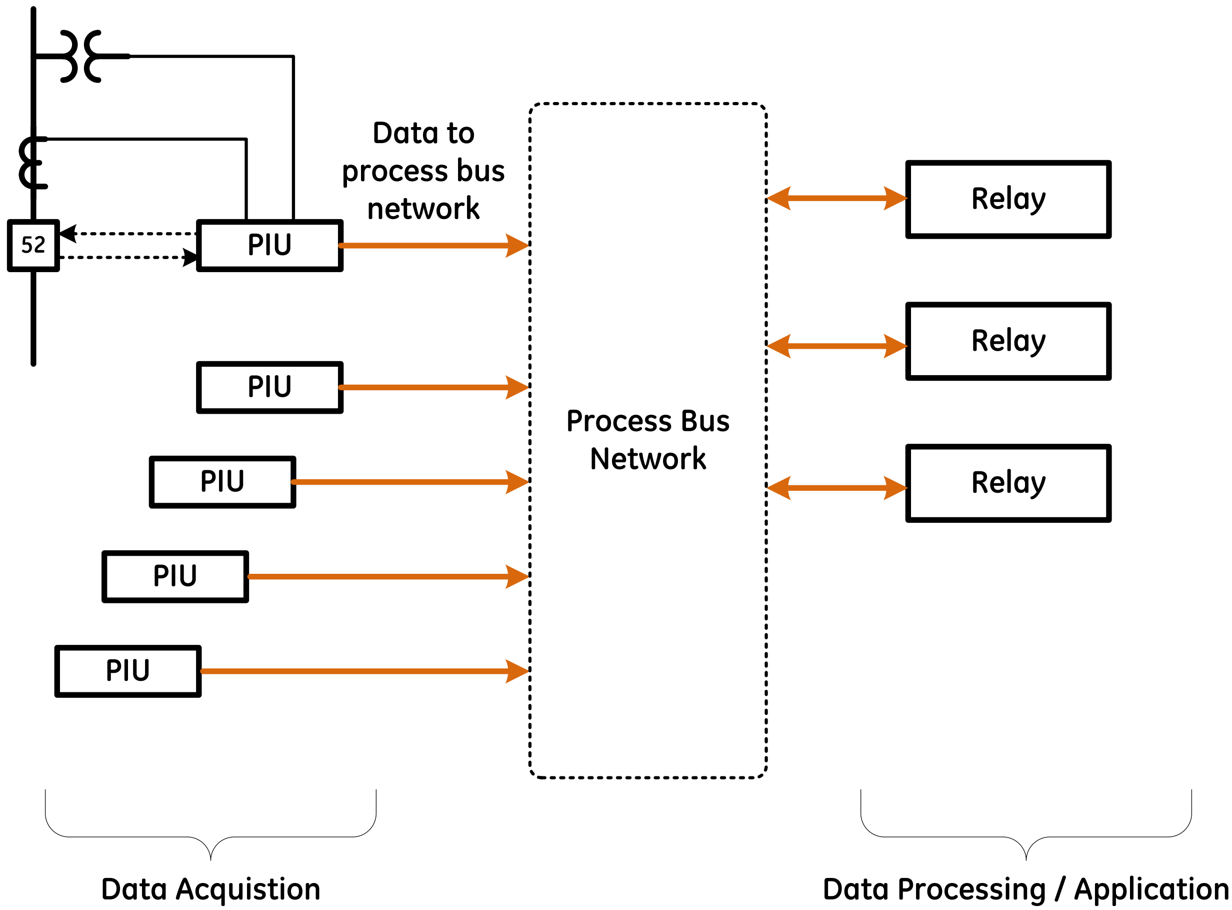


Figure 11: Process bus system

## 5. Process Bus and the DFR function

It is simple to look at the sample process bus system of Figure 11, understand the functional modeling of IEC 61850, and quickly see the virtual DFR system of Figure 4. Therefore, relays must include the RDRE function to do native waveform recording. This results in an architecture similar to Figure 12. Each relay subscribes to GOOSE and SV messages from PIUs containing self-described, timestamped data. Each relay includes input channels (RADR and RBDR) to link the appropriate data into the RDRE recording function. The RDRE data is collected at a data concentrator, using the RDRS function, a logical node intended for record handling of recording data at the substation or system level.

