21, rue d'Artois, F-75008 PARIS
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The Substation of the Future

R. HUNT, T. SMITH, B. FLYNN
GE Grid Solutions
USA

SUMMARY

The growing trend for protection and control and substation automation is the digital substation. This is generally understood to mean fully implementing process bus. While adopting process bus provides great value, it is only a stepping stone. The long-term goal must be to move away from the current single-purpose, hardware-based protection and automation systems and replace them with a software-defined control system running virtual services: a digitally enabled substation.

A digitally enabled substation is necessary to enable substation systems to adapt to the new realities of changing distributed energy resources impacting feeder power flow, voltage, and protection functions, and the changing operating requirements brought on by widely distributed, inverter-based resources. Wind, solar, battery storage, and EVs maybe be connected anywhere to the grid, and by different owners often concentrated in areas negatively impacting the traditional grid. Operators and control functions must plan for and adapt quickly to changes in available resources and load flows. Utilities, systems owners and a host of new DER stakeholders will need to be able to roll out new applications and access an increasing amount of grid data to optimize their investments. Old schemes will need to be adapted quickly and reliably throughout the entire system.

The only way to provide the adaptability and flexibility required, with the speed required, is using an application driven, hardware and vendor independent ecosystem, where the substation is a critical control point to manage and improve power system operations.

KEYWORDS

Process bus, IEC 61850, distributed energy resources

richard.hunt@ge.com

THE SUBSTATION OF THE FUTURE

Figure 1 is the substation of the future. This substation is:

Fully modular, in that individual logical parts of the system, even at the primary equipment, have a defined functionality and a defined interface between different modules.

Fully digital, in that all connections between the modules uses communications as defined by the IEC 61850 Standard.

Virtual, in that every control and monitoring function is an independent application operating in a local application server.

There are two main reasons to adopt this design for the station of the future. The first is the ability quickly and efficiently design, build, commission, and operate the substation, eve if that process involves the refurbishment of existing primary equipment. The second reason is the growing need to quickly develop and rollout new applications to meet the changing needs of power system operations as inverter-based resources, like wind, solar, and battery storage, become more prevalent, especially at distribution. The major goal is to change the mindset from operating the substation better, to using the substation to operate the power system better.

Modular design is necessary to provide the speed and the path to adopt this virtual future. Digital communications is necessary to ease connections between modules and devices. But the real key is the virtual applications. Applications can be developed by competent developers, including the utility, and pushed out the all substations. This is conceptually moving away from the dedicated hardware and firmware solutions of today to using an application-driven, hardware and vendor independent ecosystem.

It is also the case that future substations will need to be tightly integrated with systems outside the substation, acting as a data collection point or data concentrator, and a control / decision making point on the power system. Substations will be tightly integrated with distribution automation systems and may be the first line control point for these systems. Substations will interface with various microgrids, to aggregate data and issue control commands. They could interface with SCADA systems and cloud-based services for applications such as asset performance management, digital twins for testing, and dynamic line ratings. Substation applications could also use intelligence and system modeling for dynamic settings and local state estimation. The key is the ability to define and produce these applications and push them out to the local application servers.

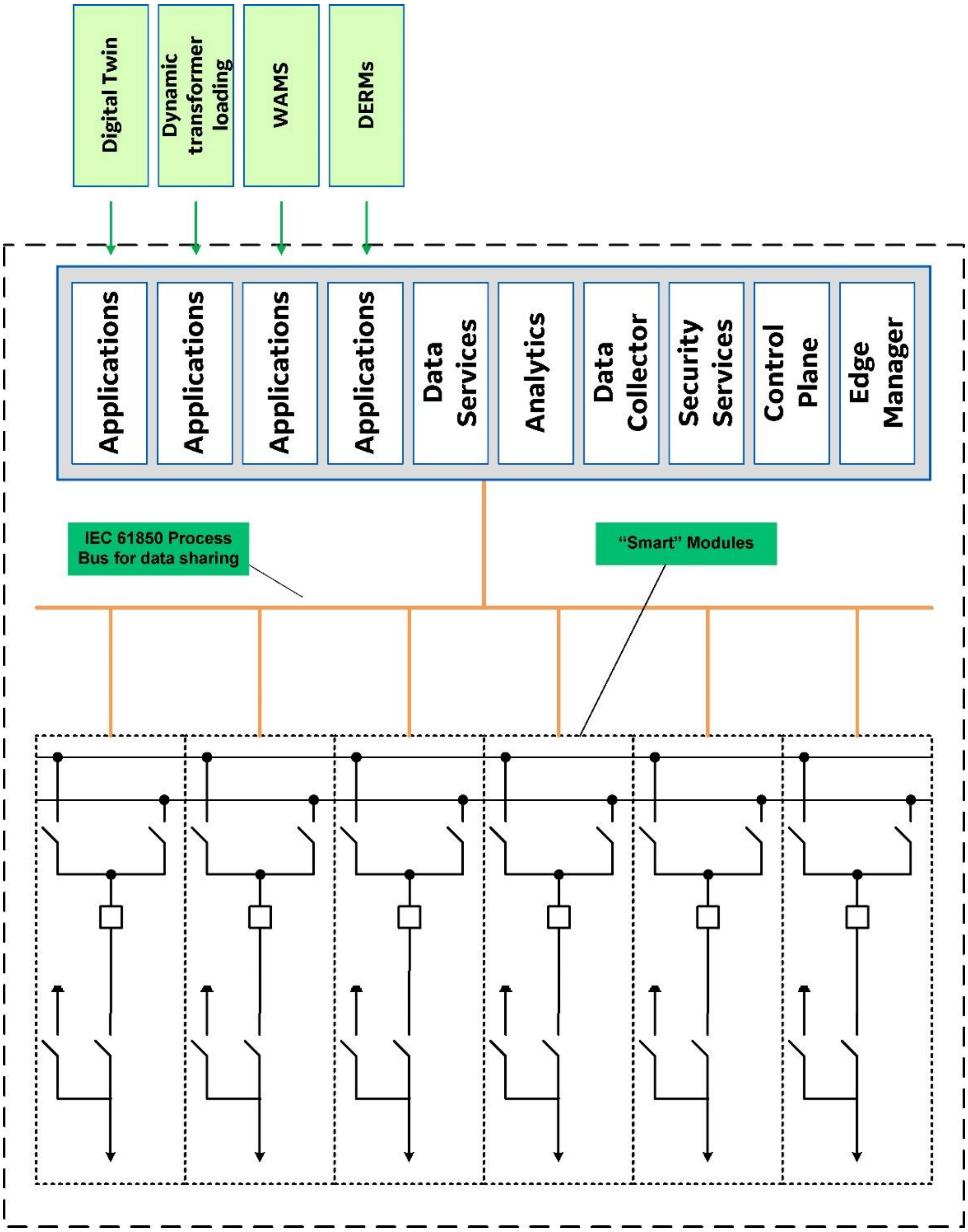

Figure 1: The Substation of the Future

The key parts of this substation of the future design to discuss are primary equipment modules, which are the basic physical building blocks; process bus, which is the communications network for this design; and the local application server, where the virtual applications run.

