

FINAL REPORT

Portsmouth Naval Shipyard Microgrid and Ancillary Services

ESTCP Project EW-201350

AUGUST 2017

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Ameresco, Inc.

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ACRONYMS AND ABBREVIATIONS

AAC	Annual Avoided Cost
ATTR	Alternative Technology Regulation Resource
BESS	Battery Energy Storage System
CAISO	California Independent System Operator
CHP	Combined Heat and Power
CMP	Central Maine Power
DG	Diesel Generator
DNP3	Distributed Network Protocol
DOD	Department of Defense
ERCOT	Electric Reliability Council of Texas
ESPC	Energy Savings Performance Contract
ESTCP	Environmental Security Technology Certification Program
FERC	Federal Energy Regulatory Commission
FLS	Fast Load Shed
GE	General Electric
GOOSE	Generic Object Oriented Substation Events
GTG	Gas Turbine Generator
HMI	Human Machine Interface
HRSG	Heat Recovery Steam Generator
IA	Interconnection Agreement
IED	Intelligent Energy Device
IEEE	Institute of Electrical and Electronics Engineers
ISO	Independent System Operator
ISO-NE	Independent System Operator for New England
kW	Kilowatt
LOC	Lost Opportunity Cost
LoU	Loss of Utility
MCS	Microgrid Control System
MISO	Midwest Independent System Operator
MPLS	Multiprotocol Label Switching
MW	Megawatt
MWh	Megawatt Hours
ms	millisecond

NAVFAC	Naval Facilities Engineering Command
NIST	National Institute of Standards and Technology
NY-ISO	New York Independent System Operator
PJM	PJM Interconnection LLC
PNS	Portsmouth Naval Shipyard
PVT	Performance Verification Test
PWD-ME	Public Works Department - Maine
RTU	Remote Terminal Unit
SCADA	Supervisory Control and Data Acquisition
SCP	Site Commissioning Plan
SOC	State of Charge

1.0 INTRODUCTION

The objective of this project is to demonstrate that the emerging technologies of Microgrid Control Systems (MCS) and Battery Energy Storage Systems (BESS) can be integrated with on-site generation at military bases to enhance the security and reliability of electric service to the base, provide valuable ancillary services to the electric grid Independent System Operator (ISO), and generate cost savings for the government.

This project uniquely integrates several innovative technologies to provide cost-effective solutions for military energy surety. It includes a 500 kW / 580 kWh BESS to assure power quality on base at Portsmouth Naval Shipyard (PNS) during transitions from grid power to island power and to provide ongoing frequency regulation to the New England electrical grid. In addition, a new Microgrid Control System (MCS) will integrate the BESS and a variety of existing on-site generation assets to implement a “fast load shed” (FLS) scheme. The control system includes new metering so the MCS can intelligently select the loads to shed in order to balance with available on-site generation supply. The combination of the MCS and BESS will considerably enhance the value of the Navy’s existing on-site generation assets in several ways.

- Existing generation assets include two 5.0 MW combustion turbines and two 1.5 MW emergency diesel generators. Yet this 13.0 MW of on-site generation capacity cannot currently prevent a facility wide blackout when grid power is unexpectedly lost. This is due to the Shipyard having an average peak load of 15MW to 18MW, which is greater than the available on-site generation, and the lack of an FLS scheme to shed non-essential loads.
- Batteries or flywheels can provide frequency regulation ancillary services to the ISO but are very expensive to install and operate. By combining a BESS with the on-site generation assets at the Shipyard, we expect to demonstrate that frequency regulation can be provided at a lower cost per capacity when compared to systems solely dedicated to providing ancillary services.

By deploying existing generation assets (which most military bases already have) in new ways through the systems proposed here, the government can generate revenues (from the sale of ancillary services to the ISO) that could not be previously exploited without the BESS. We believe our proposed system provides a more cost-effective way to capture revenues when compared to other battery or flywheel installations where the core function may be to solely provide an ancillary service.