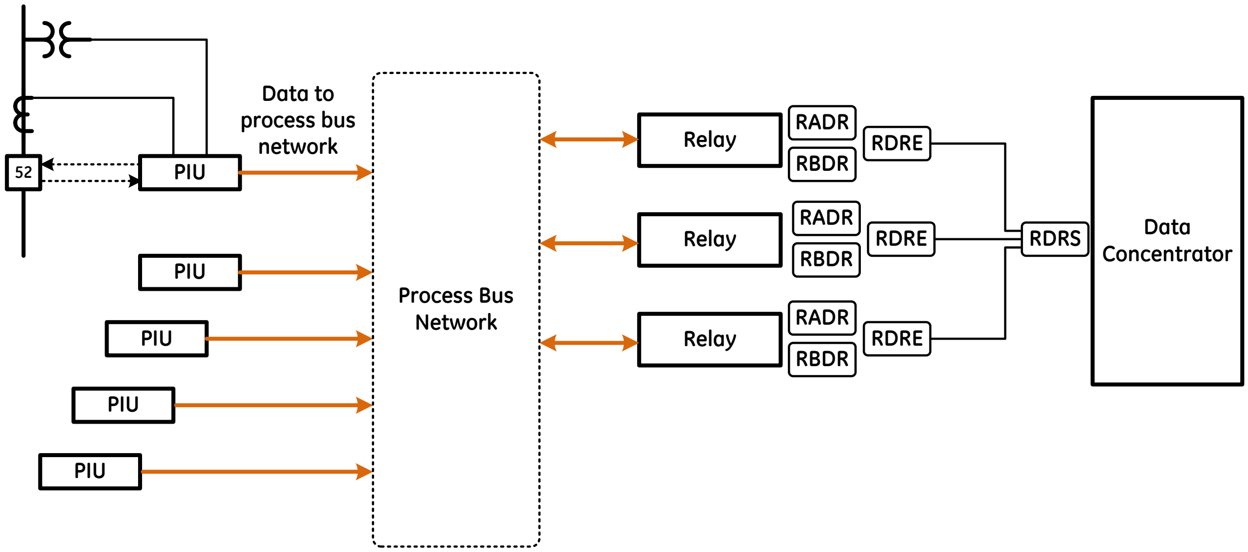


Figure 12: Virtual recording using process bus

This is therefore the distributed or virtual DFR, using 61850 for data acquisition, transmission, functionality, and record handling. 61850 allows you to, or drives you to, think in terms of functions and applications, as opposed to specific devices. The reality, however, is that 61850 functionality is implemented in specific devices, and the application is limited to the capabilities of the individual device.

The process-bus based recording system of Figure 12 is no different in general concept than the virtual DFR. The recording capabilities will be determined by the limits of the triggers, sampling rates, record lengths, and data storage of the individual relays. The data concentrator will still use software to combine records from different devices into a common station wide record for analysis. Therefore, this system still carries all of the advantages and disadvantages of the virtual DFR. However, the one plus to this system is that all data carries its own timestamp. So synchronizing data is easier. It is synchronizing the based on timestamps of the actual data, as opposed to synchronizing based on timestamps of records produced by individual devices.

## 5.1. Dedicated DFR under IEC 61850

IEC 61850 is a powerful concept: the focus is on defining needed functionality, as opposed to thinking in terms of devices. The challenge is that 61850 functionality is device dependent: how the function is actually implemented is determined by the manufacturer of a specific device. There is still the concern about how to trigger, how long a record is available, what type of records and data is available, and data storage requirements.  Therefore, the distributed DFR under IEC 61850 is no different in terms of performance than the distributed DFR before 61850, other than the advantage of timestamped data.

However, IEC 61850 does provide an advantage to the dedicated DFR. Physical installation cost of a dedicated, centralized DFR is basically only the material cost of the DFR, and the cost to configure. There is no wiring cost, as the installation is simply mount the DFR in a cabinet, connect power, and connect to the network to start acquiring data. A dedicated DFR system using process bus is illustrated in Figure 13.