Smart Primary Equipment Module

The smart primary equipment module is a complete packaged solution for a portion of a substation. An example is in the complete feeder bay of Figure 2. This bay is a physical module and a virtual module, with a defined functionality (a double bus primary feeder bay) and defined interfaces in the bus structure for the physical interface, and process bus communications for the virtual interface. This module consists of all the primary equipment supplied as a single containerized or platformed unit. The primary equipment is "smart" – that is, fully digital. Only digital communications using IEC 61850 will be used for status, control, and measurement for the bay. The circuit breaker and isolator

switches will also be “smart” devices, as there will be no physical wiring interface for external use, only digital communications outputs provided from the equipment.
Digital instrument transformers (DITs) will be tightly integrated into this bay. DITs are non-conventional instrument transformers, like Rogowski coils, fiber optic CTs, and optical CVTs, that provide a natively digital output of sampled values as per IEC 61850-9-2 [1].
Beyond the process bus communications, the virtual part of this smart module is the application functionality. This functionality, in terms of automation control, and protection, can be predefined as an application to push into the local application server. Or it could be a pre-defined library module in the protection and automation part of the local application server.
The simple definition of the smart primary equipment modules, then, is a pre-designed and pre-built module delivered with all the primary equipment, a defined digital interface for all data for status, control, and measurement, a defined power system functionality, and a defined virtual control and protection functionality. Modern gas insulated switchgear sections are generally very close to being a smart primary equipment module, if they use DITs and process bus communications. There are ongoing projects to develop a similar functionality for air insulated switchgear.

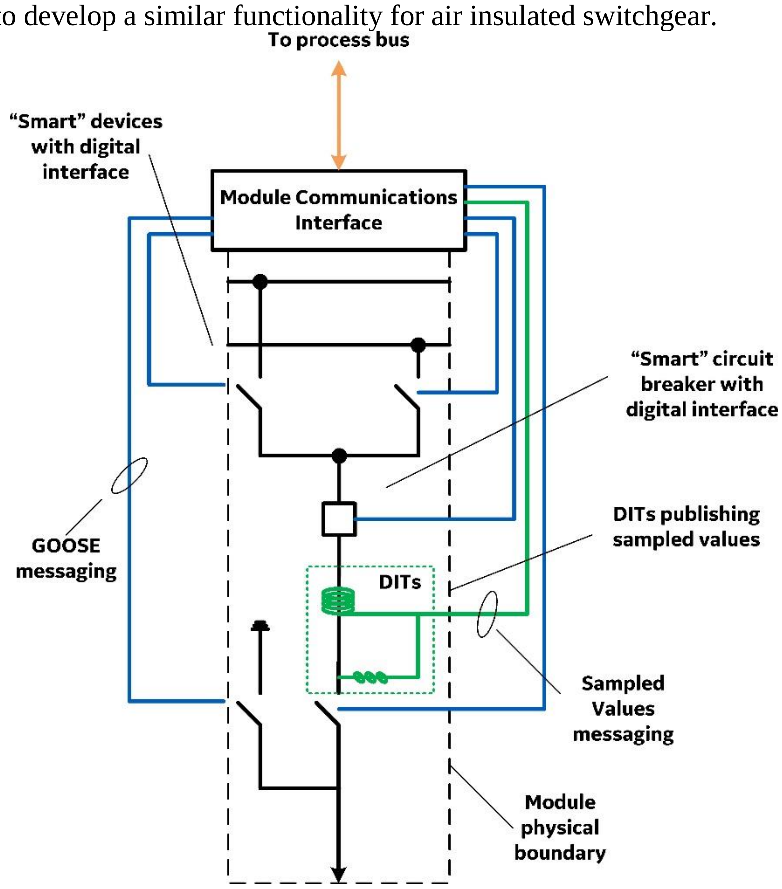

Figure 2: “Smart Module” concept

Process bus

Process bus is essentially distributed I/O for protection and control. Digitization takes place in simple I/O devices integrated into primary equipment, using the data models and message formats of the IEC 61850 Standard. Digital sampled values (SV) representing primary current and voltage, along with status and control signals, are transmitted through a communications channel to protection and automation equipment, or in the case of this substation, the local application server. Process bus facilitates flexibility and adaptability because the basic data for state, status, and control of the substation is available on the process bus network. Any application connected to this network can subscribe to the data, without impacting other devices or applications, and without connecting to the primary equipment.

The reason to use the IEC 61850 Standard for communications is to provide a “future proof” digital substation architecture that can be easily configured, updated, and maintained. Configuration of a process bus system is easily verified through standard tools, as the data models provide self-description of the data being sent. The majority of messages are event driven, using a multicast publish-subscribe model. This means adding a device or application is a matter of publishing messages to the network and subscribing to the appropriate messages already on the network. It is these features of IEC 61850 communications that make a process bus solution future proof. Any device or application supporting IEC 61850 can connect to the network and interoperate with any other device on the network while using the same configuration tools.

