IEC 61850 Enabled Automatic Bus Transfer Scheme for Primary Distribution Substations

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***Abstract*—Automatic bus transfer scheme (ABTS) is the practice of transferring a load bus to an alternate source when the normal power supply fails or is tripped thus ensuring continuity of supply. This paper comprehensively reviews existing schemes and implementations of ABTS especially for motor bus. To limit the fault levels, during certain situations, the transformers supplying a primary distribution substation can be run in split instead of parallel operation. This is because during outages if one transformer is lost, overloading of remaining transformers, if it occurs, can be managed. This paper proposes an ABTS for a primary distribution substation for a utility facing such a situation and present details of its implementation. In the proposed scheme which is enabled by digital communications, if a transformer is lost, the bus section circuit breaker (CB) will be closed automatically after the incomer CB trips. The proposed ABTS has been implemented in the bus section relay for a new 11 kV switchboard where inter-relay communication is based on the IEC 61850 suites of standard. The contribution of this paper is that it shows how to use a standard automation scheme smartly to defer network reinforcements and manage fault levels in primary distribution substation.**

***Index Terms*—Automatic bus transfer scheme, IEC 61850, intelligent electronics devices (IEDs), substation automation.**

I. INTRODUCTION

IN MODERN distribution network operations, increases in substation loadings requires to be managed smartly. To meet emerging loads it is likely that some substation might require housing additional transformers but due to increased fault levels they cannot always operate in parallel with the other existing transformers. Implementing smarter and cost-effective bus transfer schemes to manage the operation of parallel transformers is one option.

New planned subdivision and relocation of large industrial customers to the suburb necessitates increased local distribution network capacity. The traditional approach to addressing this is often to construct a new primary substation. While this will certainly address the immediate need and provide excellent network security, it usually comes at a considerable cost. The financial incentives to defer this investment is significant, therefore to meet these emerging loads the modern distribution network operator will often seek to increase the capacity of existing substations by installing additional transformers. However it is likely that for existing local primary substation this can result in raising the fault levels beyond design limits when operated in parallel with the existing transformers.

A high impedance primary transformer can be used to limit fault levels. However these assets are non-standard equipment, meaning that spares would not be readily available in the event of its failure. Additionally sub-optimal load sharing will occur between the transformers during normal operation. This effectively reduces the useful rating of the new transformer when operated in parallel with the other existing units.

Other primary equipments such as series reactors and neutral earthing resistors can be used to restrict fault levels but these would incur additional cost and have similar disadvantages like the high impedance transformer solution with regards to maintaining of spares. Series reactors can also potentially result into other issues such as the production of electromagnetic radiation that are difficult to be kept within the regulatory limits.

One novel approach proposed in this paper is to restrict the network configuration so that the substation busbar is run spilt under normal operation. The obvious disadvantage of this technique however is that if a transformer trips then feeder outages or overloading of the remaining transformer may occur. Clearly if there is a method of quickly and automatically closing the normally open bus section circuit breaker following such an event is available then these shortcomings can be minimized. The developments and investments in smart grid by distribution utilities provide opportunities in this direction.

The concept and development of the term and definition of smart grid is arriving towards a consensus both amongst policy makers and grid owners [1], [2]. The difficulty of interoperability amongst legacy power network controls and emerging intelligent electronic devices (IEDs) is also a significant challenge that needs to be addressed [2], [3]. Towards the end of 2009, National Institute of Standards & Technology (NIST) published an initial suite of smart grid standards. One of the standard included in it, that addresses substation automation and the communication aspect is IEC 61850 [1]. IEC 61850 is a universal communication standard for Substation Automation System (SAS) which has the ability to offer interoperability amongst IEDs from different vendors [2], [3]. In the context of IEC 61850, the functions that are required to be performed by the IEDs are decomposed into subparts which are known as logical nodes (LNs), and each LN usually has a list of data with their attributes [3]. The data and their attributes

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together represent the information which is needed to be exchange amongst LNs by the communication service offered [4] through IEC 61850. This communication service interface is called Abstract Communication Service Interface (ACSI). One of the communication service model in the ACSI models is the Generic Substation Event (GSE) model service [4]. The GSE contains the Generic Object Oriented Substation Event (GOOSE) message [5]. The GOOSE message is being used by protective relay IEDs to send tripping signals [6]. Modelling of distribution system components in IEC 61850 is also being actively researched [7].

