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Lessons Learned Implementing an IEC 61850-based Microgrid Power-Management System

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SUMMARY

A North American oil refinery recently improved on-site power system reliability by installing a new utility ring-bus substation, a new utility interconnect substation, four new medium voltage distribution switchgear lineups, and separating two on-site 14.9 MVA cogeneration units onto dedicated buses. The refinery also upgraded all of the plant protective relaying to microprocessor-based systems.

New load added to the system caused a generation deficit when islanded from the local utility. The project team implemented a power management system to preserve critical loads (and shed non-critical loads) when the refinery microgrid is islanded from the utility.

The project team implemented power management controls in existing devices which were already using IEC 61850 GOOSE messaging for transfer tripping, breaker failure, remote synchronizing, and islanding detection schemes. New hardware for the power management system included four controllers occupying a total of two rack-units in existing racks.

The project team performed thorough Real Time Digital Simulator (RTDS) testing to validate system operation for designed transitions and anticipated equipment failure modes. The team performed hundreds of tests to verify the scheme operated according to its specifications.

RTDS tests uncovered some surprising performance issues, which were corrected ahead of system installation. This saved commissioning time and expense and improved the overall reliability of the system. This paper presents lessons learned for consideration by other potential users of these technologies for microgrid control and power management systems.

KEYWORDS

IEC 61850, GOOSE, Refinery, Power Management, RTDS, Microgrid, Dynamic Testing, Lessons Learned, Load Shedding, Peer-to-Peer.

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INTRODUCTION

A client oil refinery recently sponsored projects to improve on-site power system reliability. Along with other work, the refinery upgraded all of the plant protective relaying to microprocessor-based devices that support IEC 61850 GOOSE [1] messaging. The refinery also added new process electrical loads, increasing the plant total load above the capacity of two on-site 14.9 MVA aero-derivative combustion turbines (CT). Heat recovery from CT exhaust gases creates refinery process steam, so continuous unit operation is critical for both electrical and process loads. In the past, the site electrical load total had been less than the unit nameplate rating. With the newly added loads, a power management system was required to shed non-critical loads, preserving CT operation and their vital steam production during island operation.

Figure 1 is a simplified view of the plant electrical system and 46kV utility interconnect. While there is presently no renewable generation on-site, the requirement of stable operation through islanding and paralleling contingencies along with the power management function creates a de facto microgrid.

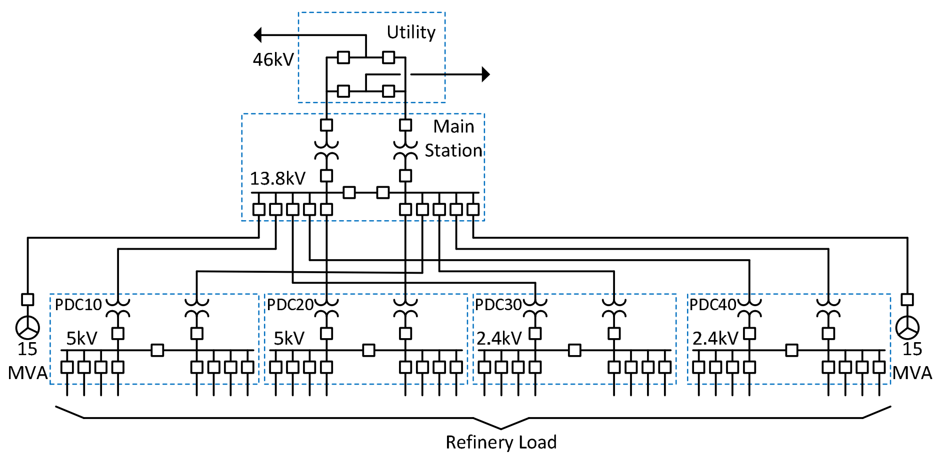

Figure 1: Refinery Electrical System

POWER MANAGEMENT SYSTEM OVERVIEW

Earlier projects had installed microprocessor-based protective relays and an Ethernet network dedicated to electrical protection and SCADA. These components provided the infrastructure needed for the new power management system. The project team had implemented IEC 61850 GOOSE messaging for transfer tripping, breaker failure trip, remote synchronizing, and islanding detection schemes in the previous projects. The team had applied additional consideration for redundancy, speed, and reliability in the protection Ethernet network design. The network included two single-mode rings to provide the needed redundancy. VLANs and Classes-of-Service were used to achieve the necessary speed and delivery requirements.