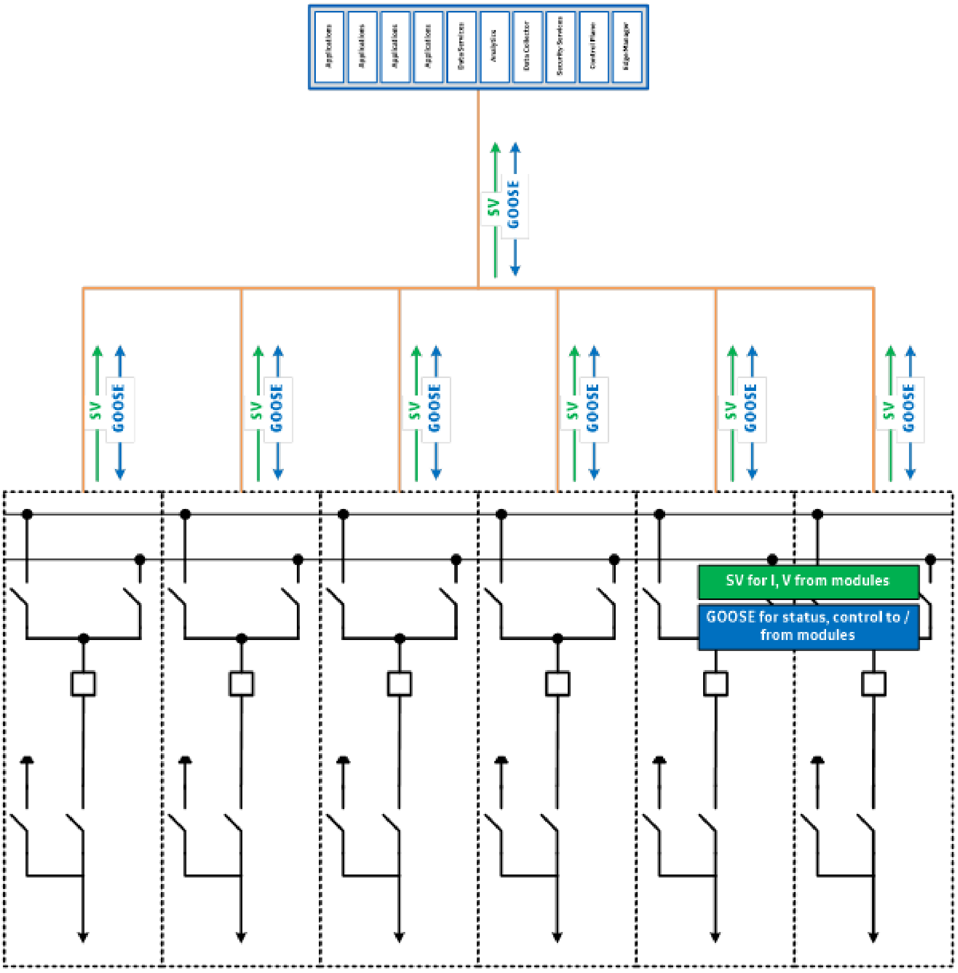

Figure 3: Process bus

Local Application Server

A local application server is a processing platform running software services using a services or container-based architecture. This is the heart of virtualization. Every application is developed as a service, running independently of each other, each entirely in its own container, as in Figure 4. Data can be shared across or between applications as necessary, so functions like the security manager and control plane are shared. This application server runs applications for use inside the substation such as control and protection; applications to connect the substation with devices and systems coupled with the substation such as DER management, fault detection and isolation, microgrid integration; and connections to cloud applications and utility system operations.
The key requirement is the ability to quickly specify, prototype, test, and rollout applications as needed for power system operations. As individual applications are independent, they can be rolled out

to an in-service application server without impacting the already running applications in this server. This provides for quick and simple upgrades without risk.

The general concept of a local application server has been commonly known as “centralized protection and control”. There are many permutations of how centralized protection and control can be implemented, as described in the “Centralized Substation Protection and Control” report developed by the IEEE Power System Relaying Committee. [2]. However, to date, centralized protection and control has only focused on internal substation applications. A local application server provides these internal applications, as well applications to connect and interact with the wider power system.

Figure 4: Application Server concept

Substation edge device

The actual architecture of the local application server can take many forms. One form is that of the substation edge device of Figure 5, a container-based server running both a non-real time operating system, and a real-time operating system for protection functions. A substation edge device is generally built from hardware already developed for use in substations. The design process is simply a matter of a new operating system to provide software containers. [3] The benefit of this design is working off of hardware that is already designed for the substation environment.

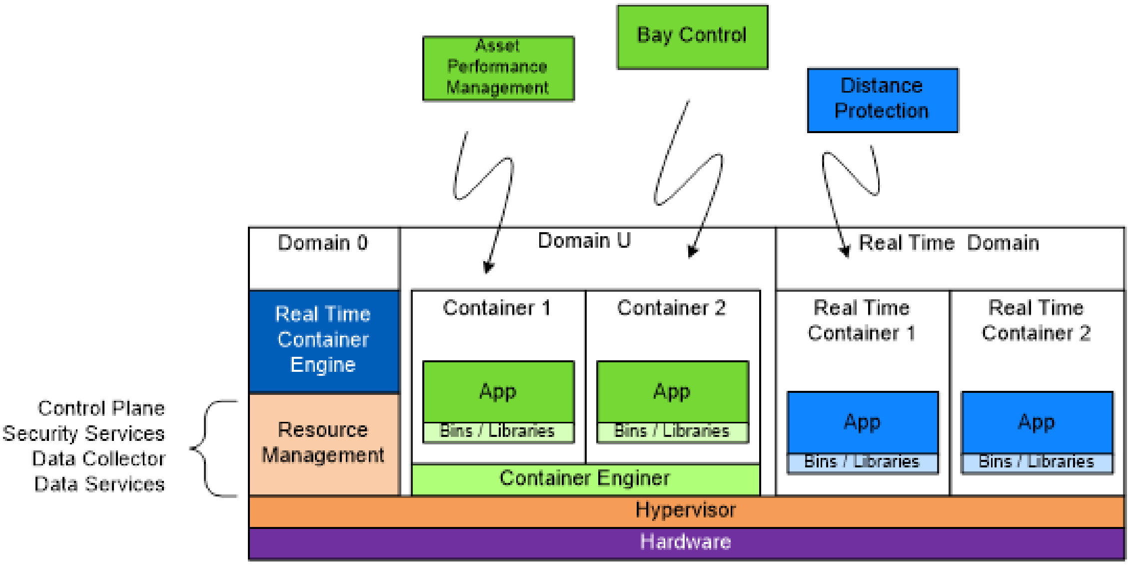

Figure 5: Substation edge device

Card module server

Another option for a local application server is a card module sever, as in Figure 6. In this model, application cards have processing capability, and add specific functions. The benefit to this concept is the ability to back up functionality and move it to other application cards based on system load or on card failure. The downside is the need to develop applications specifically to run on the card modules, and the need to design rugged architecture for the substation environment.

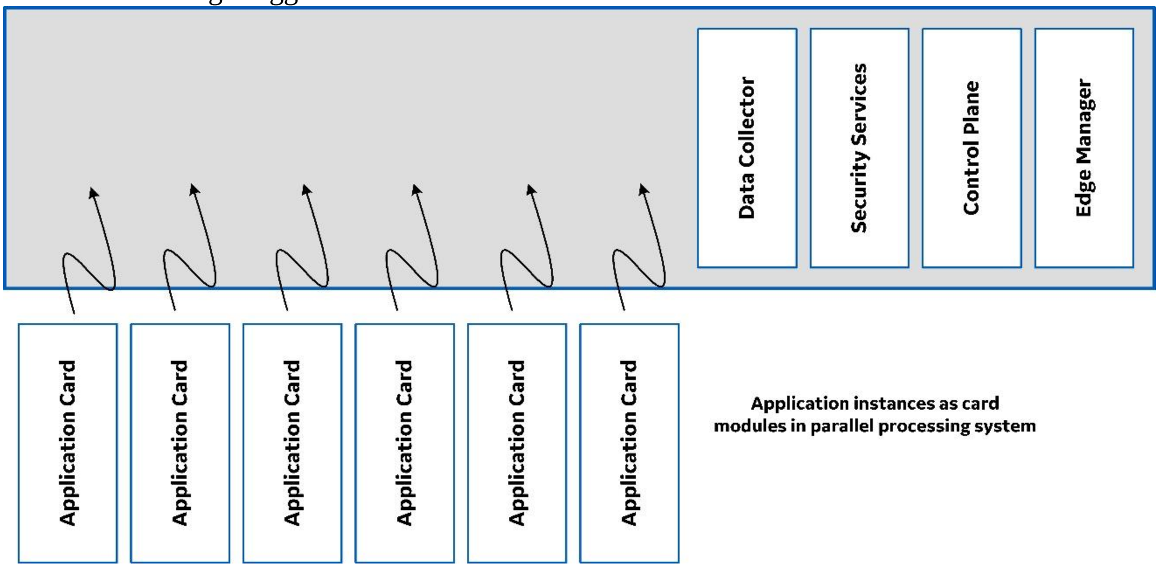

Figure 6: Card module server

Multi-core processing platform

Another concept is to use multi-core processing industrial computing platforms, as in Figure 7. Every function, or class of function, can be run on its own core, to isolate processing requirements between devices. This type of application server has been successfully applied. The detriments are that applications must be explicitly developed for the multi-core platform and finding a computing platform that is environmentally rugged enough for the substation.