This paper proposes a scheme for ABTS and discusses implementation following transformer addition to a primary distribution substation. The overall scheme is realized through IEC 61850 enabled features. With the advent of modern IEDs in substations and the new IEC 61850 substation automation standard such a scheme is deemed to be feasible and can be successfully developed and deployed widely resulting in significant capital efficiency gains.

This paper begins by firstly reviewing existing philosophies of ABTS and its current practice following microprocessor advancement and the availability of IEDs as protective relays. Second, the case study for substation capacity upgrade through ABTS and a new transformer addition to primary distribution substation will be outlined. Third, the IEC 61850 solution to ABTS will be detailed. Fourth, implementation details of the developed scheme on an actual 11 kV distribution substation will be presented which will be followed by testing of the scheme. Finally, conclusions will be drawn and future projections outlined.

II. Review of Automatic Bus Transfer Scheme

Most of the existing publications regarding ABTS are for motor bus load applications [8]–[15]. The existing ABTS for primary auxiliary buses that supply major rotating machinery loads can be classified to include fast, slow, parallel, residual voltage, and in-phase transfer methods [12], [13]. These methods are designed depending upon the criticality of the motor loads, safety of the applied motors, and the cost of implementation [14].

Typically, ABTS operates immediately following an abnormal system condition, such as, a fault or equipment failure. Some examples of these includes loss of one utility source, upstream transformer cable/line fault, substation transformer failure, bus fault, downstream cable/line fault, etc. There can be special considerations which will dictate some in-depth and case specific assessment [9], [11]. Historically, ABTS using discrete relays provide both automatic and manual operating modes. ABTS restores power to either "A" side or "B" side of substation main buses. Manual make-before-break operation is used to retransfer to the normal open tie configuration or manually transfer the substation (closed main, closed tie, and open main) for maintenance, repair, or modification [8], [10].

Fig. 1. illustrates a typical secondary selective system with ABTS controlling the operation of the circuit breakers (CB). The purpose of this ABTS is to reestablish power to one of two main buses following transient disturbance situations and

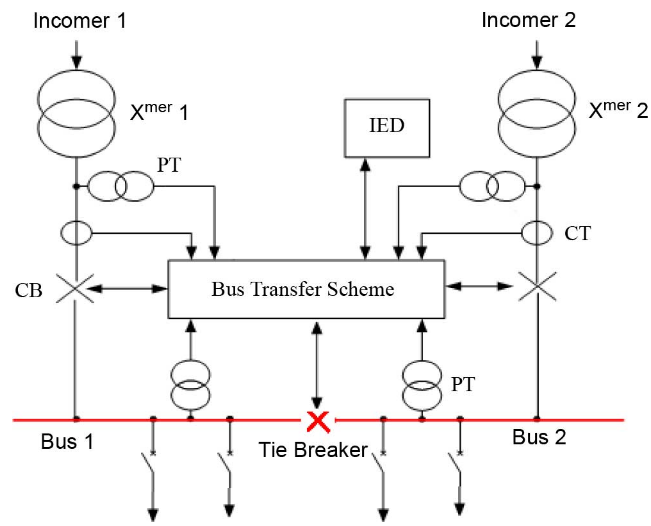

Fig. 1. Building blocks of the automatic bus transfer schemes.

to block transfer during through fault conditions. Transfer is allowed during stable system conditions with normal system voltage available to maintain or reaccelerate operating loads. The inputs to this scheme includes current transformer (CT), potential or voltage transformer (PT/VT), relays and other monitoring and interlocking devices of substation automation. In the context of emerging substation automation vocabulary IED is the keyword that captures these secondary system control and protection elements.

An example of ABTS is the loss of incoming source 1 side voltage, whereby its CB breaker is tripped. After bus 1 residual voltage decays to an acceptable level and bus 2 voltage is normal and stable, tie-breaker closes, and 2 side power is supplied to bus 2. After a transfer operation, return-to-normal open tie breaker operation is performed manually. The sync-check relay permissive inhibits CBs in incoming lines and tie breaker CB from being simultaneously closed, unless the two incoming sources are in synchronism. The sync-check relay and hence its permissive is not required when both incoming sources originate from the same upstream synchronized substation. The tie breaker trips following successful synchronization of both sources and normal pattern of supply is restored. Momentary closure of the three CBs may significantly increase the downstream fault duty. Because of this concern, some manual transfer operations are not make-before-break. These control options are well established and determines the logic of the bus transfer scheme implemented.