This investment will significantly enhance the energy security of the Shipyard by maintaining power to all critical loads in the event of a loss of grid supply, avoiding otherwise lost production time and costs. Net energy costs will also be reduced due to revenues from the provision of Ancillary Services to the ISO-NE grid. If successful, the potential for broad implementation of this system across U.S. Government installations is promising. The demonstration will be split into two phases.

Phase I - MCS/FLS will integrate GE's Microgrid Control System (MCS) with Fast Load Shedding (FLS) to demonstrate Islanding and Energy Surety for the Shipyard. The MCS will exercise control of the BESS during "Microgrid" operation.

2014

- June - Nov – Design of the MCS architecture to be incorporated into the facility's infrastructure.
- Aug - Dec – Order components, build, and test system at GE facility.

2015

- Jan - Sept – Install infrastructure on-site
- Oct - Dec – Commissioning and Performance Verification Testing

2016

- Jan - Dec – Demonstration of MCS and BESS capability to Island.

Phase II - BESS participation in ISO-NE's Regulation Market

2014

- Jan - May – Design, manufacturing, and installation of the BESS components.
- June – Integration Testing, Commissioning
- Signed Interconnection Agreement (IA) and Activation in ISO-NE's Regulation Market.

Note: We were unsuccessful in getting an IA in place between the utility Central Maine Power and the Navy in time to participate in the ISO-NE Pilot program which expired at the commencement of the new active market rules implemented by ISO-NE effective April 2015 and approved by FERC. CMP and the Navy initially signed the agreement in August of 2014, however complications with the Navy's contracting process delayed full acceptance and modification to an existing contract with CMP and was not completed until May of 2015.

(Copies of the IA and Contract are found in Appendix F)

The new rules include a requirement of a 1MW minimum capacity, Ameresco is looking forward to future participation in this program by increasing BESS capacity at PNS to over 1MW during development of an Energy Savings Performance Contract (ESPC) presently in development)

2016

- Jan - Dec – Continue operation of BESS under Phase I

1.1 BACKGROUND

The Microgrid Control System (MCS) will significantly enhance the energy security of the Shipyard by maintaining power to designated critical loads in the event of a loss of grid supply as long as sufficient local generation is connected and live at the moment of the grid loss, to maintain the minimum of critical feeder loads. The MCS will control the BESS output during a “Loss of Utility” (LoU) event by interfacing with the Battery Energy Storage System (BESS) Site Controller to support additional critical loads while islanding until back-up generation comes online. In addition, the BESS will provide a new revenue stream from the provision of Ancillary Services to the ISO-NE grid, providing a means for payback towards the upfront costs. This technology is applicable to virtually all DOD sites, but especially those within utility service territories where Ancillary Services markets exist. To date, active Ancillary Services markets exist throughout most of the country including, but not limited to, NY ISO, PJM, Midwest ISO, ERCOT, and the California ISO. The information obtained from this demonstration will enable a clearer understanding of the rules, operating protocols, and potential magnitude of revenues from participation in Ancillary Services markets elsewhere throughout the country.

It is difficult to predict return on investment at this stage because Ancillary Services payments are still being defined, but we would anticipate paybacks of less than 15 to 20 years. Ameresco has modeled the potential revenue from providing frequency regulation services to ISO-NE. Our modeling used a simulation program provided by ISO-NE specifically to test various operating scenarios and system capacities. This model showed that revenues from our proposed 500 kW / 580 kWh BESS could be on the order of \$100,000 per year. If we expand our demonstration to utilize the on-site generation and increase the BESS capacity, we could increase the capacity of service offered to ISO-NE by at least a factor of ten to 5 MW of capacity and potentially capture revenues worth \$1.0 million per year.