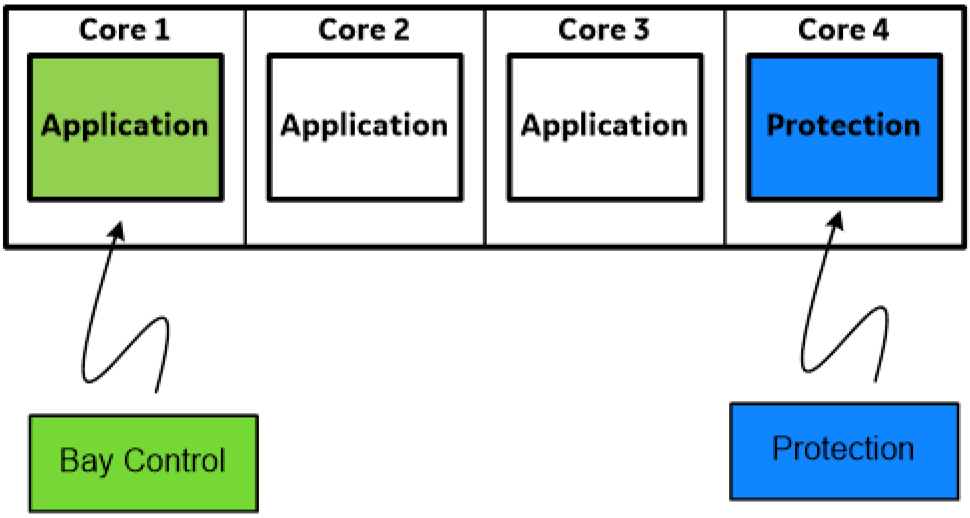

Figure 7: Multi-core processing platform

Local cloud application server

A fourth option is to use local cloud software, as in Figure 8. The cloud software runs inside the substation only, running on multiple parallel processing platforms. Applications are developed for and loaded into the cloud software. The cloud software can run multiple parallel instances of all applications. The cloud operating system will spread application loading across all available processing platforms and will rebalance the loading on hardware failure. The use of a local cloud has the great advantages of being able to borrow tools and concepts from many other industries, completely abstracting functionality from hardware, and providing for simple replacement of failed hardware without requiring shutdowns or commissioning. The detriment is finding processing platforms that are suitably rugged for use in utility substations.

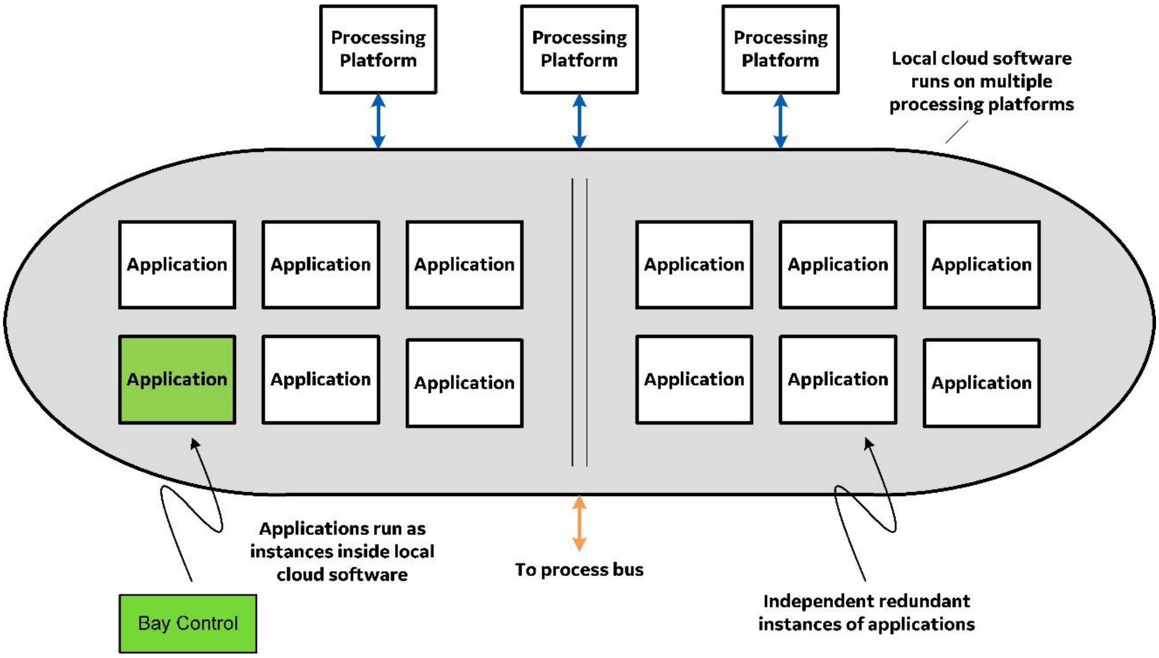

Figure 8: Local cloud

Redundancy

One consideration of the using a local application server is that of redundancy for reliability, a topic discussed in detail in the “Centralized Substation Protection and Control” report [2]. The substation edge device, card module server, and multi-core processing platform will require redundant devices for reliability. The local cloud application server natively provides for redundant hardware and provides redundancy of application in the cloud software.

WHERE WE ARE TODAY

The substation of the future uses fully modular development of primary equipment and the applications for a substation. The challenge is how to get from the substation of today to the substation of tomorrow. To define the process, it is necessary to understand the baseline of how substations are designed and built today.

The key assumption in this discussion is that new substations are fully digital substations, in that all analog interfaces are digitized directly at the source, and all data is published digitally under the IEC 61850 Standard.

Modular design of I/O for bays

As opposed to the smart primary equipment modules discussed in Section 0, the substation of today is built with primary equipment and secondary equipment as separate items. Every bay is designed for a specific substation and built directly on site. Separate I/O devices are installed to digitize the control, status, and measurements at the primary equipment. I/O devices are likely to be installed in marshalling kiosks in the switchyard, with field wiring installed from the primary equipment to the kiosks, as in Figure 9. The results in a modular design for the secondary I/O devices, not for the bay as whole. The marshalling kiosk is installed in the switchyard, and copper cabling is pulled from all primary devices to this kiosk. This is modular design of the process bus system, but not the physical part of the substation.

