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Completing the IEC 61850 substation – the need for metering

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SUMMARY

Undoubtedly substation designs have to implement new technologies to maintain a cost effective means to design, construct and maintain substations in an economic way.

One of the technologies that is certainly making an impact on the overall substation design is IEC 61850. Initially seen as mainly a protection and/or SCADA engineering process to configure Intelligent Electronic Devices (IEDs) to communicate over a substation LAN, it is rapidly gaining traction in other "information domains" within the substation and opening up the potential for far more wide-reaching integration of condition monitoring information about the substation.

The growth in adoption is likely to take a significant jump with the arrival of a number of suppliers offering Sampled Value Merging Units according to the requirements of IEC 61850-9-2, both for conventional CT/VT and non-conventional sensors.

The business case for IEC 61850-9-2 Sampled Value deployment is the significant reduction in substation engineering and the number of cables to be installed in the substation associated with the CT/VT wiring. No longer will it be necessary to run hundreds of cores of wiring and the many marshalling points and isolating links for each bay of primary plant for the CT and VT secondary connections, but rather just a LAN connection to the sensors. This in turns leads to smaller cable trenches and many other benefits in testing, commissioning and indeed operation, maintenance as well as refurbishment and augmentations.

Although IEC 61850-9-2 was released in 2004 along with IEC 61850-8-1 defining GOOSE and MMS, there has been relatively few implementations of Sampled Values. Apart from the initial caution associated with increasing reliance on LAN technologies, this slow adoption was mainly due to the very limited number of commercial Merging Units available. This started to change in 2012/13 to the point where there are now several suppliers of "proper" IEC 61850-9-2 Merging Units.

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The availability of these Merging Units will certainly introduce significant changes to the deployment of the protection and SCADA equipment.

However, one area that seems to be lagging in its move to Sampled Value adoption is the revenue metering for bulk supply points.

"Grid" metering of course demands its own set of CT and possibly VT cores in order to provide the required high accuracy of the overall metering system well below rated current. Conventional systems simply involved certification of the CT, VTs and meters as separate pieces of equipment.

In order to avoid severe limitation of the business case for IEC 61850 deployment, it is necessary to ensure that the substation is not left with a LAN replacing the protection related CT/VT wring but still hundreds of wiring associated with metering cores. This in itself demands a rethink on the Standards pertaining to a "stand alone" conventional meter defined in IEC 62053-22.

The move to Sampled Values now segregates the single meter device into a combination of the Merging Unit, the LAN switches and topology, the time synchronisation source and finally the metering calculation function IED.

This paper therefore raises some of the issues reflecting a particular utilities first foray into investigation of a suitable metering deployment for IEC 61850-9-2.

KEYWORDS

Digital Substation, Revenue Metering, IEC 61850, IEC 61850-9-2, IEC 60253-22

1. **Why are <u>revenue metering</u> IEDs with Sampled Value inputs necessary?**

From the outset, IEC 61850-9-2 Ed1 in 2004 provided the mechanism for transmission of Sampled Values over the LAN. At the time this was restricted to samples represented by only the two IEC 61850-7-4 Ed1 Logical Nodes: current (TCTR) and voltage (TVTR). IEC 61850-9-2LE was a "companion guide" issued by the UCA International Users Group that defined various aspects such as the sampling rate for CT and VT applications associated with substations. IEC 61850-9-2LE is soon to be incorporated into the general sensor standards IEC 61869.

However there has been very limited take up of Sampled Values until relatively recently – simply due to the limited number of suppliers offering fully interoperable Merging Units as sources of these Sampled Values. However since 2014 there has been a significant increase such that now there are some half dozen or more "main stream" vendors providing Merging Units that can support protection IEDs based on IEC 61850-9-2LE inputs.

If we consider IEC 61850 as a mechanisms for engineering the configuration of devices to communicate over a LAN [14], at first glance a <u>revenue</u> metering device has very limited communications requirements – basically to transmit data back to the billing control facility. For the moment we will ignore the message structure of the communication protocol back to the billing control facility and concentrate on the requirements for integration of the meter into the substation secondary system.

Noting the second paragraph of Chapter 1 of CIGRE Technical Brochure 246 [13], TransGrid started a project to reduce the cost of the overall secondary systems implementations for new green field sites and replacements to existing substations secondary systems, this was driven by the need to refurbish many substations that were built in the late 1950's and early 1960's. Replacement of the substations as "like-for-like" wire-based systems would involve "millions of dollars" in secondary system drawings alone, apart from a significant work load in upgrading systems, devices and functions as well as construction, commissioning and cutover from the existing (very old) systems.

A significant part of TransGrid's general deliberations on technology changes has been the adoption of "change management" principles for engagement across the entire organisation in approving the concepts. Whilst this itself took some time, it has established an enterprise-wide commitment, rather than just a niche specialist group, to the strategy.

TransGrid's business case assessment identified potential **cost reductions in excess of 15%** could be achieved by using IEC 61850 technology basis in new secondary system projects. The key to the major cost savings is the removal of all copper cables and the associated infrastructure that they require, that is implementation of a complete "Digital Substation" which includes protection, control and metering.

The Proof of Concept development phase in fact identified the savings would indeed be even higher using innovative solutions to many practical/physical problems. The project engaged the equipment vendors and searched the market for equipment in late 2014 and looked at many different options. The deployment option chosen was to implement full "station bus" and "process bus" [16], in particular with the adoption of IEC 61850 9-2 Sampled Values for both protection and revenue metering devices.

Removal of wires implies replacement by LAN based systems where devices are configured to communicate [14], which in turn implies both communication and engineering interoperability. It is to note that the Standard prescribes an engineering process (tools and files) in IEC 61850-6 <u>followed</u> by the semantic data model definitions as IEC 61850-7-3 Common Data Classes and IEC 61850-7-4 Logical Nodes, and only then defining the real time communications over the LAN (protocols) in IEC 61850-8-1 and -9-2. This is the meaning of "IEC 61850 is no *mere* protocol"!

However, it is ironic that significant engineering time and cost reductions and minimisation of human error that have been obtained in the protection and SCADA systems, but the revenue metering systems as the revenue source for the industry remains constrained by these old conventional wire based requirements.

Whilst "basic" deployment is feasible, TransGrid's investigations indicates there is a combination of issues relating to the technical case for broader deployment of IEC 61850 based revenue metering. One is simply that there is a very limited number of vendors providing IEC 61850-9-2 input meters. In any case these devices have some (presently) limited functionality in respect of certain operating and security aspects required for revenue metering deployment in high/extra high voltage substations. The issue of revenue metering has been raised in CIGRE even in 2014 [4] so it is hoped this paper may assist as a further catalyst in the industry to resolve the last few issues.

The design of the conventional substation secondary system infrastructure is clearly heavily reliant on wires as seen in Figure 1 as a simplified diagram which may be duplicated as "X and Y" or "Main 1 and Main 2" in some applications.