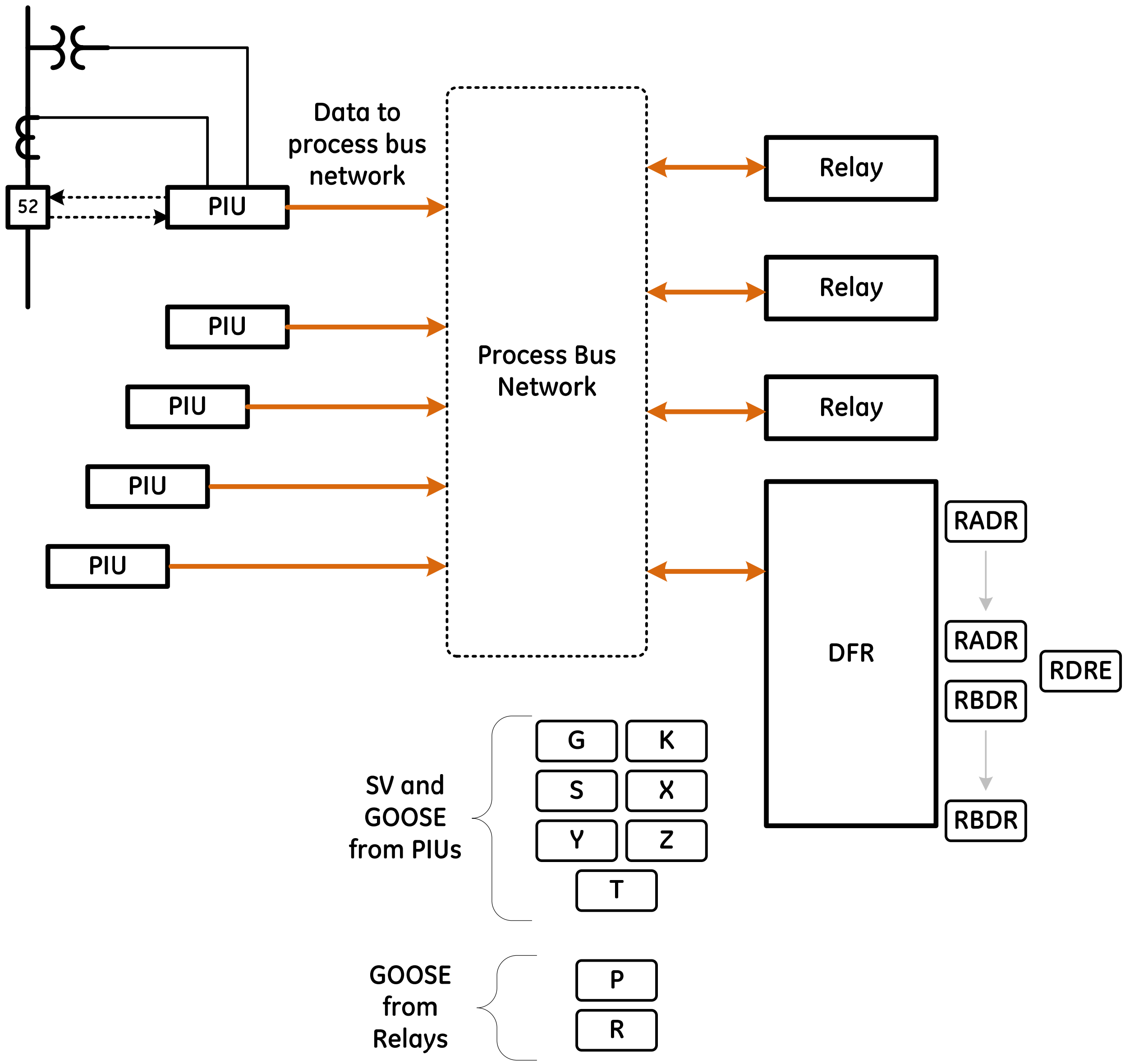


Figure 13: Dedicated DFR using process bus

The dedicated DFR in this case is a true DFR implementing 61850. Source data comes from SV and GOOSE messages published by MUs, RIOs, PIUs, and other devices like relays. The DFR includes all the capabilities of a modern DFR, like freely assignable analog channel triggers, configurable record length, long records, records with large number of channels, massive data storage, and the like.

Note that this DFR could be a multipurpose data concentrator that implements all the recording functions and triggers as in a regular DFR, because the device is potentially free of hardwired inputs for data acquisition. However, in the near future, it is likely to remain a dedicated recording device.

## 5.2. Practical considerations for the dedicated DFR under IEC 61850

The biggest practical challenge for a dedicated DFR using process bus as inputs is having a device that operates as a full-featured DFR and also has the ability to accept data from SV and GOOSE messages. Such devices are already available on the market.

A second practical challenge is in real-world installation. Many installations of process bus are in existing substations, where new facilities will use process bus devices to provide data, but most of the substation uses existing devices hard-wired to analog signals. Therefore, a dedicated DFR needs to be designed to accept data as process bus communications using GOOSE and SV messages, while still have the ability to accept analog measurements in some way. Such a system in shown in Figure 14.

However, there is a technical challenge for a hybrid DFR that accepts both SV messages and standard wired analog inputs: which is time synchronization of the data. Sampled values captured by MUs and PIUs contain natively time stamped data. Analog data captured directly by the DFR itself normally is not natively timestamped, as all channels are captured simultaneously, and any resulting record is timestamped. The challenge is that of time delay: capturing SV data results in a communications delay to the DFR unit that can be in the millisecond range. This will be after the hardwired data has been captured. The DFR has to account for these time differences in the basic hardware and firmware design, to ensure all data is coherently time aligned. In a well-designed DFR, configuring the analog input channel triggers, or the binary input triggers, should be identical for both SV and hardwired analog channels, and GOOSE and hardwired binary channels.