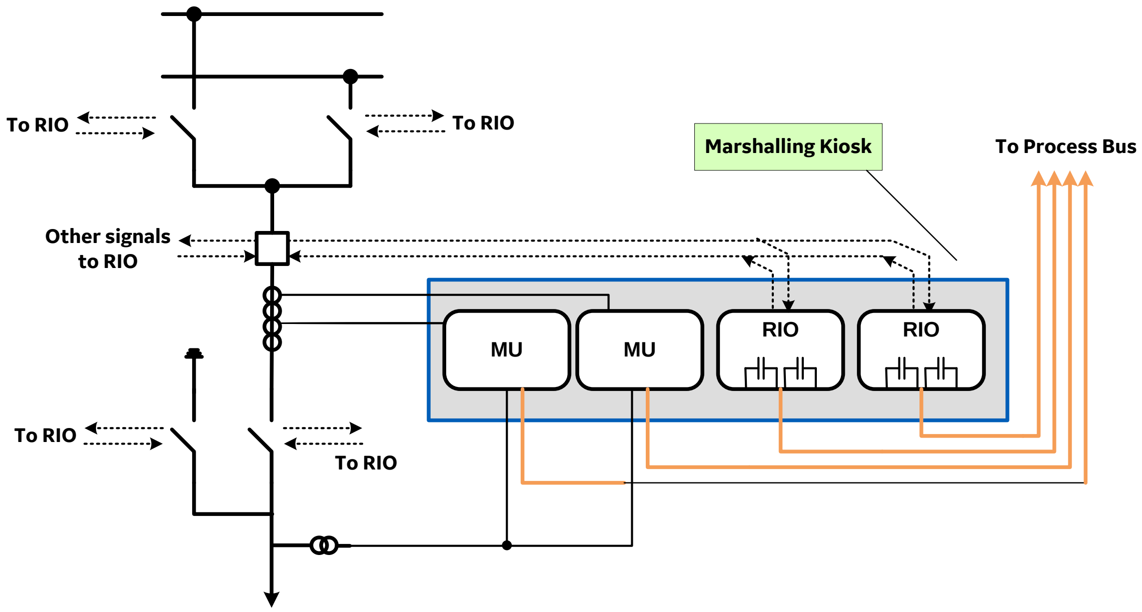

Figure 9: Bays today

Process interface units (PIUs) will exist close to the primary equipment and will be the interface between the electrical physical world and the digital world. Their role will be to publish information from the primary equipment and to control the primary equipment from digitized control signals on the communications networks. These PIUs will control circuit breakers and switches, will also be connected to traditional current transformers and voltage transformers, and will publish both equipment signals and digital sampled values to IEDs for protection and operation purposes. The PIUs shown in Figure 9 are merging units (MUs), that convert analog measurements to digital sampled values; and remote I/O modules (RIOs), that are contact inputs and outputs for status and control. This means that circuit breakers and isolators aren't natively "smart", as the analog to digital conversion requires a separate device that must be installed and wired. However, this design can be used for any substation installation, and is an easy retrofit solution when primary equipment is not being replaced.

Individual application devices

Substations of today are still built around individual application devices for zones of protection, for automation, and for SCADA control, as in Figure 10. Every zone has a relay and bay control unit (BCU); and may have redundant relays for reliability. Station level devices like gateways, HMIs, and substation controllers coordinate all control and reporting action. One challenge with this architecture is the number of devices that must be managed. Another challenge is adding new functionality, or enhancing existing functionality, means upgrading multiple devices in one substation. These devices also, today, have integrated hardware and firmware, so new enhancements or applications means updating the existing firmware and configuration, which can be an involved process, especially as re-commissioning may be required.

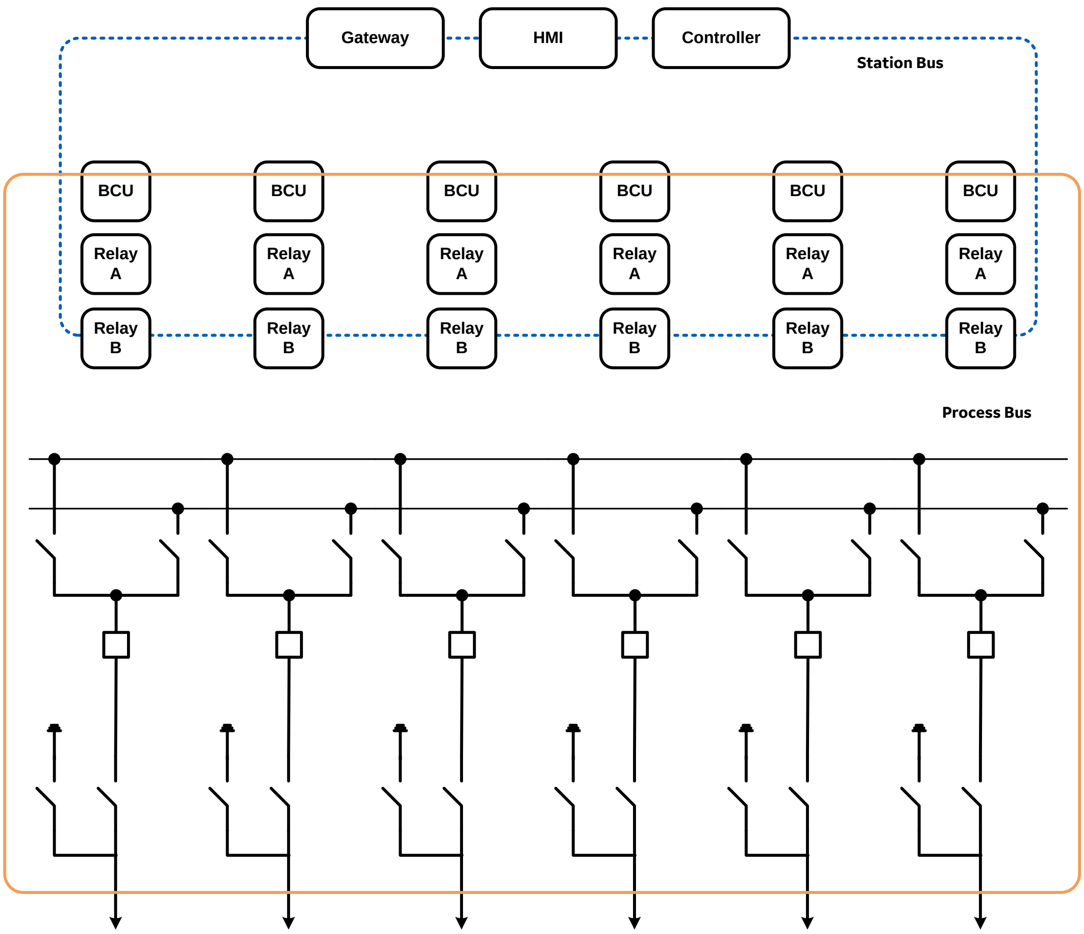

Figure 10: Individual zones of protection / station devices

DITs as application specific devices

DITs have been available for decades, but wide spread adoption has been slow, mostly due to lack of experience with DITs, and low availability of process bus-capable IEDs. The application of DITs is starting to become more common, mostly in the pilot project or technology evaluation stage. The result is DITs are being installed as retrofit or add-on devices to existing substations and primary equipment designs. They may require their own mounting structure, as in Figure 11, or may be a temporary installation, as in Figure 12. In these cases, the benefits of integrating DITs, such as size, weight, mounting locations, and performance, are not fully realized. [4]

Figure 11: Stand alone DIT

Figure 12: Temporary / pilot project DIT

Baseline of today

The baseline of today, then, is straightforward. Fully digital substations are the growing trend, adding I/O devices such as MUs, RIOs, and DITs directly to primary equipment as part of the design and build process. Individual devices are used for control and protection for each zone of equipment. This step starts to take advantage of digitalization but is not true virtualization of functions.