The power management system required four new controllers that handle inputs from around the refinery and trip selected loads in the event of a separation from the utility 46kV system. The power management system measures import power at the point of interconnect and calculates the amount of load to be shed in the event of an islanding event. Each contingency breaker, load breaker and topology breaker is monitored individually (Figure 2). Using an HMI and an input table, plant operators prioritize the processes to be shed if a separation occurs. The system automatically trips breakers according to the user-selected priority to correct the power deficit caused by separation. The system monitors the microgrid frequency after the initial event and continues to shed load, if required, until grid frequency recovers.

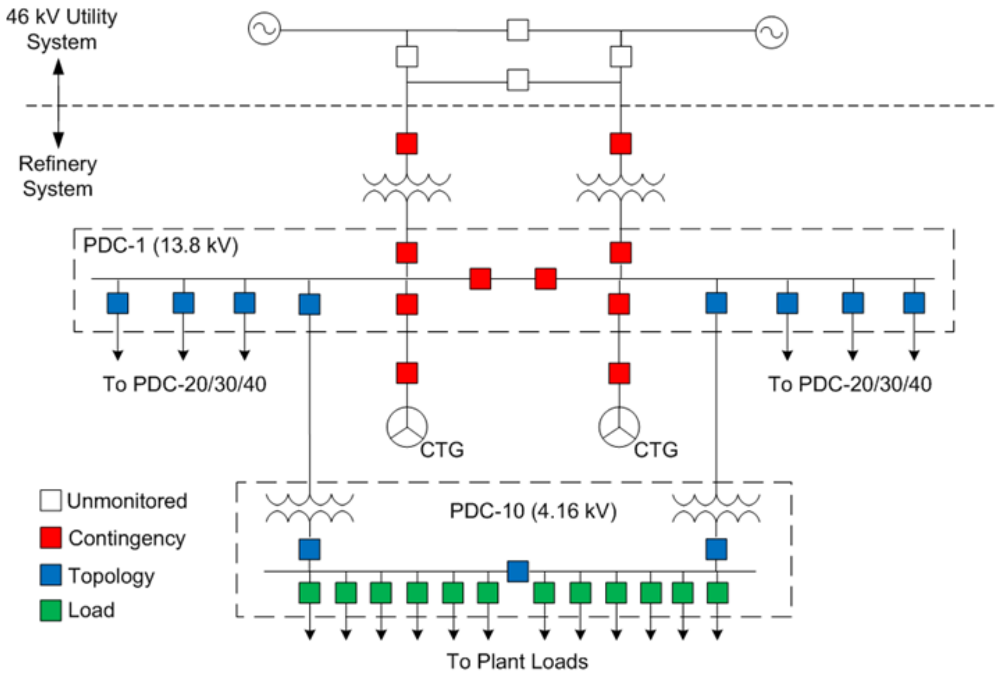

Figure 2: System Monitors and Controls Several Plant Breaker Types

SYSTEM TESTING

Due to the critical nature of the power management system, we performed thorough Factory Acceptance Testing (FAT) to validate system operation for designed power system contingencies (islanding, paralleling, and various loading levels). We also identified routine non-contingency events that required performance testing to prove that the system would handle those situations gracefully. Non-contingency events tested include network failures, losses of device power, device configuration changes, and others.

We selected RTDS testing for FAT since it would not be practical to exercise expected plant contingencies during commissioning. RTDS testing accurately represents system dynamic performance and permits validation of numerous system contingencies without disturbing operation of the plant or risking damage to valuable equipment or loss of production time. For efficiency, we determined not to test a full mock-up of the plant power management system, but we did select a test configuration that included one or more of each critical breaker relay type (contingency and load) and representation of all protective device types. This decision was important for reasons described below.

The site commissioning tests included full connection and configuration tests. Functional testing was very basic: a series of nine islanding events during a refinery maintenance outage where the refinery load was represented using three-phase test sets.

LESSON 1: ACCURATELY CHARACTERIZE THE SYSTEM

To prove that a power management system could detect contingencies and shed load quickly enough to preserve stable operation, we first developed a software electrical model of the system in a popular phasor-domain power system modeling package. By its nature, system performance is dependent on dynamics of the CT generators and electro-mechanical plant loads interacting with the power management system. The project team performed generator dynamic model validation so that accurate machine characteristics would be available. These characteristics were used in both system definition (in the phasor-domain model development) and in development of the time-domain electrical model to support RTDS testing.

System definition modeling identified that the refinery generators would become unstable, or trip offline for self-preservation, after as little as 30 cycles from certain initiating events. For conservatism, to produce operating margin, improve the chances of recovery, and possibly reduce the amount of load shed, the power management system produces control signals to shed load in under 10 cycles, in most cases.