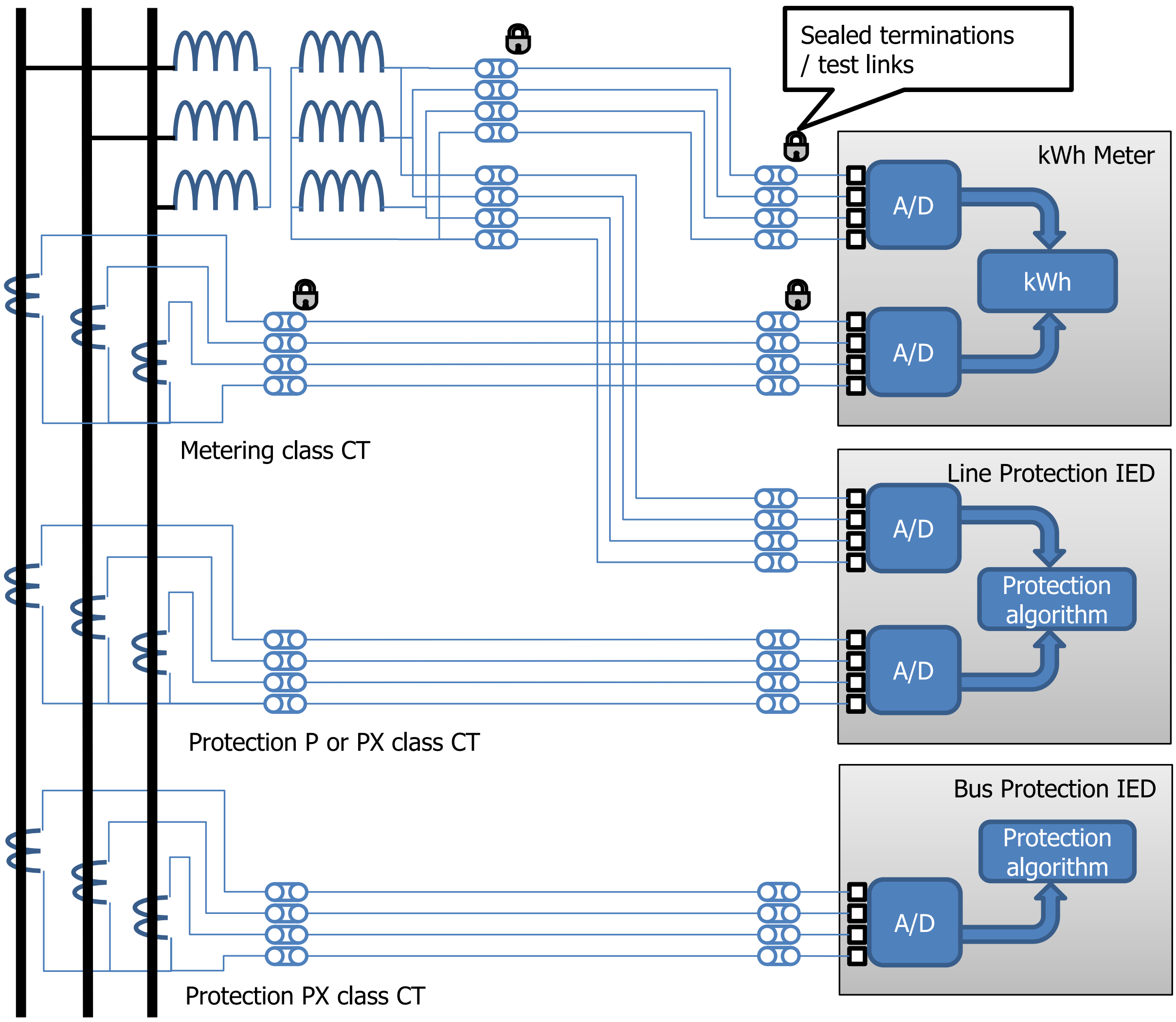

Figure 1 Simplified typical wire-based single feeder CT/VT wiring arrangements

Certainly the Australian National Electricity Rules have requirements on redundancy of the protection system, notably with the inclusion of the phrase:

> *"with any single protection element (including any communications facility upon which the protection system depends) out of service".*

Furthermore the Australian Energy Market Operator's Standard for Power System Data Communication dealing with the SCADA system requires redundancy considerations including:

> *"the equipment that provides the analogue to digital conversion function"*

The Australian National Electricity Rules develops the concept of duplication as "check metering" in Chapter 7 section S7.2.4.:

> *(b) A check metering installation involves either:*
>
> *(1) the provision of a separate metering installation using separate current transformer cores and separately fused voltage transformer secondary circuits, preferably from separate secondary windings:*
>
> *(f) Check metering installations may be supplied from secondary circuits used for other purposes and may have a lower level of accuracy than the metering installation, but must not exceed twice the level prescribed for the metering installation.*

As single or duplicated systems, there is considerable engineering, construction and commissioning effort associated with wire-based systems.

The benefits of IEC 61850 are derived from integrating all the IEDs into a structured engineering process based on the six System Configuration files defined in IEC 61850-6. The consequence of that is a physical deployment with no wires, apart from the auxiliary power supply to the devices and of course their Ethernet LAN connections.

Clearly retaining wire based engineering and deployment *just* for the revenue metering severely undermines these benefits for the total cost of the project. Furthermore it constrains the physical deployment and forces two different operating procedures with special drawings, documentation, handling, mounting and configuration engineering. It is therefore imperative to have a coherent engineering and physical connection regime for all IEDs.

Setting aside the many benefits in their own right of any other degrees of adoption of IEC 61850 technology, implementation of IEC 61850 9-2LE can deliver substantial cost reductions due to the removal of civil works associated with installation (and removal) of hundreds/thousands of copper cables and their many terminations associated with CT/VT circuits. Even more so with the full "process bus" [16] including digitising all inputs and outputs in the High Voltage Yard associated with switchgear position and control using IEC 61850-8-1 GOOSE and MMS. The amount of engineering, drawings, verification, commissioning and testing is dramatically reduced being replaced with the infamous "single source of truth" IEC 61850-6 SCD file [17]. A recently completed CIGRE Technical Brochure 628 [18] considers the life cycle documentation requirements associated with IEC 61850 based systems.

Other benefits include smaller buildings, almost zero inter-panel wiring, and small cable entries to buildings. A typical TransGrid conventional wire-based secondary system protection panel arrangement inside the control building could occupy some eight metres or more of panels and many yard cable marshalling kiosks (Figure 2). The optimised TransGrid IEC 61850 deployment has been reduced to just two panels (< two metres) inside the control building!

Cable trenching and cable management is a significant issue in the design of any substation, even in small substations as shown below. The number of cables – often multicore – that need to be run and terminated creates a significant footprint of trenches and of course commissioning requirements. Clearly replacing wire based signal transmission with either direct buried fibre cables (as used in a NZ utility) or if necessary as multifibre conduits offers a significant advantage in substation land use apart from huge reductions in terminations and commissioning.