A summary of all the four typical transfer schemes are available from [14]. Table I represents a quick comparative view of these schemes discussed there. Bus voltage column corresponds to if monitoring of the voltage is required for the scheme. Slow transfer scheme typically does not require the bus voltage to be monitored. All others require bus voltage monitoring. The cost column corresponds to if the scheme is relatively cheaper. Slow and residual transfer schemes are relatively less expensive compared to the other two schemes. The need for a synchro-check relay to verify that the bus is in synch with the source when returning back to the normal source is shown in the column corresponding to synchronizer (represented by an yes "Y" if needed).

TABLE I
COMPARATIVE ASSESSMENT OF BUS TRANSFER SCHEMES

Transfer	Bus voltage	Cost	Synchronizer	Complexity	Time (sec)
Slow	N	Y	N	N	X
Residual	Y	Y	N	N	> 0.5 and < 3
Fast	Y	N	Y	Y	< 0.2
In-phase	Y	N	Y	Y	> 0.2 and < 2

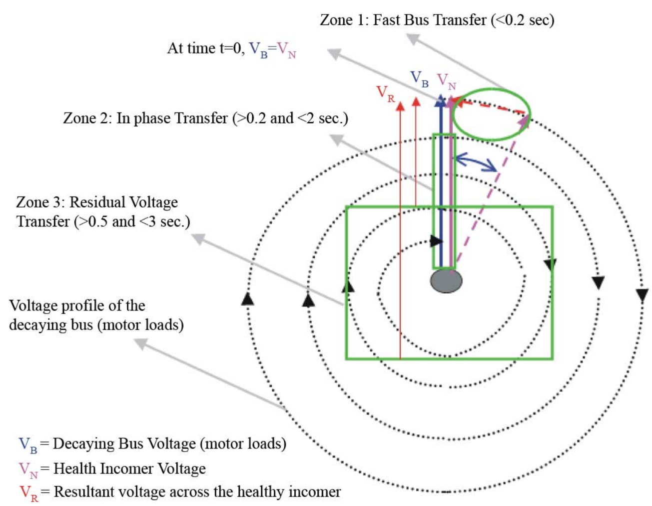

Fig. 2. Bus transfer zones [14].

The complexity of the scheme is generally dictated by the supervisory, inter-locking and timing requirements of the scheme (indicated by "Y" in the complexity column of the table) and corresponds to increasing cost. The cost increases to realize increased complexity is due to the need for accurate information like, e.g., tie breaker closing time, etc., for the scheme to be implemented.

The time column generally corresponds to the timing evaluation for the motor bus requirements. Slow transfer schemes are usually designed to wait for a predetermined time (hence shown as X in Table I), which is normally greater than 0.5 seconds before connecting the decaying bus voltage to the alternative healthy incomer source. This is captured in Fig. 2 available from [14].

The overall control scheme for the bus transfer scheme will need to operate automatically during abnormal operational situations and facilitate quick manual transfers. During plant expansions and modification, the system can be re-configured by performing a manual transfer. Only tie breaker failure or a bus fault with single-ended operation requires a total shutdown of the substation.

The transformer protection and control can also be integrated into the ABTS, if the substation design requires one. This can then include features like tap-change voltage control and even capacitor bank switching. On similar lines, adding a high-impedance bus differential relay scheme greatly reduces bus fault clearing time for main bus faults and serves to minimize arc flash zones. However, this will then require coordination with a down-stream transformer differential protection, if any, using a transfer tripping scheme. In certain situations system tripping includes a transfer trip from the downstream substation switchgear incoming breaker to the upstream feeder breaker trip circuit. This is particularly useful to increase sensitivity with low-resistance grounding and restricted earth-fault relays at the downstream substation, because the upstream feeder phase protection cannot sense the low magnitude ground fault on the secondary side of the downstream transformer. The transfer trip implementation historically uses pilot wire relaying or remote input/output (I/O) connected via fiber-optic cable.