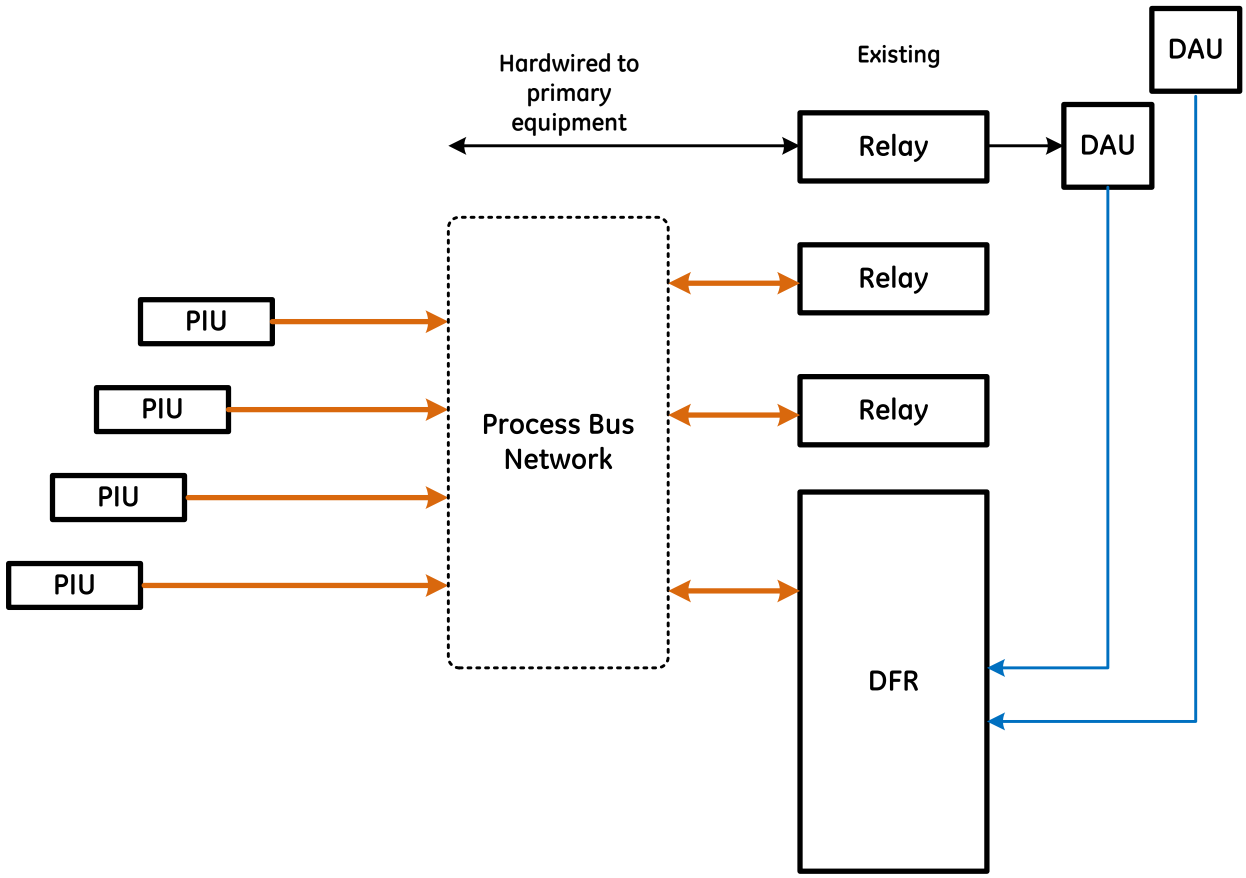


Figure 14: Hybrid Dedicated DFR

The design of a dedicated DFR that supports hybrid inputs obviously impacts the physical installation of the unit. The unit could be a centralized DFR that contains hundreds of physical input channels. Or the unit could accept only SV and GOOSE messages, requiring the installation of PIUs at primary equipment. The most convenient method may to use a DFR that supports both process bus, and the distributed DAU architecture. This allows the installation of simple DAU units in relay panels to acquire analog data that is not coming through MUs, RIOs, and PIUs. In this instance, analog data acquired through SVs should be configured identically as traditional analog channels, as in Figure 15, and digital channels acquired through GOOSE messaging should be configured identically to traditional digital channels, as in Figure 16.