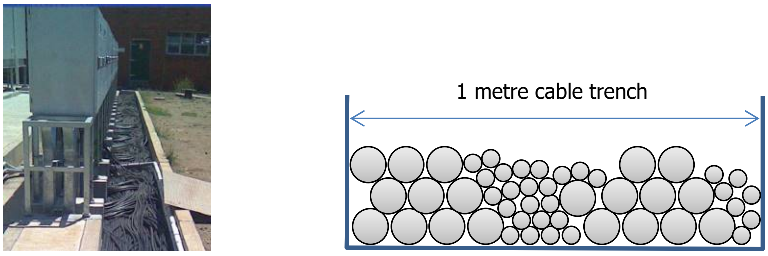

Figure 2 Conventional wire-based secondary system cable trenches

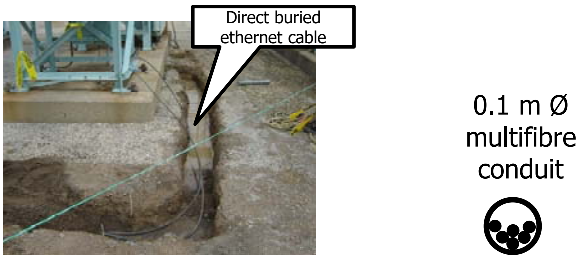

Figure 3 Fibre based yard wiring - direct buried or conduit

A consequential operational benefit relates to situations where Utilities have sometimes suffered cable trench fires in substation yards for various reasons, including rodents eating through cables and causing short circuits. Conventional trenching contains hundreds/thousands of individual wires which take months to reinstall and recommission. With a LAN fibre based system, even whilst the fire trucks are rolling in to the substation, a new drum of fibre can be rolled out on the ground around the other half of the substation and recommissioned in a matter of hours and restoring complete substation functionality.

2. “Conventional” revenue metering

This paper is primarily focused on major substation automation systems involving so-called bulk supply point revenue metering and specifically does not address the general industrial, commercial or domestic “end-consumer” revenue metering.

The bulk supply revenue meters are often deployed at interconnection points such as generators connecting to the grid or the interconnection points between transmission and distribution utilities. Equally very large individual industrial consumers may require specialised metering simply due to the large revenues associated with even small measuring inaccuracies and/or the site power system is effectively a private distribution grid with some degree of sophistication in its electrical power management and automation systems.

A “conventional” stand-alone meter device has current and voltage inputs which are used by Analog-to-Digital converters and then calculated into the kWh values as shown in Figure 1. Traditionally it has only been these kWh readings that have been needed for billing purposes, with modern tariff structures using more complex arrays of information from the meter. However the communication process was easily provided – perhaps even as a dial up modem associated with the meter which was polled by a meter reading software (typically in Australia using MV-90 protocol and software system) on a set schedule.

3. Where does metering fit into IEC 61850, and vice-versa?

The first release of the main parts of IEC 61850 in 2002 – 2004 were under the title “Communication networks and systems in substations”. In many respects the Standard was seen to be mainly (only) related to the protection and/or SCADA disciplines.

In 2008, certain Parts of the Standard began to be released as Edition 2 under a new title “*Communication networks and systems for power utility automation*”. This subtle change helps to highlight that the Standard is focused on the engineering processes and mechanisms to configure devices to communicate information about the power system from one location (device) to another, and hence facilitate the creation and operation of automation functions.

The expansion of the Standard as Edition 2 of certain Parts is seen in particular in the "T" group Logical Nodes under IEC 61850-7-4 Edition 1 had just two LNs for modelling Sampled Value sources for current transformers (TCTR) and voltage transformers (TVTR). Edition 2 was expanded to over 20 Logical Nodes encompassing a range of physical quantity measurements from temperature and pressure to position and vibration.

Equally, the "D" group of LNs refer to a wide ranging group of Distributed Energy Resources as another example of the use of IEC 61850 for any engineering process, semantic and communication mechanism for utility automation systems in general.

However right from the very start, IEC 61850-7-4 Edition 1 included Logical Nodes for metering – MMXU for basic RMS measurement values (such as Amps, Volts, Frequency, Watts, VArs) and MMTR for derived metering values such as Watt-hours. Logical Node MHAR and MSQI deal with harmonics and sequence components. These Logical Nodes have served to support the general SCADA system requirements at the so-called "station bus" level using the IEC 61850-8-1 MMS commands and reporting.

As referenced in [12], [13] and [14] the first benefits of IEC 61850 lie in having a set of coherent IEC 61850-6 System Configuration Language (SCL) engineering files. The Standard defines six types of SCL files (ICD, CID, IID, SSD, SCD and SED) to be managed by three engineering tools (System Specification Tool, System Configuration Tool and the vendor-specific IED Configurator Tool). The ability to integrate the revenue meters into these engineering processes firstly requires the adoption of the IEC 61850-7-4 Logical Node data models. In principle this is a relatively simple task for the vendor to redefine their embedded vendor-unique names for the setting fields and information registers according to the Standard's Logical Node semantics.

IEC 61850-7-4 Edition 2 Annex F introduced the key time period mechanisms for the Watt-hour consumption and average demand calculations over:

- Fixed period (e.g. 5, 15, 30 or 60 minute intervals)
- Sliding window
- Period with multiple refresh
- Sliding with multiple refresh
- Total with periodic refresh

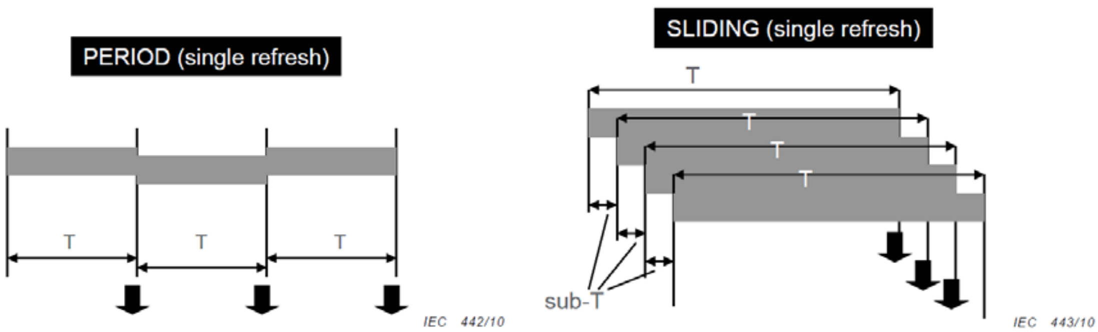

Figure 4 Some of the demand period methods provided in IEC 61850-7-4

However to date there has been almost no widespread take up of IEC 61850 in the revenue metering context. Moreover, currently there seems to be only one European and one Chinese revenue metering device supplier providing class 0.2S IEDs with IEC 61850-9-2 Sampled Value input capability.

Arguably there seems to be at least three main reasons for such limited take up to date of IEC 61850 in the revenue metering domain.