NEXT TECHNOLOGY STEPS

To go from the basic digital substations of today, to fully modularized and virtualized substation of the future, is likely to happen in intermediate steps, as utilities gain confidence with both the concept and available technology. While much of the technology and tools can be borrowed from other industries, the hardware that applications run on must be designed for the rugged environment of the utility switchyard, and the expected 20-year minimum service life.

Advanced gateway application server

One next step is an advanced gateway application server as in Figure 13, and products designed on this concept are becoming available in the market. This is the first step to becoming the substation edge device described in Section 2.3.1. The hardware is built to meet the environmental requirements of the substation, as defined in the IEEE 1613 [5] and IEC 61850-3 [6] Standards. Using proven, ruggedized hardware, this gateway application server uses a container-based architecture to provide standard gateway applications like SCADA controls services and an HMI. Other substation focused applications like phasor data concentrators or microgrid control can be developed as separate services and added at a later date, without impacting the already developed and already running applications.

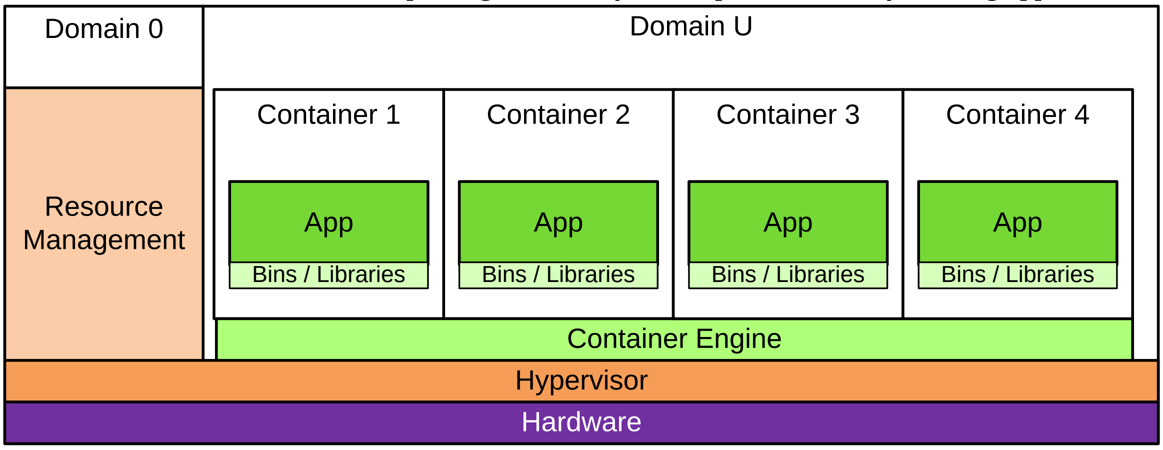

Figure 13: Container-based gateway as application server

The first pass at the advanced gateway application server does not include the real-time operating system necessary to run protection applications. This is in part due to technical considerations about running real-time and non-real-time operating systems in the same device. This is also in part about utility confidence in the solution, and the desire for the protection group and the SCADA group to have full ownership of their own devices.

Multi-zone protection relay

Another next step is a multi-zone protection relay of Figure 14, built on top of an existing transmission-class protective relay hardware. This type of device can run multiple instances of an entire zone of protection, using existing, proven algorithms, running on the same proven operating system. This is relatively simple concept to develop off of existing hardware platforms. Once relays become optimized for process bus, the only limitation to the number of protection zones is the number of SV streams, and the capabilities of the processor. Busbar protection relays are coming on to the market that accept up to 24 SV data streams, so the complete protection of small substations in a single multi-zone relaying platform is possible.

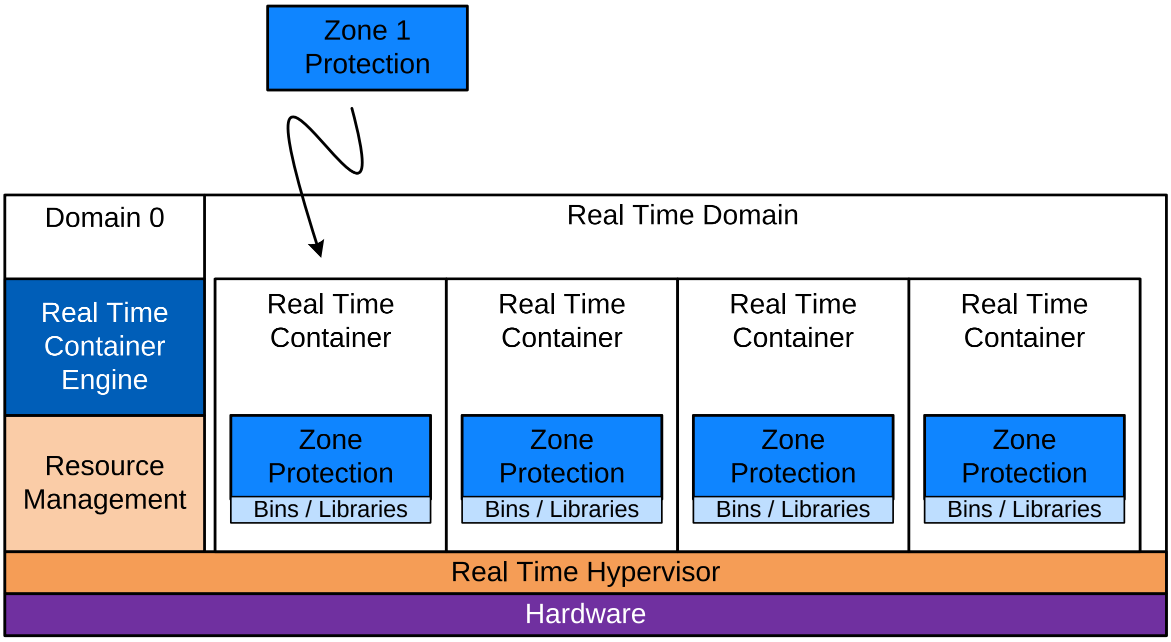

Figure 14: Multi-zone protection relay

Integrated DITs

A third next step, which is already available today, is to fully integrate DITs into circuit breakers. This reduces the footprint for substations, the infrastructure for handling cables, and the number of cables required. The examples of Figure 15 show DITs integrated into live-tank and dead-tank circuit breakers, respectively, in air insulated switchgear. It is also possible to provide DITs for gas insulated switchgear as well, resulting is smaller switchgear, and fewer devices under the insulating gas.