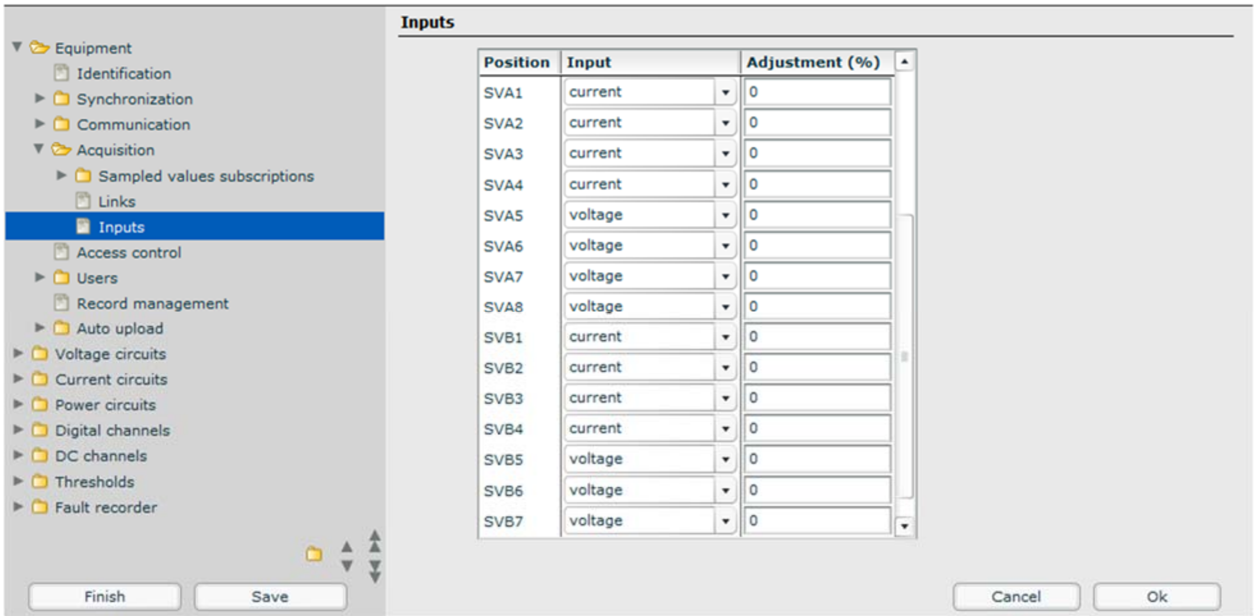


Figure 15: SV analog channel configuration

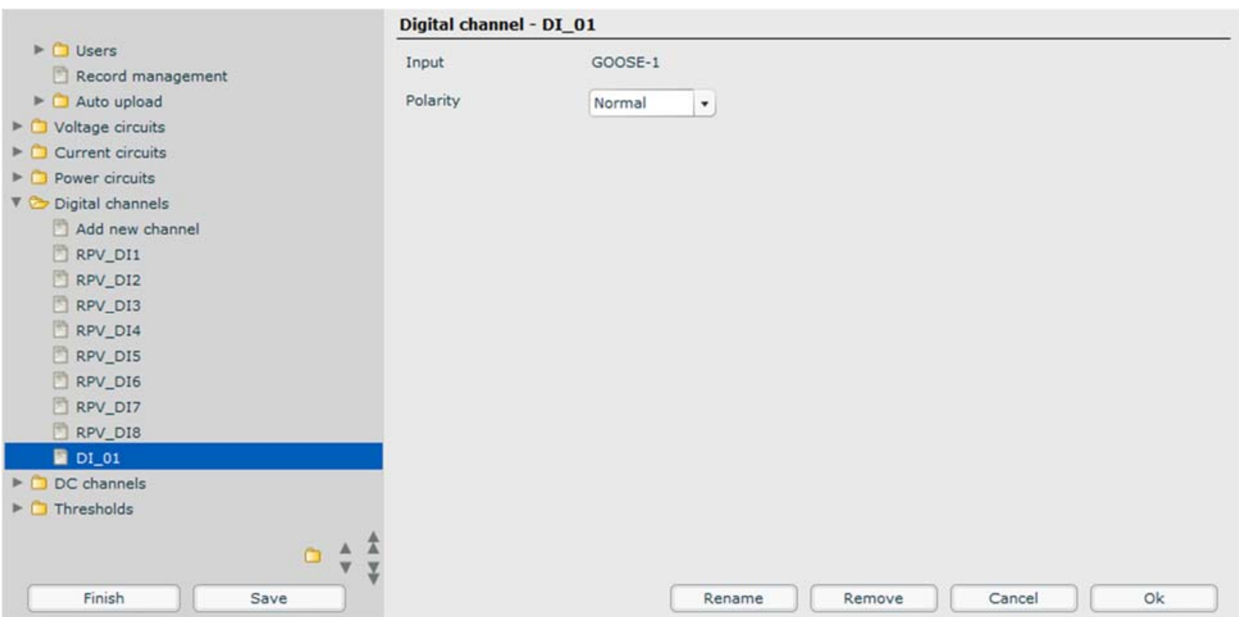


Figure 16: GOOSE digital channel configuration

## 5.3. Practical Installations

There have been several actual installations of dedicated DFR units using process bus. In both cases, the DFR acquired data from SV messages and GOOSE messages over process bus, and also from traditional DAUs hardwired to instrument transformers and primary equipment.

The first project is at Palhoça Substation, a 138kV substation operated by Electrosul in Brazil. This project is a pilot project for process bus and IEC 61850 in general. The goal of this project is to prove the concept of process bus, including tripping time of protection, performance of the virtual DFR using sampled values, and improved safety for protective relaying installations. The project scope was simply one line bay, and a complete process bus network. The general concept of the installation is shown in Figure 17.