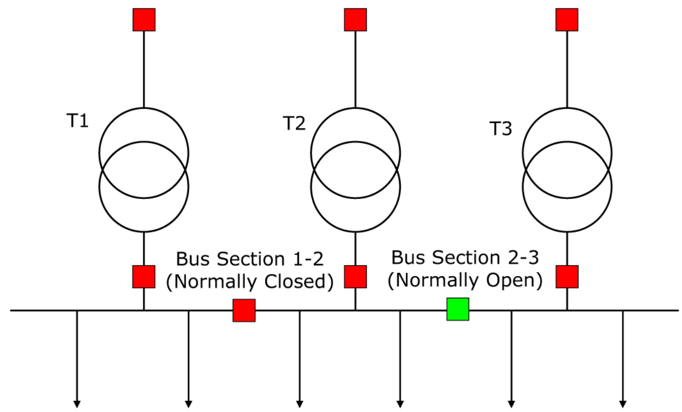

Fig. 3. Normal configuration for distribution substation following installation of a third transformer.

Within the scope of this paper we do not include the above discussed features but the methods and procedure proposed here for developing an ABTS can be easily integrated in future with other integrated automation, control and protection schemes in future.

III. DISTRIBUTION SUBSTATION CAPACITY UPGRADE

Fig. 3 presents the planned configuration of distribution zone substation after its third transformer is installed. Taking into consideration the fault level management, bus section 2–3 is to be run normally open and bus section 1–2 is to be run normally closed. ABTS is the most economic means to adding substation capacity without increasing fault levels but it does not result in any increased revenue for the utility. Other possibilities to be compared include series reactor, neutral earthing resistor and high impedance transformer. The option we propose in this paper is the control and automation of a split-bus scheme. Two cases are considered in the ABTS which requires decision to be made by bus section 2–3's IED. These cases are elaborated in the following subsections.

A. Case 1: T3 Trips

In this situation feeders connected to T3 bus bar will lose supply. Bus section relay 2–3 will check parameters and if it is safe to do so will automatically close its circuit breaker. Once T3 has been restored the control room operator should ideally open either bus section before the T3 incomer CB is closed, to prevent paralleling of all three transformers.

B. Case 2: T1 Or T2 Trips

Overloading of remaining transformers could occur, and loss of any additional transformer will cause loss of supply to feeders attached to that transformer's bus bar. Bus section relay 2–3 will check parameters and if it is safe to do so will automatically close its circuit breaker.

Once both T1 and T2 are operational again the control room operator should ideally open either bus section before the incomer CB is closed. This is to prevent paralleling of all three transformers.

C. Special Considerations

For both situations listed in the previous subsections the following considerations are required to be satisfied to ensure that the overall scheme operates safely and reliably:

1) Safety: The scheme must only operate for the two cases described in the previous subsection. A dangerous situation can occur if the bus-section were to automatically close on to a fault following a bus-bar or downstream uncleared feeder fault. This has the potential to cause a cascading outage that could affect the whole primary substation.

If all three transformers are paralleled then there is also a safety hazard due to fault levels rising above design limits. The scheme needs to be designed so that this risk is avoided.

2) Self Monitoring: The scheme should have the ability to monitor its own integrity, especially with regards to the automation scheme, to ensure its availability at all times and also to minimize re-testing requirement after commissioning.

3) Control: Control to turn the automation scheme on and off should be provided both locally for technicians and remotely for control room operators.

4) Speed: The scheme should operate as fast as possible to minimize disruption and potential overloading of remaining transformers. Special consideration however should be made if downstream distributed generation exists so that the bus section circuit breaker does not automatically close onto an island that has formed following an outage of the third transformer (like in Case 1 in Section III-A).

IV. IEC 61850 for Automatic Bus Transfer Scheme

The IEDs involved in the ABTS need to exchange information to determine when a transformer unit trip has occurred and to determine the position of all relevant circuit breakers so that the risk of paralleling is minimised. As such it is preferred that peer-to-peer relay communications is used to avoid the need for hard wiring.

IEC 61850 GOOSE messaging provides this peer-to-peer communications capability. There are several advantages in using this technology for the ABTS which are:

A. Installation Cost Savings

If GOOSE messaging is available on existing station bus, no additional hard wiring is required for the transfer of information between relays. For substations with existing IEC 61850 compliant IEDs the scheme can be implemented rapidly without the need to replace or rewire any existing devices and equipments.