1. The domestic/end use billing meters are generally standalone devices that are not integrated into the facility's protection and other information systems.
2. The utilities have adopted remote meter reading since the 1980's through highly specialised proprietary meter reading protocols and systems. It is notable that revenue meters are generally limited to provision of RS232, 422 or 485 communication ports with very limited adoption of Ethernet RJ45 or fibre ports thereby limiting the capability and benefits of integration into a LAN-based IEC 61850 system and engineering process .
3. The third is somewhat more commercial in that the bulk revenue metering market is multiple orders of magnitude smaller than the domestic market which tends to limit vendor interest in significant new developments.

4. Standards as barriers to IEC 61850 metering

One of the key issues for bulk supply point revenue is compliance to international standards and national regulations.

IEC 60253 deals with a number of different device requirements covering electromechanical meters through to electronic meters in various classes. IEC- 60253-22 (2003) deals with static class 0.2S meters in common use today.

However clause 1 of IEC- 60253-22 specifically limits consideration to "*transformer-operated static watt-hour meters*" and "*measuring element and register(s) enclosed together in a meter case*". This clearly stipulates a single box for measuring the analogue waveforms and performing the calculations. Indeed the test procedures are based on precisely that requirement to inject current and voltage into a single device and compare the Watt-hour readings with a reference meter with the same inputs.

The IEC 62053 22 Standard basically assumes four components to a metering system:

1. CT;
2. VT;
3. a single standalone meter box responsible for turning the Voltage and Current inputs into Watt-hour readings;
4. copper wires and test links (with tamper proof security terminations).

Conventionally we can define and test as individual components

1. the accuracy of the CT,
2. the accuracy of the VT,
3. the accuracy of the (single vendor) meter as an overall device for reference current and voltage inputs.

and then we can verify they will all combine to achieve the required overall accuracy, which is often lower than the sum of the individual required accuracies. For example a 0.2 class metering installation requires the CT to meet 0.2%, the VT to meet 0.2% and the meter to meet 0.2%, but the overall metering accuracy of the metering installation must be 0.5%. So better than 0.2% is required especially when the copper cables losses also need to be taken into account.

Herein lies the first issue that a fully digital substation metering solution segregates out the single meter device into a number of individual devices

As shown below, a single one-and-half circuit breaker scheme may involve

- six different Merging Unit from possibly six different vendors: MU1
- at least one IEEE 1588 Grand Master clock supplier: Clock
- any number and brand(s) of LAN switches with clock support
- the meter IED itself Meter

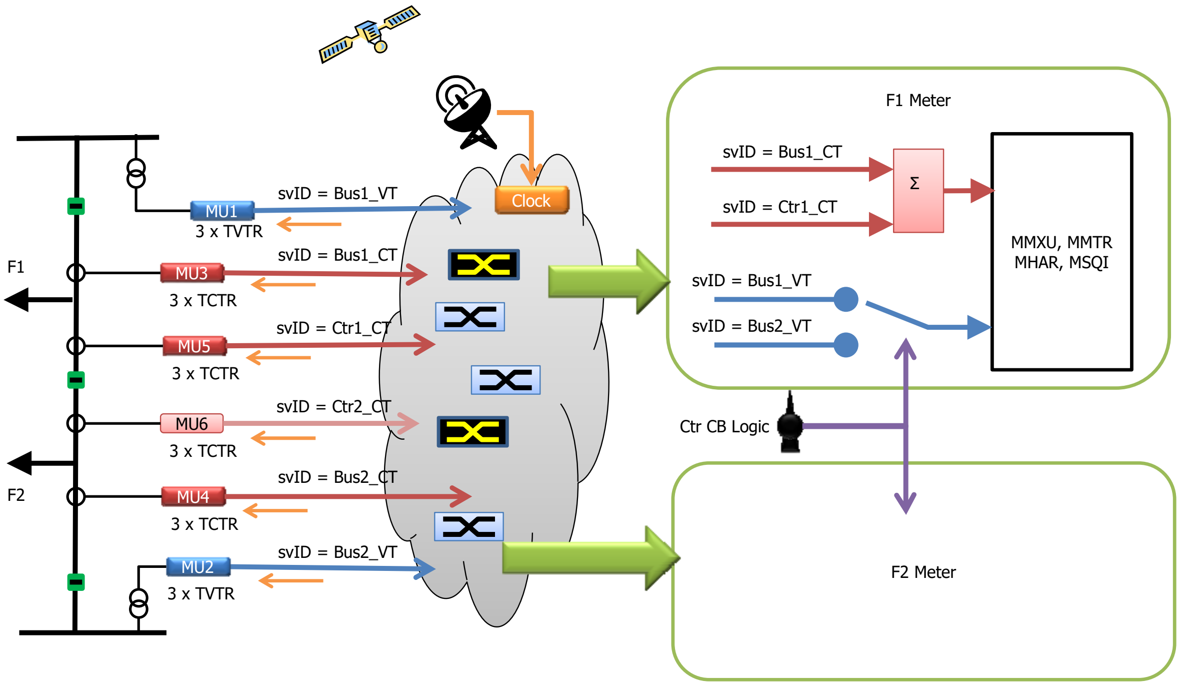

Figure 5 Multiple Sampled Value streams for 1.5 CB diameter

However beyond the Standards themselves, there are often national regulations of some form that dictate the requirements for these bulk revenue meters. In Australia this is provided in the National Electricity Rules chapter 7. It should be noted that the NER specifically states that it the specification does not preclude the application of evolving technologies, however the challenges remain of applying new technologies whist the regulations are not worded to suit.

Subtle statements could exclude new technologies e.g. Australian National Electricity Rules [6]

> *S7.2.6.1 Design requirements*
> *(a) For metering installations greater than 1000 GWh pa per connection point, the current transformer core and secondary wiring associated with the meter(s) shall not be used for any other purpose unless otherwise agreed by AEMO.*
>
> *7.3.1 (b) (3) secure and protected wiring from the current transformer and the voltage transformer to the meter; ……..*
> *(12) a facility to keep the metering installation secure from interference;*
> *(13) test links and fusing;*
> *(14) summation equipment;*

These two clauses imply there are only wire-based connections between the CT /VT and the meter device. Moreover, that those connections are for the exclusive, and secured, use for the metering devices. This is to ensure no tampering of the raw current and voltage signals that would otherwise impact the validity/accuracy of the Wh readings and hence revenue associated with that metering point.

On the other hand, a LAN-based system such as IEC 61850 first of all implies other devices are connected to the same physical LAN. The physical LAN may be deployed as VLANs (Virtual LAN), however , all VLAN's still use the same physical connection and devices, i.e. VLANs simply restricts which messages may be sent into or out of the physical LAN ports depending on LAN switch configurations and message tagging. VLANs therefore provide a degree of device connection port bandwidth control but they are not an effective security measure throughout the LAN.

"Conventional" meter physical security is implemented in the wiring and test block terminations usually through the use of sealed covers to indicate any tampering. A LAN based system clearly has multiple connections points for all manner of other devices, test equipment and computer devices. The LAN by its very nature allows connection and disconnection of these devices and indeed injection of any type of message into the network. A whole raft of issues are created here such as controlling and monitoring the Merging Unit and meter configurations – remembering that the famous STUXNET virus firstly reconfigured the Programmable Logic Controllers at the nuclear plant. In the case of IEC 61850, it becomes necessary to have a secure engineering access control mechanism [19] to prevent unauthorised personnel changing configurations and a detection mechanism for any changes that have occurred. The possible changes of concern include putting the Merging Unit into a mode to send messages tagged as "test" and/or the meter being changed to subscribe to the wrong Sampled Value stream – possibly even spoofed stream (the equivalent of connecting the conventional meter to a different current or voltage source).