GE has been engaged in an ESTCP demonstration at the Marine Corps Air Ground Combat Center Twenty-Nine Palms, California. The objective of that project is to demonstrate advanced microgrid control technologies capable of improving energy efficiency, expanding use of renewables, and increasing energy security. The MCS being demonstrated at Twenty-Nine Palms, focuses on resource optimization (i.e. optimal dispatch) and is not demonstrating fast load shedding for energy security nor does it demonstrate the commercial value of participation in the Ancillary Services electric markets. We feel the PNS demonstration will build upon the lessons of Twenty-Nine Palms and allow the government to tap new funding resources to accelerate the pace of implementation of essential microgrid electrical infrastructure upgrades at mission-critical military facilities. Even if Twenty-Nine Palms were to participate in the Ancillary Services market in the future, the California and New England ISO markets and operating rules are very different. There is value in defining the protocols and cost-effectiveness of participating in Ancillary Services in two very different markets.

The DoD community has recognized that the aging infrastructure of the commercial power grid has resulted in frequent power outages. Portsmouth Naval Shipyard experiences 2 to 3 such outages each year. These outages have resulted in the tripping of the Shipyard generating plants with the resultant disruptions in Shipyard Operations. The successful demonstration of Fast Load Shedding at Portsmouth Naval Shipyard represents existing technology that can be deployed at any DoD facility where there is on-site generation with or without renewable energy.

If these energy supplies are not sufficient to support the full load of the facility, then Fast Load Shedding will allow the most critical resources to stay online and support the mission critical loads and the maximum amount of non-critical loads.

1.2 OBJECTIVE OF THE DEMONSTRATION

The technical objective of this project was to demonstrate that the emerging technologies of MCS and BESS can be integrated with the local grid electric supplier both to increase energy surety of on-site generation and to provide economic value to the ISO. The economic value to the utility provides a revenue stream that can help pay for the upfront costs. This demonstration project shows how the government can pay for energy surety upgrades with private capital instead of, and or in combination with, appropriated government funds. This should dramatically accelerate the pace of implementation of this essential electrical infrastructure upgrade at mission-critical military facilities.

The Portsmouth Naval Shipyard is an ideal demonstration site which offered extensive existing on-site generation and electrical infrastructure and within an ISO Regulation Market. These characteristics exist at most military bases making the results of this demonstration applicable throughout the DOD. The technical approach to this demonstration were executed in the following phases.

Technical Development and Acceptance: In this phase, we developed the design and operational characteristics of the proposed systems which were reviewed and accepted by the Government.

Phase I – MCS/FLS

- Design the new MCS/FLS components to integrate with the Shipyard's existing 13.2kV electrical distribution system and finalize the selection of loads and circuit breakers to be automated.
(See Appendix E, a full set of As-built drawings can be provided upon request and clearance by NAVFAC-PWD ME)
- Design and complete the engineering and protection required to integrate the BESS into the MCS/FLS schema.
(See Appendix H)
- Create test plans for factory and site acceptance as well as performance verification.
(See Appendix B)

Phase II – BESS

- Design the new BESS components to integrate with the Shipyard's existing 480V Station Service Bus located at the Power Plant.
(See Appendix G)
- Produce Arc Flash, Load Flow, Short Circuit, and Heat Gain studies.
(See Appendix H)

Product Development and Factory Acceptance Testing: In this phase, the equipment manufacturers developed and tested the MCS/FLS and the BESS prior to shipping these systems to the site.

Installation, Start-up Testing, Commissioning, and Performance Verification Testing

Phase I – MCS/FLS

- The new equipment and systems were installed, and each subsystem commissioned in accordance with the Commissioning Plan protocols defined in detail in Appendix B.
- Conducted Performance Verification Testing. *(See Appendix B)*
- Monitoring, logging, and analysis of Live events over 12-month demonstration period. *(See Section 6.0)*

Phase II - BESS

- Defined the utility interconnection and communication protocols to qualify for participation in the Ancillary Services markets. *(See Appendix F)*
- Designed the control integration to the BESS to support the Ancillary Service requirements. *(See Appendix G)*
- Quantified the revenues available from ISO-NE for the level of Ancillary Services we can provide and define the operational requirements. *(See Section 7.0)*

Ancillary Services rules were promulgated by FERC in October 2011; ISO-NE's compliance filing and acceptance process took place between June 2013 and September 2014. Specific schedules for minimum operating capacity (1MW), capacity payments, performance payments, and performance requirements were finalized and implemented by ISO-NE in April 2015. ISO-NE operated a pilot program with a minimum operating capacity of 100kW through March 2015, however we were unsuccessful in getting an Interconnection Agreement in place in time to participate. An IA and modification to the contract between the Navy and CMP was eventually fully executed in May of 2015.