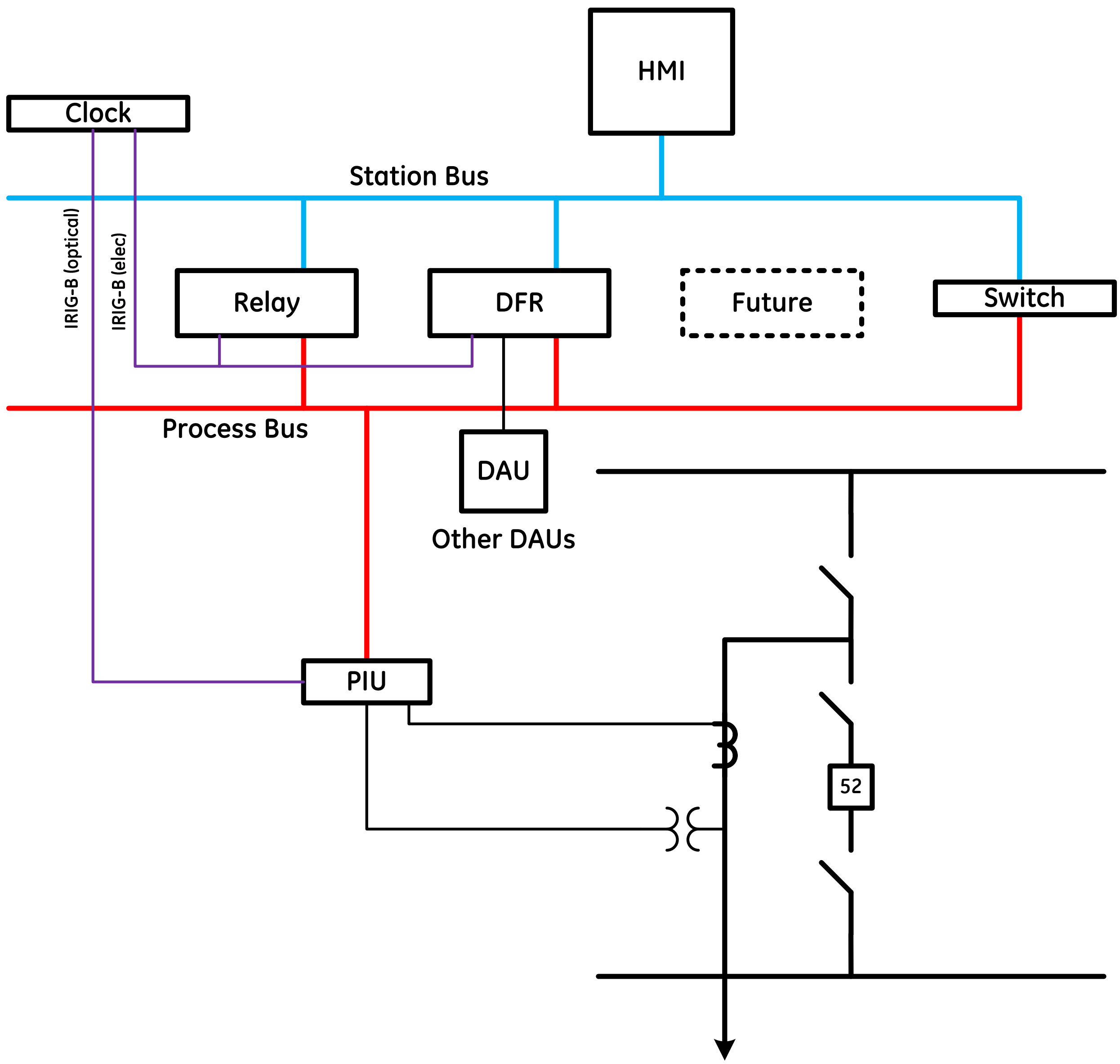


Figure 17: Electrosul Palhoça Substation dedicated DFR over process bus

The second project is at Embu-Guaça Substation, operated by CTEEP in Brazil. This is also a pilot project for process bus, applied on a 13.8kV distribution feeder. The goals of this project are similar to that of the Palhoça project, including verifying performance and measurement of analog signals by traditional methods and by sampled values. This project is a dedicated pilot project, that involved mounting a PIU and traditional DAU in