Sub-item 14 of the Australian NER clause 7.3.1 is interesting in its own right as the summation process for conventional meters is generally done in the CT wiring or as voltage selection schemes to provide a single three phase set of voltage inputs and a single three phase set of current inputs to the meter. However as shown above, in a LAN based system each of the meter IEDs need to subscribe to multiple Sampled Value streams.

In the one-and-half breaker arrangement above, the meter calculation needs to know which bus VT Merging Unit stream is to be used for the calculation of power flow in each feeder as Feeder F1 may be connected to the bottom busbar rather than the top. This may need the meter to subscribe to several IEC 61850-8-1 GOOSE messages to allow the meter to determine the VT selection.

Furthermore which Sampled Value streams to be summed, or subtracted, has to be managed within the meter. The current Merging Units could produce an instantaneous (not RMS) set of samples at sample point number "n=1349"

MU3 428.321 A
MU4 179.827 A
MU5 -234.652 A

Note as instantaneous samples taken at time point "n = 1349" there is no RMS value or phase information contained in the messages – just magnitude as positive or negative at that instant.
Consequently the value of the sample as communicated in the Sampled Value data set of the message is just the value of the sample and that value may be positive or negative depending on the half cycle of the waveform. In particular whether the value is positive or negative is not related to whether the power flow is to the right or left through the CT!

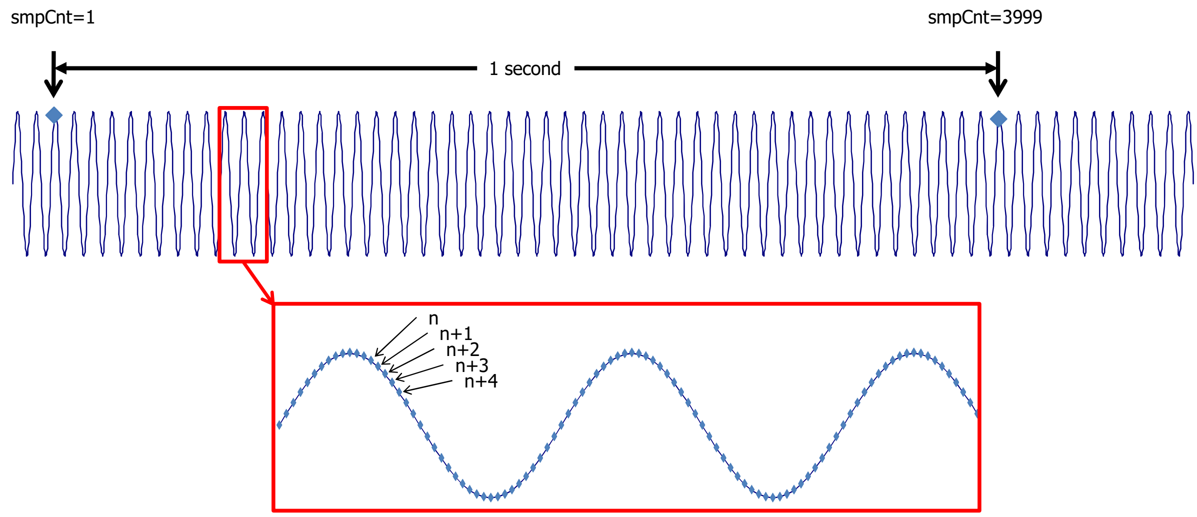

Figure 6 Samples are tagged by the Sequence Number of the sample within the 1-second window

Also to note is that the Sampled Value message does not contain the date and time of the sample, but simply just the count number of the sample within the one-second window. It is for this reason the prime requirement is to provide accurate time synchronisation to better than one microsecond of all the Merging Units so that their one-second windows all start at that same instant. This can only be achieved with the IEEE 1588 (2008) Precision Time Protocol, although there is some special considerations in how that is required to, and can, be deployed. The subscribing meter can then rely on the message and the dataset tagged as sample number "n" from each Merging Unit has been taken at the same instant.

The three instantaneous values from the three Merging Units on their own do not provide the meter function with sufficient information to add or subtract the current values obtained from each of the Merging Units to calculate the total current in each of the feeders. Whilst we would generally say that CTs are "simply summated" in conventional wiring, from the point of view of a device being connected to the LAN and receiving three messages with the three samples as above, the meter has no idea of what the polarity of the source CT and Merging Unit may be. Hence two very different results of value and direction could be obtained as shown below depending on the assumed CT polarity of the centre "I5" CT or the polarity of the connection of the Merging Unit. Indeed there is nothing in the Sampled Value messages themselves to indicate what polarity is represented in I3 or I4 either. Consequently, compared to "conventional" input meters, some commissioning configuration and/or logic has to be provided to instruct the meter on whether to add or subtract the different samples to calculate the true current magnitude and power flow direction in each of the Feeders.

Table 1 Necessity to know CT and MU polarity with respect to add/subtract samples

I3 polarity Instantaneous sample	F1 flow and derived Instantaneous sample	**I5 Polarity** Instantaneous sample	F2 flow and derived Instantaneous sample	I4 polarity Instantaneous sample
→ 428	⊤ ↓ 662	→ **-234**	⊤ ↑ 55	← 179
→ 428	⊤ ↓ 194	← **-234**	⊤ ↓ 413	← 179

5. Meter accuracy certification

As revenue meters associated with bulk supply points, overall metering system accuracy is paramount as even small errors imply significant financial variations. It is then no surprise that the Standards and national regulations referenced above have a significant focus on achieving an overall metering system accuracy. In principle this boils down to providing accurate current and voltage sensing plus, as far as the Standards are presently stating, a suitably proven accurate meter that accepts the CT and VT inputs and produces accurate watt-hour readings.

This single box accuracy test however clearly does not apply when there are several different boxes and several different box suppliers. It is possible to test a specific combination of boxes as a “metering system”, however that combination (and configuration) of suppliers and individual box performance characteristics cannot be assumed to be the same in another substation project, or indeed over the life time of the substation (perhaps 50 years or more)! This certainly presents a challenge (as yet to be addressed) to both Standards and national regulations to provide metering system “component testing” of the Merging Unit, Master Clocks, intermediary clocks (and network design), and the meter IED itself. Appropriate “component testing” will provide a basis of allowing combinations of different certified devices in the true spirit of interoperability.

For the time being, it is necessary to develop a proprietary approach to specific combinations of devices. The experience of this utility has shown some interesting results for the meter and the Merging Units as discussed below.