Ameresco is looking to the Energy Savings Performance Contract (ESPC) presently underway at PNS to potentially increase the BESS to over 1MW.

Operational Testing

Phase I – MCS/FLS

- Tested, evaluated, and documented the performance of the new equipment and systems over a 12 month period to capture performance under all Shipyard weather and operational conditions. We also studied the ability of the BESS to react to a loss of grid power.

- Energy and cost data was collected and the findings presented herein to encourage other sites to estimate potential benefits of a similar system.

Phase II – BESS

- Trial tested operation of the BESS on the ISO-NE Pilot Regulation signal
- Test, evaluate, and document the performance of the new equipment and systems over a 4 month period up to expiration of the ISO-NE Pilot program. The performance of the system will be evaluated based on the success of participation in the Ancillary Services market and the revenues generated.

Note: 4 month operation period was not able to be performed due to expiration of the ISO-NE Pilot program

1.3 REGULATORY DRIVERS

FERC Order 755

The order is significant to energy storage participating in Regulation markets such as ISO-NE, NY ISO, PJM, ERCOT, and CAISO, offering higher revenue potential. The new rules require the recognition of speed and accuracy, two attributes of energy storage systems such as the BESS in this demonstration, and provide additional value in the form of higher payments to these assets. To date, ISO-NE and PJM are the only markets to come into compliance with the new rules with CAISO, ERCOT, and MISO in development.

FERC 18 CFR Part 35

The Federal Energy Regulatory Commission is proposing to amend its regulations under the Federal Power Act (FPA) to remove barriers to the participation of electric storage resources and distributed energy resource aggregations in the capacity, energy, and ancillary service markets operated by regional transmission organizations (RTO) and independent system operators (ISO). Specifically, they propose to require each RTO and ISO to revise its tariff to (1) establish a participation model consisting of market rules that, recognizing the physical and operational characteristics of electric storage resources, accommodates their participation in the organized wholesale electric markets and (2) define distributed energy resource aggregators as a type of market participant that can participate in the organized wholesale electric markets under the participation model that best accommodates the physical and operational characteristics of its distributed energy resource aggregation.

DoD Directive 4180.01

It is DoD policy to enhance military capability, improve energy security, and mitigate costs in its use and management of energy.

To these ends, DoD will:

- a. Improve the energy performance of weapons systems, platforms, equipment, and products, and their modifications; installations, including both enduring and non-enduring locations; and military forces.

- b. Diversify and expand energy supplies and sources, including renewable energy sources and alternative fuels.
- c. Ensure that energy analyses are included in DoD requirements, acquisition, and planning, programming, budgeting, and execution (PPBE) processes. DoD 4180.01, April 16, 2014.
- d. Assess and manage energy-related risks to operations, training, and testing, to include assets, supporting infrastructure, equipment, supplies, platforms, and personnel.
- e. Develop and acquire technologies that meet DoD energy needs and manage risks; utilize appropriate resources and energy expertise in other governmental organizations and the private sector.
- f. Educate and train personnel in valuing energy as a mission essential resource.

2.0 TECHNOLOGY DESCRIPTION

2.1 TECHNOLOGY OVERVIEW

Ameresco installed and integrated the following new systems at Portsmouth Naval Shipyard:

- 500 kW / 580 kWh Battery Energy Storage System (BESS) to assure power quality on base during transitions from grid power to island power and to provide frequency regulation to the New England electric grid. System includes containerized battery, inverter, site controller, and communications hardware required to communicate with ISO-NE.
- Microgrid Control System (MCS) to implement a Fast Load Shed solution.
- The MCS Control system includes new metering in feeder controllers (nineteen breakers at the Power Plant, thirteen breakers at Substation 3 and the two Utility tie breakers (F1 & F12) at Franklin Substation). This metering data is used by the MCS to adaptively calculate the steady-state generation-load balance for changing power system conditions and select the prioritized loads to shed in order to maintain this balance following the detection of the loss of the Utility. This action will prevent the operating turbine generators from tripping on an overload. The feeder controllers provide relay trip control of twenty-nine (29) existing breakers (thirteen at the Power Plant, thirteen at Substation 3 and three at Franklin Substation).
- Dedicated fiber-optic communication system to allow monitoring of key components (e.g. switches, status of battery banks) at the central controller.
- GPS Time synchronization of the MCS components.