Without dynamic model validation tests at the beginning of the project, system definition would have needed to depend on typical values for similarly sized machines, reducing confidence in both the performance definition and RTDS testing results.

LESSON 2: THOROUGHLY TEST SYSTEM OPERATING MODES

The plant and local utility system topology produce a high number of combinations for possible operating scenarios: Simple loss of grid connection; single-breaker failures; near-remote utility loads briefly served by plant generation; single-unit outages, etc. We produced detailed models that accurately represent the plant and near-system topology to reflect normal and likely-abnormal operating scenarios. Through these analyses, we produced a wide range of performance requirements and identified worst-case contingencies. These contingencies were documented and later run as RTDS scenarios during acceptance testing.

LESSON 3: INCLUDE AT LEAST ONE OF EACH DEVICE TYPE IN THE TEST

The client selected a single vendor for protective relays and power management processing platforms. As mentioned above, our testing regime employed one or more of each device type configured for operation in one or more of each critical breaker functional type represented in Figure 2 (contingency or load). The less critical topology breaker devices were simulated using an IEC 61850-capable test set. Through our testing, we learned that the vendor had implemented different update rates in IEC 61850 GOOSE-message look-up tables in different device types. This undocumented artifact produced unnecessary tripping operations in some instances, as well as significantly delayed tripping action in others.

We were able to design a work-around, perform our usual quality assurance review of the design, and functionally test the correction in the RTDS lab. It is possible that this problem might not have been discovered due to limitations of tests performed only in the field if RTDS-based FAT was not performed. Even had the artifact been discovered during commissioning, it may not have been possible to devise a correction and perform additional testing while maintaining an aggressive outage schedule.

LESSON 4: TEST SYSTEM FAILURE MODES

Given the value of refinery production, the economic cost of a system misoperation is incredibly high, particularly relative to the cost of individual system components. The owner would be dismayed to find that the failure of a $100 component caused the loss of millions of dollars of production.

For these reasons, we spent substantial time verifying secure operation of the power management system under a wide variety of failure and equipment-outage scenarios. Each individual device was power cycled under normal, non-fault conditions. Communication channels were interrupted and re-established. Online configuration changes were made (not recommended in normal practice). Some of these tests produced surprising—and undesirable—results.

During a power-cycle test, we learned that a protective relay power supply could continue to power the device processor and its production of GOOSE messages after the DC voltage wetting the breaker 52A input had dropped below a value necessary for the contact to be detected as closed. In its near-final act, the relay would publish a GOOSE message representing the apparent but erroneous breaker closed-to-open state-change. A few simple design changes were implemented to prevent this form of misoperation.

LESSON 5: IDENTIFY FAT AND COMMISSIONING TEST BOUNDARIES

Thorough acceptance testing of individual substation IEDs permits reduced commissioning tests when those identical systems are installed in the field [2]. We took advantage of the level of detail contained in our system FAT to limit functional tests during the system installation outage to only those that could not be tested before installation. Commissioning tests emphasized validation of communication channels, input/output functionality, and end-to-end operation of operator controls and alarm points. By nature, some limited overlap of testing took place, but this is preferred to leaving areas untested. Keeping commissioning tests succinct limits expensive field time by our testing team and reduces the impact the commissioning could have on the length of the scheduled plant outage. These save costs all-around while still delivering a thoroughly tested system.

LESSON 6: CAREFULLY PRESERVE SYSTEM TEST DETAILS

The RTDS-based FAT produced gigabytes of data of all sorts. System and device configuration files; oscillographic event records; data captures showing system I/O performance; wiring and connection diagrams; and photographs of systems under test are all carefully archived. If a system revision or plant addition is necessary, the test environment can be re-created for a small fraction of the original investment and new tests run. Regression testing to prove that modifications have not adversely impacted system performance is feasible, as are test additions to validate new features or functions.

CONCLUSIONS

IEC 61850 GOOSE messaging permits a high degree of flexibility in implementing new functions using existing Ethernet-based control systems. In this case, because the plant

Ethernet system existed and was designed with protection-grade performance, adding the equipment and signal paths for the power management system was substantially less expensive than it might have been otherwise.

RTDS testing this power management system added a level of design and performance validation that would not have been possible using traditional, 60Hz-based functional testing methods. The value of the refinery process made it worthwhile to invest in this grade of testing and to confirm that the microgrid could continue stable operation when an islanding contingency occurs.

Thorough lab testing of a complex control system permits the correction of discovered issues in a lower-stress environment than discovering and attempting to solve those issues during the condensed time-frames of an outage. Vendor support, peer reviews, and additional regression testing all become more feasible and effective, giving the engineer and the plant owners and operators greater confidence in the installed system.

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