There are two accuracy test levels in Australia. The first is the “National Electricity Rules”, all metering installations must meet the accuracy requirements. The second is “pattern approval” which applies for meters (and instrument transformers) that measure less than 750MWh per year. The “National Measurement Institute” (NMI) defines the tests for pattern approval. As Australia’s largest HV/EHV transmission utility, TransGrid has no requirement for “pattern approval” meters, however it is considered good industry practice to meet both the NER and the NMI requirements.

TransGrid’s investigations of potential device suppliers identified some six Merging Unit suppliers (conventional analogue 1 A, 110 V input - IEC 61850-9-2 output) and one viable IEC 61850-9-2 input meter supplier. After a tendering and evaluation process, three brands of merging units were tested to be used in combination with the one revenue meter. Tests were carried out using samples at 80 samples per cycle, but it is also noted that the UCA IEC 61850-9-2LE Guideline also provides for 256 samples per cycle for power quality requirements.

6. Meter Accuracy Test Results

Since the meter IED is now effectively “just a calculator” it is feasible to test its calculation accuracy with a known set of sampled value messages. Note that this does not involve any requirement to consider the impact of the LAN topology or configuration as the IEC 61850-9-2 mechanism allows the meter to wait till it has received all the necessary time aligned samples before performing its calculations.

A test set was used to inject IEC 61850-9-2LE frames directly to the meter LAN port and record the watt-hour pulses produced by the revenue meter with the results shown below.

The meter easily met the requirements for metering accuracy on the more stringent NMI tests. The only test the meter failed was the 50% voltage test where the primary voltage sent via sampled values is halved. The meter has an inbuilt voltage cut-off which causes the meter to read zero Watt-hours when the represented voltage is too low. The specific reason for this is unknown to TransGrid, but is suspected to be a hangover from conventional metering design.

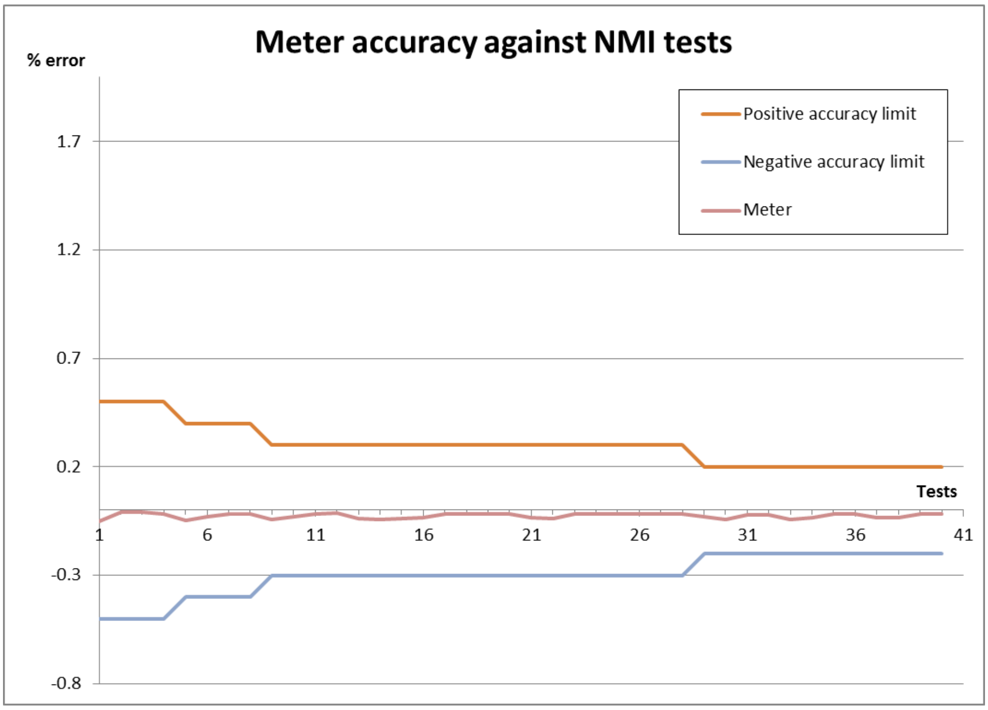

Figure 7 Accuracy of the tested meter IED was well within limits

7. Merging Unit Accuracy Test Results

The three merging units were tested against the less stringent NER requirements. A test set was used to produce the required analogue signals to the merging units. An Ethernet network transported the 61850-9-2LE frames to the meter. Pulses were recorded from the meter and feed back to the test set to determine the accuracy. The tests performed include all four quadrants with currents ranging from 0.1 A to 1 A on a 1 A rated secondary system. Each test is shown on the graph and the tests have been ordered from highset accuracy limit requirement to lowest requirement. In general, the lower the injected current, the higher the allowable error.

Only Merging Unit #2 was specifically designed for a metering requirement i.e. a dynamic range for accuracy up to typically less than two times rated current, in this case up to 10 A (2 x 5 Amp). The other two Merging Units are suited to protection applications with the upper RMS current limit in order are 20 A and 40 A on a 1 A rating.

As shown in Figure 8, Merging Units #1 and #2, in combination with the proven meter, met the requirements of the NER accuracy tests. However Merging Unit #3 failed several tests all associated with low levels of current. It should be noted that Merging Unit #3 had the highest current dynamic range, hence it was unable to accurately measure low level currents.

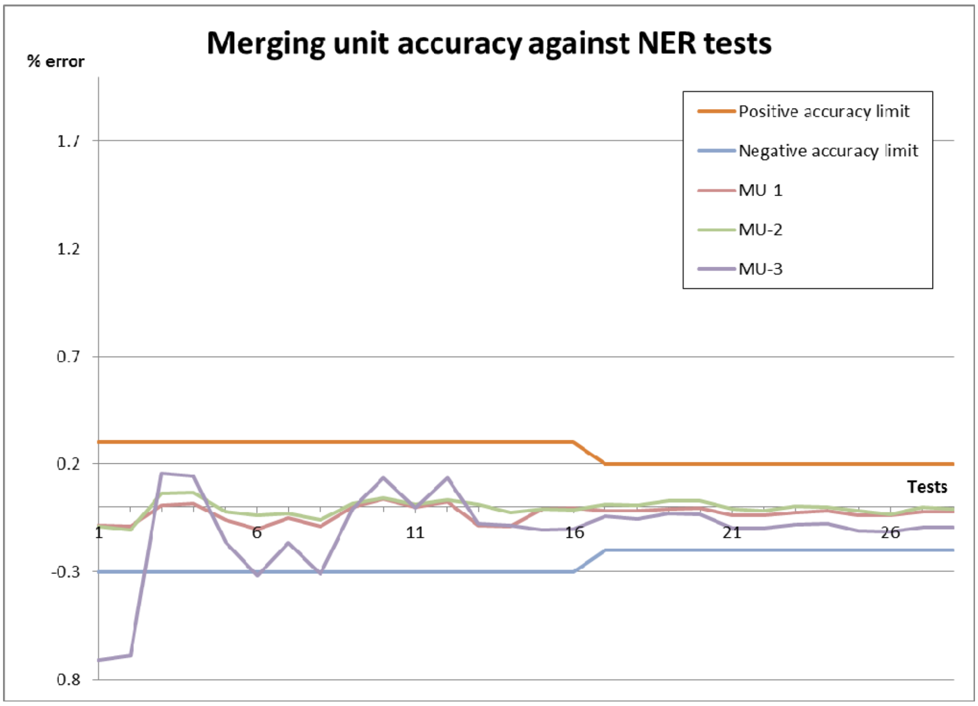

Figure 8 NER Merging unit accuracy tests – MU#3 has errors outside of limits at low currents

The final test results of Figure 9 show the first two merging units results when the more stringent NMI tests are performed. Both merging units failed the 0.01 A accuracy test (NER accuracy test only requires 0.1A) but passed at 0.02 A.