Phase I – MCS/FLS

Implemented a GE C90 and F35s to provide fast load shedding for a Loss of Utility event (PNS islanded) and BESS control during Microgrid Dispatch. The C90 and F35 devices are at commercial stage and have been used in similar systems at industrial facilities, and provide the flexibility and programmability to implement the key objectives of this demonstration. A high-level system architecture for the MCS is shown below in Figure 2-1. Please see Appendix E for full size document.

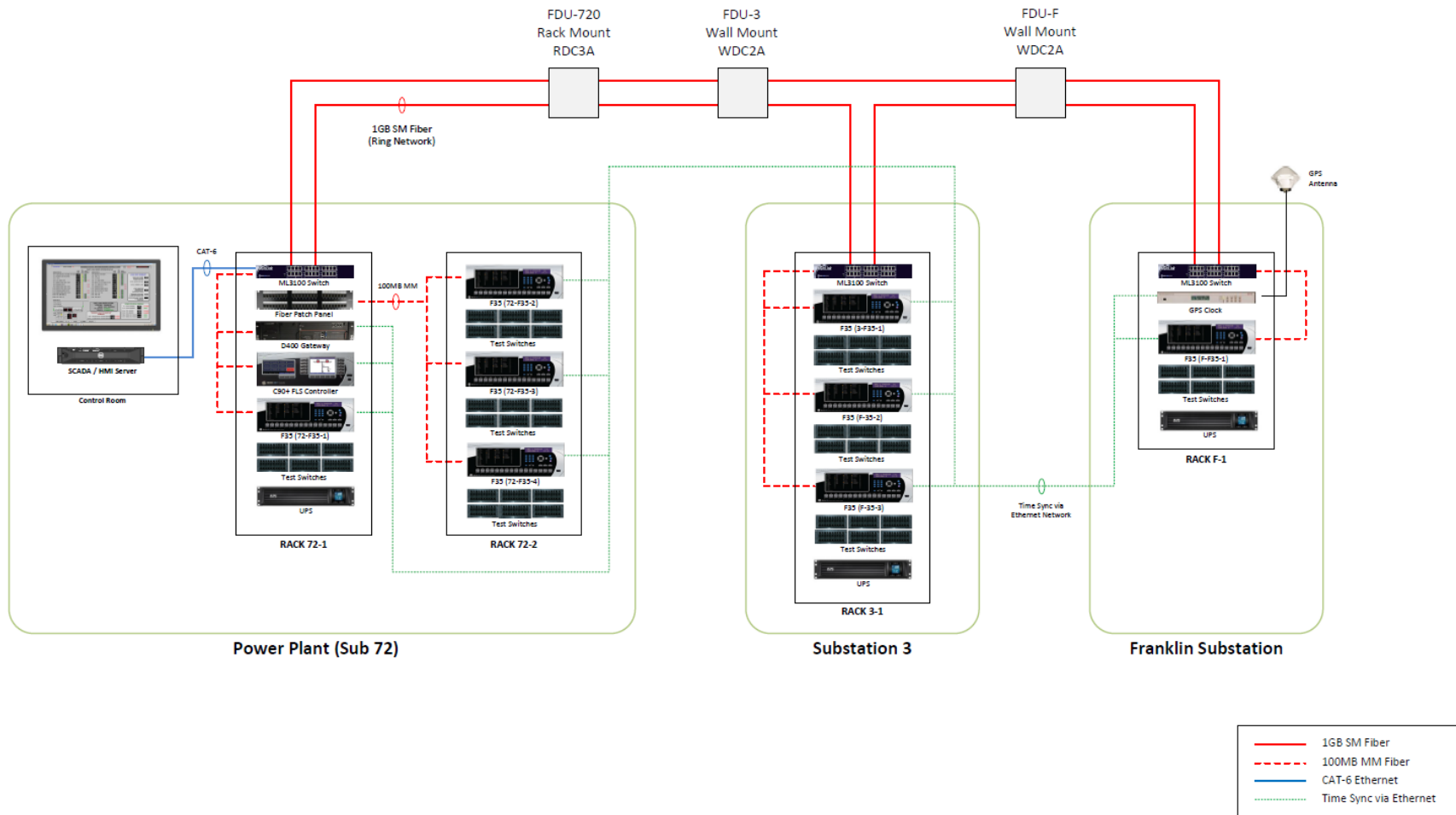


Figure 2-1 MCS System Architecture

The Demonstration MCS system is based on three repeatable building blocks that can be scaled to cover the entire Portsmouth Naval Shipyard or applied at other DOD facilities:

Major Components

Main Substation Controller Subsystem – The main substation controller subsystem is the master control required to coordinate fast load shedding, dispatch of BESS during islanding, and historical data archiving of events. The Main Substation Controller Subsystem consists of a D400 substation gateway for the communication interface with the BESS Site Controller for data acquisition for all conditions. The D400 also controls Microgrid dispatch of the BESS following loss of the utility and monitors the BESS performance under Microgrid dispatch. The Fast Load Shed (FLS) control is performed by the GE Multilin C90Plus Fast Load Shed Controller. A local Windows based server provides configuration services for the system's devices. The server is equipped with GE's Cimplicity SCADA software to provide the operator with visual displays of system conditions, alarms and control as well as data acquisition and storage.

The following system functions are completed by the Main Substation Controller subsystem:

- Operator monitoring and configuration of the FLS system
- System alarm and event management
- Real time monitoring of system power values
- Configuration of the priority of the loads to be shed
- Detection of the Loss of Utility (LoU) event and initiating the FLS based on maintaining a balance of power and load. The FLS determines the loads to be shed based upon a pre-configured priority established by PNS operations personnel