B. Continuous Health (Integrity) Monitoring

GOOSE messages have been designed to give reliability at least as good as point-to-point wiring so that fast protection

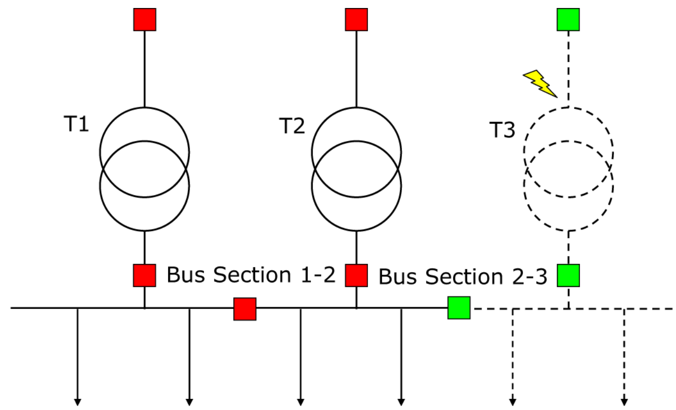

Fig. 4. Case 1, T3 Trip.

messages can be sent over a substation's LAN. Normal Ethernet communication uses acknowledgement messages which ensure that all messages sent reach their destination, but this is done at the expense of transmission speed. GOOSE messages do not use acknowledgements; instead the message is resent multiple times at increasing intervals once an event occurs to ensure that there is a very high probability of the message getting through to its destination. One of the features of GOOSE is the facility to interrogate the status of each transferred message. While the interruption of a connection cannot be detected with conventional wiring, the signal transmission with IEC 61850 has an integrated continuous monitoring which indicates failure of the connection or the transmitter. Since modern IEDs also have inbuilt device health monitoring this effectively makes the entire control scheme maintenance free.

C. Improved Testing

Tools exist which enable the simulation of GOOSE messages. This greatly assists in testing of the scheme compared to the hard-wired approach.

D. Interoperability

Unlike some other peer-to-peer relay communication technologies IEC 61850 GOOSE is vendor independent. Different relay types can be integrated into the scheme.

Fig. 6 proposes an ABTS system that can be developed for the system of Fig. 3 using GOOSE enabled communication features of the IEDs associated with the secondary systems in the primary distribution substation. Such a scheme has been implemented for an actual distribution substation of Fig. 7. The details of the implementation with the design features are elaborated in the next section.

V. Practical Implementation

This section details the implementation of the scheme proposed in Section III for the primary distribution substation network of Fig. 7. As can be seen from the figure there are 2 existing transformers T1 and T2 supplying existing loads through bus 1 and bus 2. Bus section 1–2 is between them. A third new transformer T3 is to be installed in parallel at the same distribution substation, so that savings can be made by avoiding building a

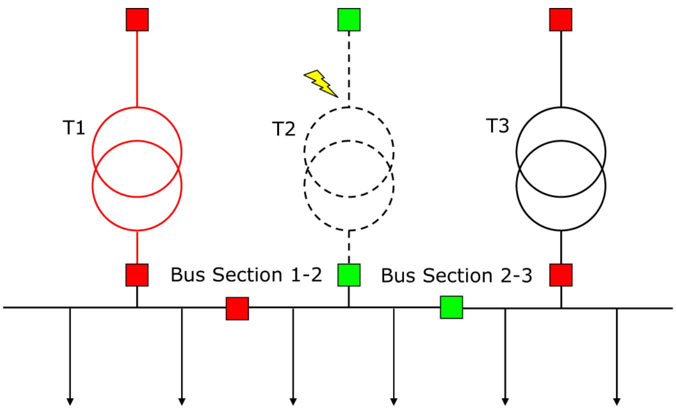

Fig. 5. Case 2, T1 or T2 Trips.

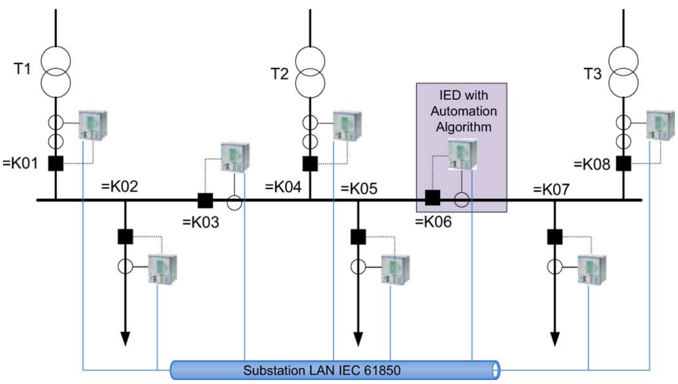

Fig. 6. Design of ABTS using IEDs and GOOSE messaging.