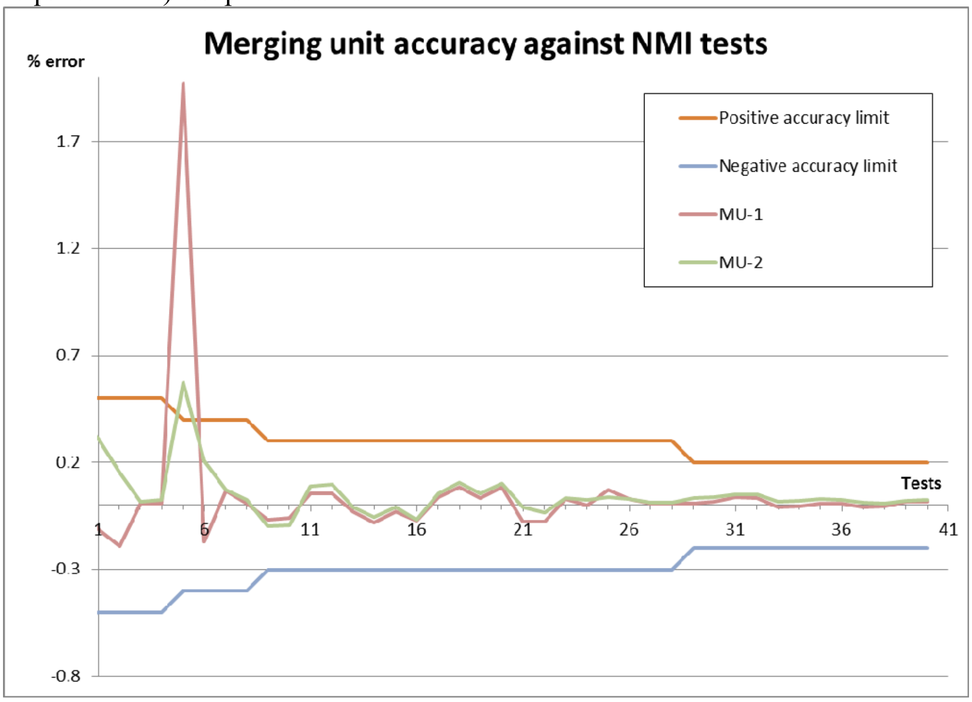

Figure 9 NMI Merging unit accuracy tests – MU#1 and MU#2 have errors outside of limits at low currents

With the exception of the 50% voltage test (caused by the meter), two of the merging units met the accuracy requirements of the NER. None of the merging units met the more stringent NMI tests but did come close to meeting the requirements.

TransGrid considers at least at this stage of available technology solutions that the test results indicate that Merging Units specifically designed for metering applications would be able to meet the NMI accuracy requirements. However it may be a difficult requirement for a protection application

Merging Unit with conventional 1 A analogue inputs to satisfy both the low and high current dynamic range analogue-to-digital conversion.

At this point it is to note that these tests are specifically for conventional CT and VT inputs to the Merging Units. TransGrid is aware of the potential for use of so-called “non-conventional instrument transformers” (NCIT) or “low power instrument transformers” (LPIT) such as optical CTs and Rogowski coils. It is quite feasible that the electronic drive and sensing units associated with those technologies can produce IEC 61850-9-2 Sampled Values directly. By all reports the dynamic range of such sensors is far superior to conventional CT/VT and hence perhaps the limitations experienced above may be obviated. However TransGrid will implement alternative sensor technologies in a later stage of the project but for now, there is a large deployment of conventional sensors where it will still be necessary to derive IEC 61850-9-2 Sampled Values in existing secondary system refurbishments.

8. **Network topology**

Sampled Value message streams are approximately 8 Mb/s bandwidth. At first glance this is not a problem with modern network switches easily being able to provide 100 Mb/s port speeds, even when the meter device needs to subscribe to six streams. Even the addition of infamous IEC 61850-8-1 GOOSE or MMS messages is highly unlikely to overload the ability of the IED to publish or subscribe to the information it needs.

However, even medium sized substations could easily end up with 30 – 50 Merging Units and hence a total backbone bandwidth of 400 Mb/s just for Sampled Values. Since Sampled Values are a multicast message (i.e. no specific destination address) every IED on the network (meters, other Merging units, protection, RTUs, Bay Controllers, condition monitoring, gateways, HMIs …) will receive all those messages on their LAN ports, i.e. 100 Mb/s ports would be insufficient unless suitable multicast filtering and/or VLANs are provided in the LAN switch configuration (which introduce other engineering requirements). Large port-count switches with 1 Gb/s bandwidth ports are now reasonably common, never the less, a 1 Gb/s switch-to-switch backbone should be considered as the absolute minimum, and perhaps even 10 Gb/s.

The LAN topology itself does not affect metering accuracy however it may have some bearing on how it performs under a Failure Mode Effects Analysis (FMEA).
Clearly a LAN based metering system relies on the sending of the Sampled Value messages from the Merging Units and the successful reception by the relevant meters. There may be some consideration of duplication of the metering system just as the protection system is often duplicated for redundancy objectives. (Required for Type 1 metering, partial for Type 2)

Whilst LAN architectures such as Rapid Spanning Tree Protocol (RSTP) provide an automatic recovery for a ring connected LAN, this may take a noticeable period of time which will cause disruption to the protection system, and in any case there is still the single point of failure of the communication port connection from the IED to the network switch (and of course the failure of the meter IED itself). Whilst this may be a very short term “glitch” in the metering period, there are revenue implications and never the less the metering system will use the same LAN network as the protection. Protection systems have already considered this issue and may employ a higher level of resiliency in the LAN itself by consideration of the so-called “bumpless” network topologies of the IEC 62439-3 options for Parallel Redundancy Protocol (PRP) or High-availability Seamless Redundancy (HSR - not to be confused with an earlier proprietary protocol of similar name).

Without giving details herein of how PRP or HSR operate, the fundamental requirement is the IEDs (Merging Units and meters) have at least two communication ports supporting the protocol.