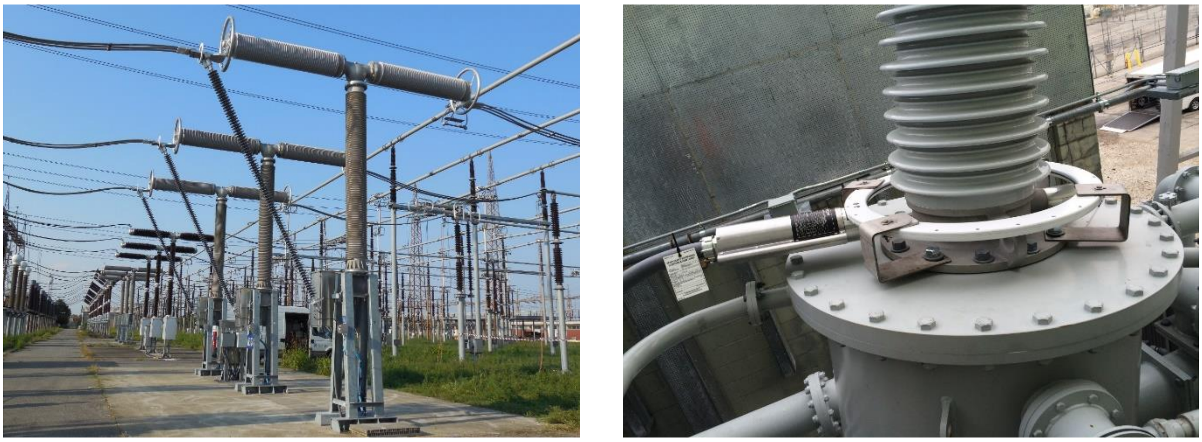

Figure 15: DITs integrated into primary equipment

Next generation substation

The next generation substation, the intermediate step between the basic digital substation of today, and the fully modular and virtual substation of the future, is illustrated in Figure 16. An advanced gateway application server, and two multi-zone protection relays for redundancy, and process bus-enabled equipment. DITs integrated into switchgear in new applications.

The devices to support this architecture are available today, or becoming available today, so design will become the standard architecture for substations.

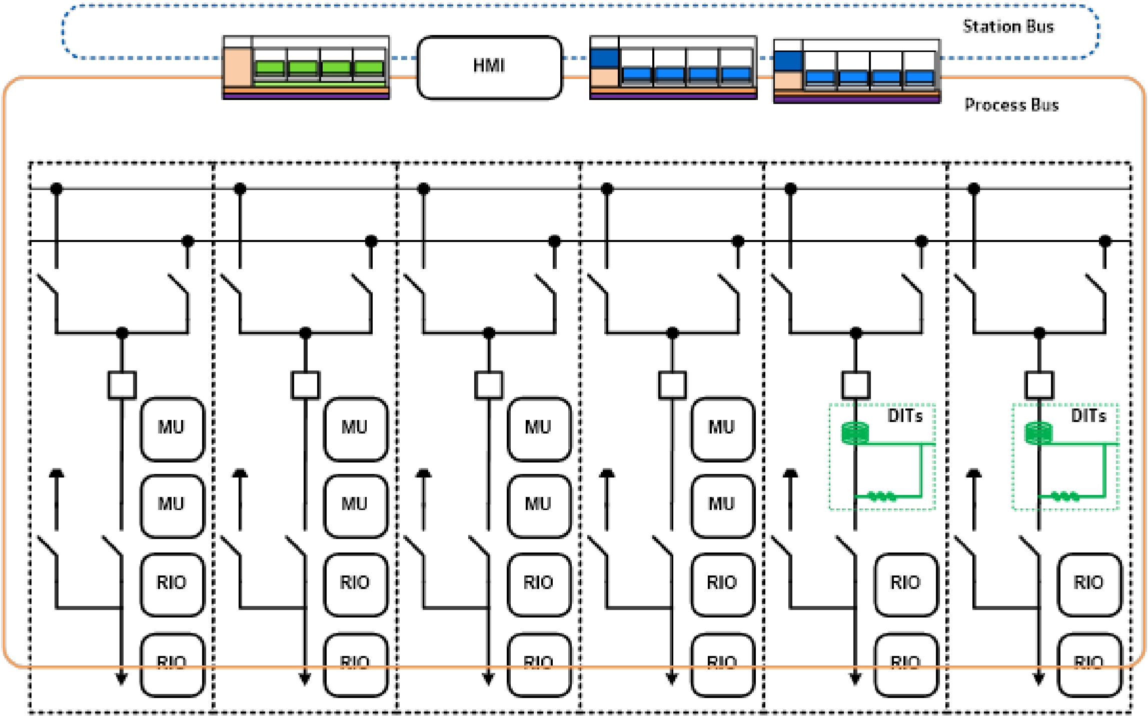

Figure 16: Next generation substation

APPLICATIONS ENABLED BY THIS CONCEPT

One step for putting the substation of the future in place is installing the building blocks in place for a modular, virtual substation. Another step is defining and developing the applications. Applications can include asset performance management, a system digital twin for testing, integration into distribution automation, microgrid control and integration, machine learning for dynamic settings, even local state estimation. The possibilities are defined by the needs of a specific utility. All data from the substation is available at the local application server through process bus communications, and the application server can collect data from external sources such as distribution automation devices and SCADA systems through standard wide-area communications.

Adaptive transformer loading

The adaptive transformer loading illustrated in Figure 17 is simply the idea of maximizing the capacity of power transformers during changing system conditions. The concept is to take transformer monitoring data, including winding temperature, hot spot data, and dissolved gas analysis, combine this with load data, predicted load data, and meteorological data. The application then uses analytics to control the cooling system, to pre-cool the transformer before predicted higher load occurs. This permits the maximum capacity possible out of the transformer, while extending the service life by reducing the rise, and reducing the time, that the windings experience a thermal overload.