new one, and the bus section 3–1 in this situation can be managed, especially from increased fault levels, using the ABTS design proposed and discussed in the previous section. IEC 61850 compliant IEDs are used at each bus section and its incomer. The relay for 3–1 bus section receives information from the other IEDs via GOOSE messaging to determine if and when the circuit breaker should be closed and is the location where ABTS can be deployed. The following subsections detail how the scheme has been implemented within the IEDs:

A. Detecting Transformer Outages and Preventing Automatic Closure on to Faults

To determine that an outage has occurred, all transformer bay protection trip and circuit breaker status information is sent from the three incomer relays to bus section 3–1 relay via GOOSE messaging. The trip messages only relate to transformer unit protection, transformer Buchholz, pressure relief protections or transformer temperature trips. They are not issued for overcurrent or earth fault (OC/EF), breaker failure or arc detection trip to prevent auto closure onto faults.

For bus section 3–1 to recognize that an incomer circuit breaker has opened due to a transformer bay trip it must receive indication that both the bay trip has occurred and that the incomer circuit breaker has opened within five seconds.

Additionally an extra safety precaution has been implemented to ensure that if the bus section circuit breaker does auto switch on to a fault, it will trip instantaneously by a high-set protection element and lock-out. ABTS will not operate if the bus section 3–1 circuit breaker is locked out for any reason.

B. Voltage and Synchronism Check Before Closing

If a VT failure is detected the automatic change over scheme is disarmed and an alarm will trigger. Before the bus section closes a check is carried out by the relay to ensure that the voltage, frequency and phase angles either side of the section is within a preset range.

This functionality is implemented using a Synchrocheck function. If Synchrocheck is disabled then the ABTS is also disabled.

Before a release is granted, the following conditions must be satisfied:

- T3's bus voltage is dead (< 500 V) and T1's bus voltage is healthy (greater than 9 kV and less than 12.1 kV)
- Or—The voltage of both buses is healthy (greater than 9 kV and less than 12.1 kV)
- And—The voltage difference between the two buses less than 200 V primary
- And—The frequency difference between the two buses less than 0.1 Hz
- And—The angle difference between the two buses less than 10 deg

C. Fault Level Protection

Due to increased fault levels on the 11 kV network there is a risk to plant and personnel if all three transformers at the substation are run in parallel. To minimize this risk without compromising the distribution network operators' ability to effectively manage the network an interlocking scheme to prevent a parallel has not been implemented. Instead, in the event of a parallel an alarm will be raised and a high-set overcurrent protection element is activated in bus section 3–1. The setting for this element has been set to operate at a very low pick-up as under normal conditions there is very little current flowing through the bus section and because discrimination between bus bar and feeder faults is not required (this would be a double contingency).

The bus section 3–1 relay detects a parallel by subscribing to GOOSE messages of circuit breaker position from every bus section and incomer relay. These messages are monitored and in the event of a GOOSE message failure the relay will assume that the breaker status is closed—this means that it is possible for the high-set element to be activated in the event of a communications failure.

D. VT Health Monitoring

The bus section relay monitors the bus voltage transformer through its analogue inputs and if a failure is detected the ABTS will disarm and an alarm will trigger.

E. ABTS Enable/Disabled Controls

The ABTS can be enabled or disabled via bus section 3–1 relay's front panel or remotely through SCADA. The control display, showing how the scheme status is displayed on bus section relay 3–1 is shown below in Fig. 8.

It is important to note that "Enabled" does not imply that the scheme is ready to operate. All operating parameters must be satisfied for the scheme to be "Armed" and active.