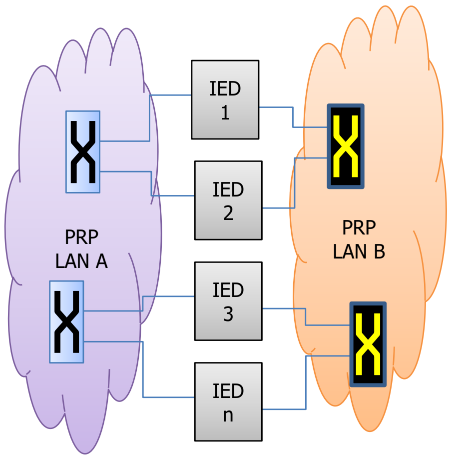

Figure 10 PRP requires two independent LANs including switches – IEDs must have two ports

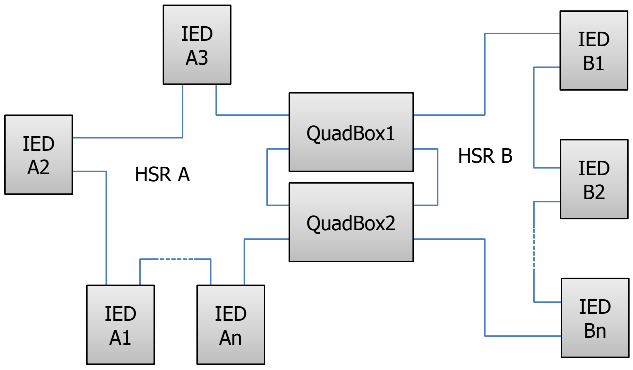

Figure 11 HSR may need multiple HSR rings to limit number of IEDs per ring, – IEDs must have two ports, but no switches

9. Remote Meter Reading Systems

One of the consequential issues for bulk revenue metering being provided by a LAN-based IEC 61850 system is the ultimate objective of metering – reading the meter so that billing can be done!

In some countries the role and responsibility of reading the meter is by regulation required to be outsourced to independent and approved contractors. With conventional metering solutions, the meter itself simply needed to support a typically RS232 or RS485 communication port for connection to a secure dial up modem. Software systems such as Itron's MV-90 provide mechanisms for the meter reading contractor to schedule automatic dialling of each meter to extract the relevant data. These systems simply have a telephone number assigned to each meter.

Whilst it may be possible to have both a LAN port and serial RS232 port on a meter, this is clearly not a cost-optimised solution – especially as this then adds dual protocol handling requirements and perhaps even data segregation within the meter structure.

One of the main reasons meter reading via the LAN is important is; it turns the meter into the same as every other IED, i.e. it only needs auxiliary power supply, case earth and a LAN connection(s). This allows the meter to be included in the utility automation system engineering processes defined by IEC 61850-6 using the prescribed engineering tools and SCL files. The meter then can be located on the same panels as any other IED.

However, a meter only supporting Ethernet LAN port connectivity then requires the utility to provide secure mechanisms for these third party meter readers to connect to the substation LAN. Clearly there must be some appropriate security around that connection and many controls around what the third party meter reader is able to "see" and "do" on the LAN, i.e. they must be restricted to only seeing the relevant meters they are required to have read-only to (perhaps a subset of all meters on site).

Certainly the meter reader must not be able to modify configuration of any of the Merging Units, meters clocks, switches nor any other IEDs on the LAN. On the other hand it is not unreasonable for the utility to also be able to read the meter themselves without risk of interfering with the raw data. Whilst the utility could undertake the official role of the meter reader (if they win the meter reading contract bid), this does place certain regulatory obligations and liabilities which they may not be prepared to accept.

This is not to forget that the meter reading software would therefore need options to identify a target meter by either a telephone number or an IP address in a substation LAN of a particular utility. This presents other issues for permission to connect as these appointed meter readers may change under new contracts and the readers may be responsible for a subset of meters at each location, multiple substations within each utility and indeed multiple utilities.

This also raises a question about data security inside the LAN-connected IEC 61850 based meter. Standards and national regulations require the derived meter data of recorded energy usage is stored securely for perhaps 200 days or more and must not be able to be tampered with. This brings into play consideration of multi-level passwords to be assigned (and managed) incorporating the third party meter readers. Whilst IEEE 1686 defines multi-level password system for IEDs a s good starting point, IEC 61850 itself does not have any password data model, change commands or login command-response mechanism. This forces such issues into the realm of proprietary configuration and tools. There is some work currently under consideration by IEC TC57 Working Group 17 on establishing security measures for machine-to-machine certificate handling within the substation, however effective handling of third party meter reading systems will need to be incorporated.

10. **Conclusion - the need and the opportunity**

The business case for implementing IEC 61850 is built on the combination of

- Engineering process (time and cost)
- Elimination of human error in the engineering and commissioning process
- Reduction of wiring and associated commissioning
- Reduction of civil works for the infrastructure of copper based cables
- Significantly improved substation failure/disaster recovery mechanisms

The recent increase in vendors offering Merging Units with IEC 61850-9-2 outputs has opened the market to the possibility of a fully digital substation and all the benefits this will yield.

However these benefits are severely limited if part of the substation secondary systems – notably the revenue metering systems – remain constrained by the traditional/conventional wire based yard wiring requirements.

At this stage it is somewhat unacceptable in a commercial sense that there has only been a single effective supplier of IEC 61850-9-2 input meters. Whilst performing admirably for its accuracy as a “calculator”, that meter still needs some feature enhancements to be fully usable in transmission substation applications as described herein (multiple Sampled Value message subscription and some selection/summation logic).

The somewhat disappointing and surprising aspect though is the difficulty to obtain a Merging Unit that will satisfy producing the IEC 61850-9-2 Sampled Value messages which meet the stringent low current magnitude requirements for accuracy defined by Standards and national regulations. This is despite the UCA2 IEC 61850-9-2LE Guideline for CT/VT applications describing such low level accuracy requirements.

Other applications such as power quality (256 samples per cycle) and Travelling Wave Fault Locators would presumably also need to be considered in respects of suitable interoperability of the “calculator” function IED with the Merging Units.

However as a system with significant revenue impact, further work is necessary by suppliers in the provision of both Merging Units and meter IEDs for bulk revenue metering, albeit that under some restricted application scenarios / Standards, the concept has been proven to be viable and beneficial.

AUTHOR BIOGRAPHY

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Rod Hughes: Graduating from Sydney University in 1980, Rod Hughes has over 35 years’ experience in the power industry across Australia and internationally specifically involved in protective relay, instrumentation and metering solutions. He is one of the longest serving members of the CIGRE Australia B5 Panel (26 years) and was the previous Convener of the Australian Panel with two Merit Awards. Keen to assist the industry at large, he is a prolific contributor to protection and IEC 61850 forums on Linkedin. He has served in senior management roles with a vendor (including France for three years), utility (ElectraNet) and consulting firms, eventually in 2009 establishing his own private consulting firm focused on protection system specification, change management advisory along with IEC 61850 deployment and vendor-agnostic training services. Rod is also responsible for a patent application for IEC 61850 operator and test interface unit. Rod has provided protection application training to hundreds of protection specialists across Australia and New Zealand and in more recent times as one of the few industry recognised vendor-independent Australian trainers for IEC 61850, he has also trained hundreds in the principles and processes of IEC 61850 deployment.

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