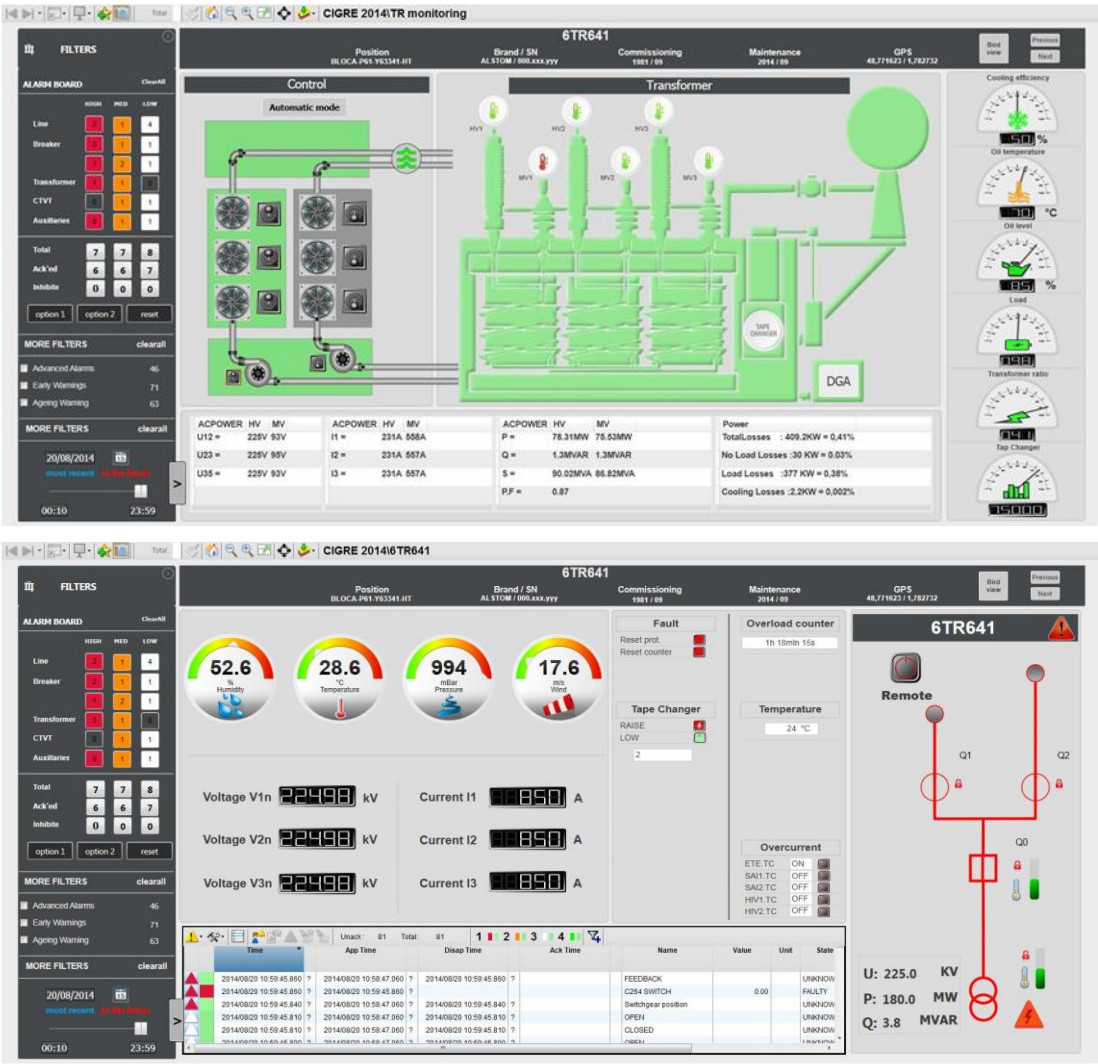

Figure 17: Adaptive transformer loading

WAMS

One goal of the substation of the future is to use the substation to improve power system operations. This means the substation must be a key piece of a Wide Area Monitoring System (WAMS) for both transmission and distribution. The WAMS application at the substation provides critical data through a larger deployment of phasor measurement units (PMUs) and MicroPMUs across the grid, combined in a visualization like Figure 18. The system includes secure access and phasor data management in substations and provides new tools for automation, operators, and engineers.

Possible uses for this data, or variations of this application, include near real-time stability monitoring, sub-synchronous oscillation detection and dampening, system disturbance monitoring, short circuit capacity calculations, fast voltage stability assessment for transmission corridors, and islanding resynchronization and blackstart.

Figure 18: WAMs data

DERMS

The changes to power system operations are due in large part to the future high penetration of distributed energy resources (DERs). DER data, control, and optimization will be part of future substations, especially for utility grade resources. This data will play an important role in understanding, managing and planning an increasing complex DER portfolio. Applications running in the substation will determine the mitigation steps to reduce negative impacts involving voltage stability, grid capacity, reverse power flow, unintentional islanding, short circuit current levels, and more.

Substations will need to provide critical data for real time analysis and control algorithms, through a DER Management System (DERMS) running as an application, as visualized in Figure 19.

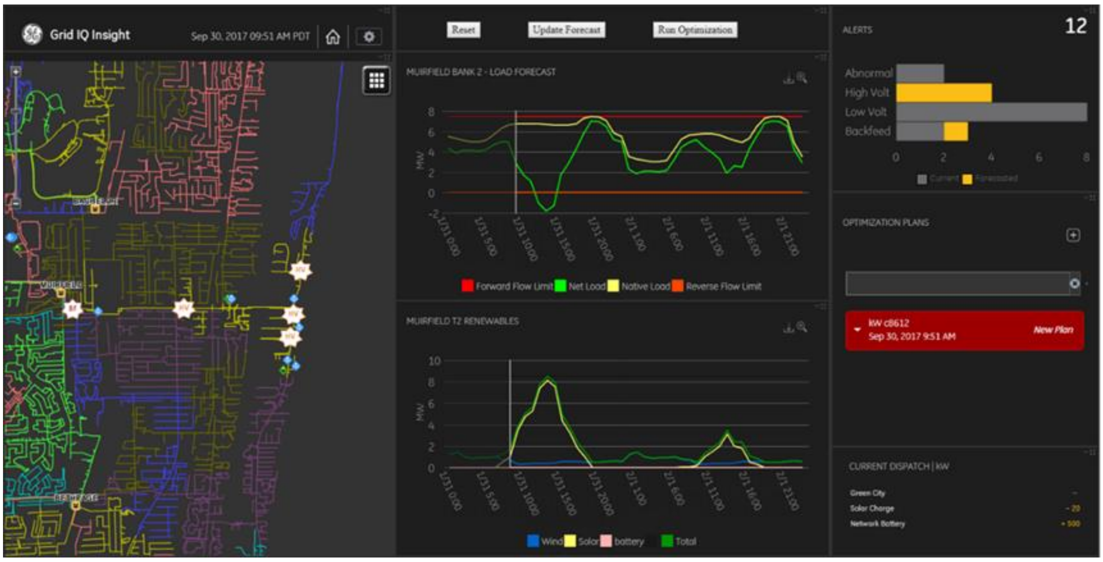

Figure 19: DERMS overview

SUMMARY

The substation of the future is completely modular in design, completely digital in communications, and fully virtual in functionality. This allows faster, more repeatable, lower cost design, build, and refurbishment of substations of substation control systems. The important ability is to quickly develop control applications to meet the changing requirements of power systems. The first steps on this path are modular design of process bus systems, and the use of the advanced gateway application servers and multi-zone protective relays becoming available in the market.

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