- Sequence of events recorder to record the operation of the system and store key data to analyze the operation of the system.
- Communication control between the C90Plus and F35 field controllers and the BESS Site Controller and Operator monitoring and control of the FLS.
- Automatic retrieval and storage of waveforms and event logs from all devices by HMI Server

Feeder Controllers – Three Feeder Control Cabinets are provided to interface the Main Substation Controllers to the 13.2kV circuit breakers located in the Power Plant, Substation #3, and Franklin Substation. The feeder controller is based on the GE Multilin F35 Feeder protection system and these units are responsible for:

- Interfacing the 13.2kV circuit breaker into the Demo Microgrid Control System
- Monitoring the open/close status of each breaker
- Monitoring the volts, amps, kW for each monitored 13.2kV critical circuit breaker and the incoming utility service.
- Communicating power and status back to the Main Substation Controller Subsystem and receiving the trip command from the C90Plus FLS Controller.
- Providing a Fast Load Shed trip signal to the 13.2kV circuit breakers

- Local storage of oscillography information and event recorder used to evaluate the operation of the system.

Note: It is the operator's responsibility to manually close all tripped breakers (normal operation, after event). In the Demonstration project, the system is not wired to remotely close a circuit breaker.

Ethernet Communications – A one Gigabit per second fiber optic Ethernet ring communications network has been installed with a GE ML3K managed Ethernet switch located at each site; Power Plant, Substation #3, and Franklin Substation. The ring design provides for high reliability and a secure communications architecture. The ML3K switches are equipped with a SMART RSTP feature that allows for recovery from faults in ring network architectures in less than 5 milliseconds per switch in the network – 10 times faster than generally available in standard Ethernet switches. The switch provides for 10/100 Megabits per second communications to each connected device.