switchyard kiosk, and building a dedicated equipment panel, as shown in the one line of Figure 18.

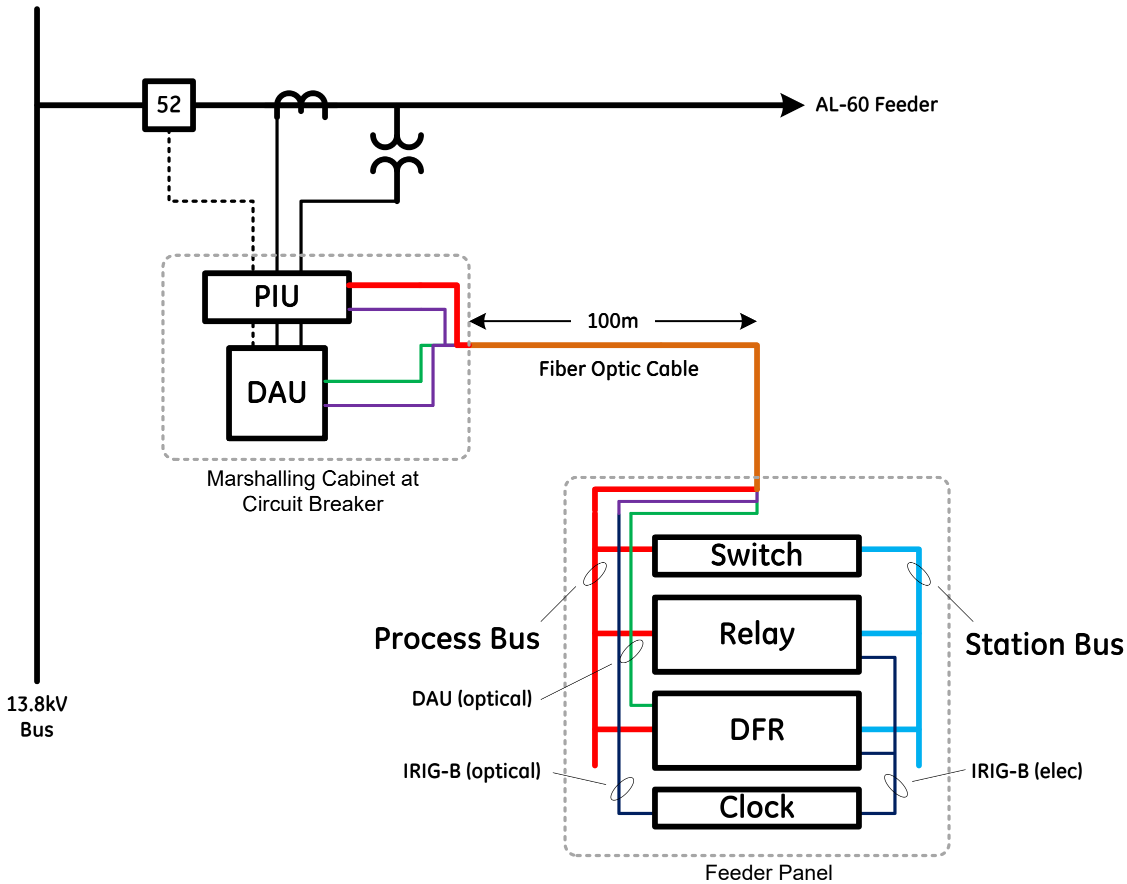


Figure 18: CTEEP Embu-Guaça Substation dedicated DFR over process bus

One of the key learning goals of this project is to prove that sampled value measurements and traditional analog measurements can co-exist in the same device. This goal has been proven during field experience of this project. Figure 19 is an example capture of data, showing identical performance of the SV and conventional (DAU acquired) data.