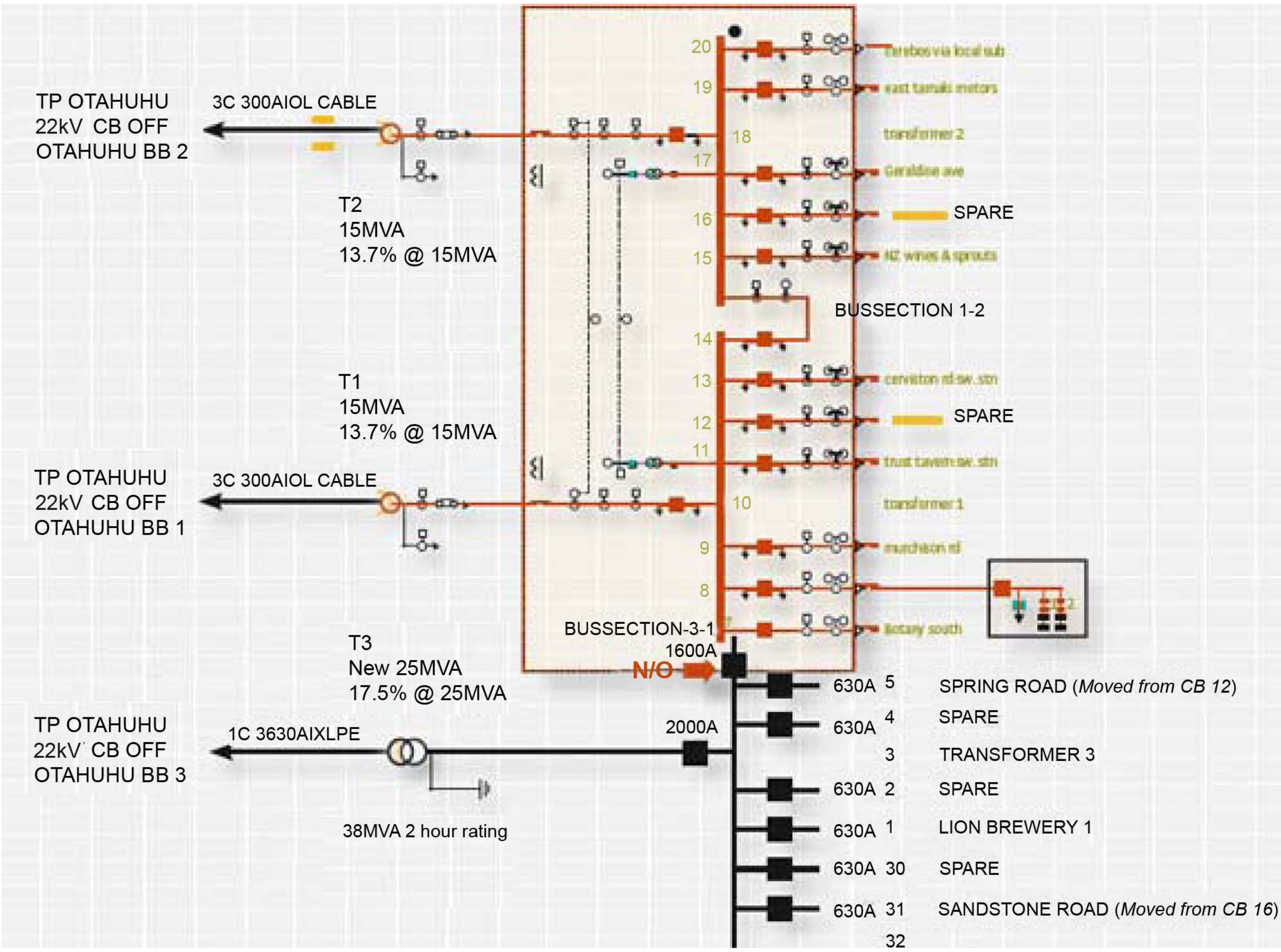

Fig. 7. Primary distribution substation bus.

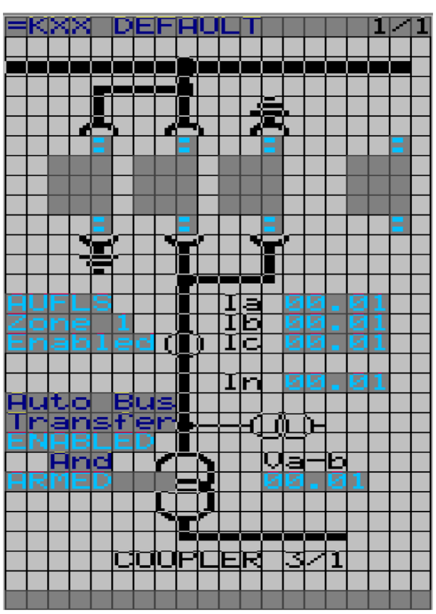

Fig. 8. Graphical display for bus section relay 3–1.