The Fast Load Shedding scheme employs IEC 61850 GOOSE messaging to provide high speed communications between the GE C90Plus and the F35 Feeder Controllers. Modbus TCP/IP protocol is used to access data from the GE Devices and the DynaPower PCS by the D400 and the HMI-SCADA.

GPS Clock Time Synchronization – The system employs an Arbiter Systems 1084B GPS Satellite-Controlled Clock with the Network Time Protocol/Precision Time Protocol Server option. This allows the GPS Clock to act as time server over the Ethernet network using Network Time Protocol (NTP) and Precision Time Protocol (PTP). Typical accuracy for NTP is one millisecond on a LAN. The PTP Server, GE C90Plus and F35 Feeder Controllers support the IEEE 1588-2008 protocol assuring high accuracy time stamping all data and waveforms. PTP accuracy is better than 1 microsecond.

GE Microgrid Fast Load Shed Operation - The MCS continually monitors the PNS incoming utility breakers located in Franklin Substation for an islanded condition. An island condition is detected by a new F35 relay based upon tripping of the utility tie breakers by the existing utility under/over-voltage and under/over-frequency protective relays. In addition to these signals, overheat conditions from Turbine Generators may also be used to trigger load shed operation, but is not programmed for the demonstration. When an island condition is detected, appropriate IEC 61850 Generic Object Oriented Substation Events (GOOSE) messages are sent to the MCS. When the PNS power system is islanded from the local utility the MCS will complete the following actions as seen below in Table 2-1 (the priority of load shedding “candidates” is pre-configured):

Table 2-1 Operational Steps to Island

Step #	Step Description	Notes
1	Loss of utility; F1 and F12 at Franklin Substation trip and/or under-frequency detected at Power Plant (PP)	
2	Main substation controller sends trip messages to feeder controllers	Using IEC 61850 GOOSE messaging
3a	PP substation breakers 8, 9, 17 and 18 tripped by fast load shedding logic in main substation controller	Separates PP from Franklin Substation and Substation 2
3b	Feeder controllers trip Substation 3 breakers 7 & 13	Separates Substation 3 from Franklin Substation
3c	Power Plant feeder controllers trip appropriate load feeders to balance available generation	Depending on the output of the GTGs, station power requirements, and loads current being served
3d	Substation 3 feeder controllers trip appropriate load feeders to balance available generation	Same as 3c
3e	Franklin Substation feeder controller trips breakers 5, 9 and 10	Prevent back feeds through load centers
4	BESS Site Controller turns control of BESS over to D400 to charge or discharge real power to help balance available generation and support loads.	C90Plus initiates Mode change in BESS Site Controller.
5	Emergency generator controls bring further generating units on-line and BESS adjusts output.	Diesel Generators are automatically started and synchronized by DCS
6	NAVFAC personnel close breakers to pick-up additional critical loads.	

To complete steps 3c, 3d, and 3e above, the MCS has up to 30 pre-defined load shedding tiers with corresponding priorities. The total power shed will be calculated from the instantaneous power loads recorded by GOOSE messages from the UR F35 relays just before the islanding event. The C90Plus Controller will shed the loads according to priority, until the total load shed is equal or greater than the P_{Shed} , that is,

$$\sum_{i=1}^N Load_i \geq P_{Shed}$$

Equation 1 Calculation of Number of Load to Shed

$Load_i$ is the measured real kW value of each load in the Load Shed Tier Table.

P_{Shed} is the load shed order and is based on the present on-line generator resources.

The shed requests are sent from the C90Plus Controller to the F35s, installed in the load substations, in the form of GOOSE messages. Upon reception of the GOOSE messages, the F35s which are requested to shed load will trip their load breakers. The FLS only operates once and must be reset manually.

Phase II - BESS

- Installation of 500 kW / 580 kWh BESS of Lithium Ion chemistry.
- Worked through the control and communication protocols needed to satisfy the rigorous requirements of ISO-NE for participation in their ancillary services markets.

- Operated BESS in trial run on ISO-NE signal to confirm operability.