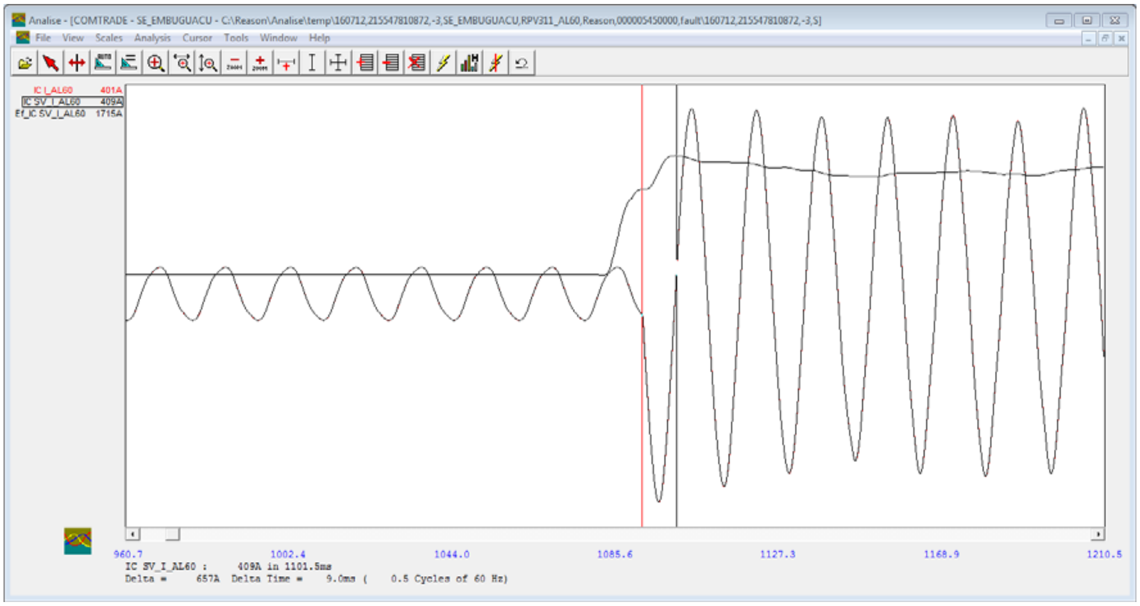


**Figure 19: Equivalence between conventional analog signals and SV**

## 5.4. Other possible applications of a dedicated DFR

A dedicated DFR using process bus, like any centralized dedicated DFR, has more possible applications, as coherent real time data is readily available. Two of the applications are as a phasor measurement unit (PMU) and as an advanced fault locator.

DFRs typically capture phasor data to meet requirements for dynamic disturbance recording. This can be simple analog phasor data, but it is also possible to capture this data as synchrophasors. By streaming this data using C37.118.2[10] compliant data streams, the DFR can also act as a PMU. Because a DFR has as many as 64 analog channels, it is possible for a centralized DFR to act as multiple PMUs in one device, streaming multiple synchrophasor data streams. Timestamping the raw data through process bus helps simplify this process.

Waveform data is used as the key input to fault location algorithms. Though relays typically perform this function natively, DFRs can also perform fault location calculations, but with more data from more sources to help finetune the fault location. Some DFRs have the capability to use traveling waves to perform fault locating, or TWFL. However, TWFL is very difficult over process bus. TWFL algorithms require high frequency sampling of voltage or current data. This high frequency sampling is not currently supported by any MU or PIU commercially available, and leads to bandwidth concerns on the process bus network. However, a hybrid DFR can use process bus for most signals, and a dedicated DAU for traveling wave capture on critical lines to achieve this goal.

# 6. Conclusions

The need for DFRs, or more correctly, DFR data, is well understood. Fault recordings, sequence of event logs, and disturbance recording can help understand how the power system, along with the primary and secondary equipment that make up the power system, actually operates. The role of the

DFR is to make this non-operational data available as data files to various groups inside the utility. The DFR is therefore a useful diagnostic tool for utilities.

The cost of installation has driven utilities to move away from a dedicated DFR to a virtual DFR using microprocessor-based protective relays as the source for DFR data. This reduces the quality of DFR data, slightly, to improve installation costs.

However, the introduction of process bus for data acquisition through IEC 61850 changes the calculations. A dedicated DFR that accepts sampled values and GOOSE messages from process bus as inputs can be the best of both worlds. A quality, mission-specific recording device with a very limited cost of installation. This can bring about the return of the dedicated DFR.

## 7. References


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[10] *“IEEE Standard for Synchrophasor Data Transfer for Power Systems”*, IEEE Std. C37.118.2-2011, The Institute of Electrical and Electronic Engineers, Inc., New York, NY, 2011.


## Biographies

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