F. Goose Message Monitoring

As discussed previously one of the advantage of GOOSE is the facility to interrogate the status of each transferred message. The ABTS continuously monitors all messages within the substation and will disarm automatic closure if a failure is detected and trigger an alarm to the control room. Time delay before automatic closure

Due to the inherent very fast properties of GOOSE messages the ABTS can potentially operate within milliseconds from the opening of an incomer circuit breaker. However special consideration for distributed generation has to been made in the event of a T3 trip (Case 1 Section III-A, Fig. 4) if there is significant generation connected downstream to bus 3, then an island may form and the bus voltage will not immediately drop off to zero. This will prevent the automatic closing of bus section 3–1 by the relay synchro-check function unless a time delay is applied.

For the actual substation implementation of Fig. 7 such a delay had to be implemented as there is downstream generator at a local land-fill gas power station. The IEEE technical standard for the connection of distributed generation [16] requires that this generator ceases to energize the network within two seconds of the formation of an island. The time delay for the ABTS is thus set to 2.5 seconds before automatic closure to allow these generators to disconnect from the network and for the bus voltage to fall to below 500 V.

VI. Practical Testing Procedure for ABTS

This implementation of bus transfer scheme for primary distribution substation has been made possible by the integration of IEDs into the substation automation projects. It is usually recommended that whenever a new IEC 61850 based control scheme is designed it be bench tested exhaustively. Constructing a suitable test rig, developing a testing methodology [6] and comprehensively test the scheme to uncover any potential issues are important aspect that needs practical considerations before actual implementation. For the IEC 61850 enabled ABTS implemented using the practical case study, thirty-two different tests were required to pass before acceptance was completed. This approach is applicable for factory acceptance test (FAT) of control scheme but is particularly important when using GOOSE to ensure that interoperability between IEDs is achieved and that GOOSE transmission speeds are acceptable.

Pre-installation testing uncovered a number of issues. However these were relatively easy to diagnose and correct on the test-rig when compared to what would have been required during on-site commissioning. The final test requirements after the installation of T3 transformer of Fig. 7 were minimal as a result. The scheme has been tested and is fully operational.

The economic advantage of using an ABTS is the avoided cost of having to build a separate primary distribution substation to house the new transformer bay. For cities where land cost is a premium this can translate into millions of dollars.

VII. Future Extensions Enabled Through IEC 61850 Inter-Substation Communication

IEC 61850 is currently undergoing revision around inter-substation communication and associated architectures. Edition 2 and part 5 of the standards lays out requirements for communication between substation automation systems to utility automation systems. Maturity and acceptance of these practices will offer opportunities for extending ABTS schemes to be integrated with other control and protection schemes requiring interaction amongst more than one primary distribution substations. The next immediate opportunity for ABTS, described in this paper, is towards extending it for inter-substation schemes. This will involve developing distributed logic across one or more primary distribution substations. Considering the scheme discussed in Section IV, for a fault in one transformer the bus-section would close and inter-substation communication can then instruct other neighboring substation transformers to parallel and relive the overload (if any caused).

Another example following inter-substation communication can be towards coordinating tap-changing distribution transformers, down-stream voltage regulators and up-stream capacitor banks. Possibilities for developing transfer trip schemes in distribution systems with lightly meshed distribution network implementation can also be realized. Also smarter back-feed of certain portion of the laterals in a distribution network, following upstream fault in a main feeder, can also be potentially implemented. The design, testing, and implementation for all of the above identified schemes, if realized on distribution network will follow on similar lines as described in this paper for ABTS.

VIII. Conclusions

This paper comprehensively reviews different ABTS methods used for primary auxiliary bus supplying motor loads and proposes to extend it to primary distribution substation. The possibility to enhance ABTS enabled through IEC 61850 IEDs has been established. A scheme for ABTS in an existing substation while adding a third transformer in parallel to existing transformers has been developed. The novelty comes from being able to use an automation scheme based on IEC 61850 standards to defer network reinforcements and manage fault levels in primary distribution substation. The proposed scheme has been implemented, tested and made operational in one of the 11 kV primary distribution substations. Future implementation pathways, following inter-substation communication, have been briefly discussed.

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