(The following tasks were not performed due to expiration of the ISO-NE Pilot program)

- Demonstrate the effectiveness of BESS in meeting ISO-NE's needs by documenting how often and to what extent the BESS resource is dispatched by ISO-NE.
- Determine the effective available capacity of a BESS given the variable requirements of the ISO that will alternately call for the charging or discharging of the system.
- Quantify the value of the ancillary services provided so that metrics on the cost-effectiveness of this resource can be established.

Major Components – See Figure 2-2

Battery – The battery is a Saft Intensium Max 20 consisting of 10 racks of Lithium Ion modules, each with a dedicated Battery Management System (BMS), and housed in a shipping container with integrated HVAC and Fire Suppression System. The container has a Central Control System which communicates via Modbus to the BESS Site Controller. System energy capacity 580kWh.

Inverter (PCS) – Manufactured by Dynapower, this unit is capable of both charge and discharge of the battery at 500kW of power with a response rate of up to 32,000kW/s (~500kW/16ms). The unit meets IEEE 1547 standards for interconnected distributed generation resources.

Site Controller – Manufactured by Dynapower, the Site Controller is the central controller for the BESS and its interface for the ISO-NE hardware and GE MCS.

RTU – The RTU is responsible for communicating Market Data and Reliability Data between the ISO NE Front end systems and the PCS Site Controller. The system will use Modbus over the ISO-NE dedicated Multiprotocol Label Switching (MPLS) network for communication back to ISO-NE.

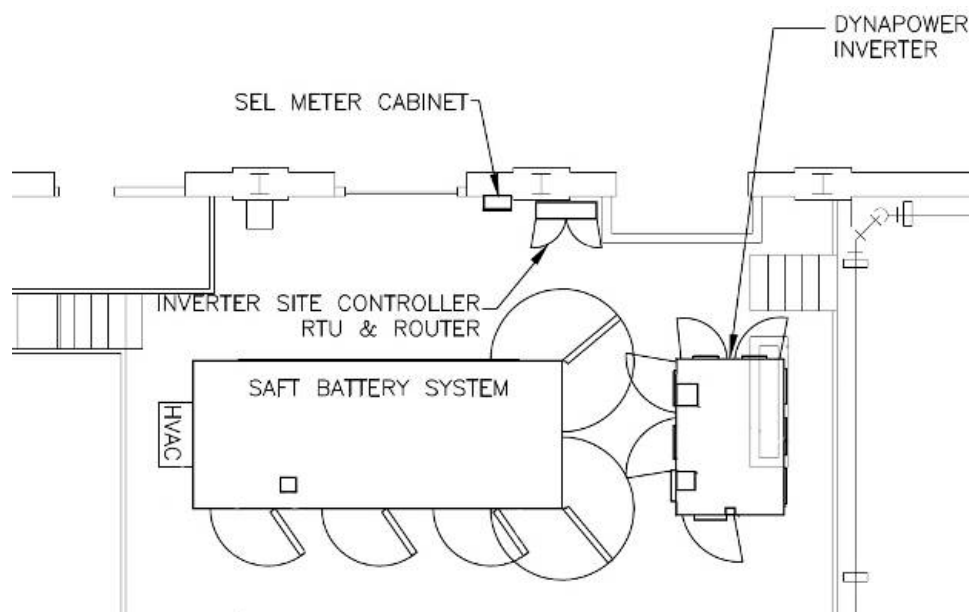
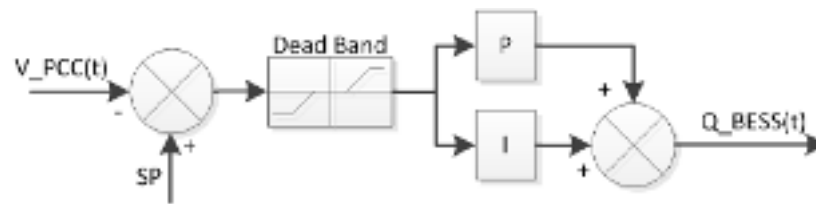


Figure 2-2 BESS Major Components

BESS Operating Modes

The Site Controller has three pre-defined operating modes programmed within the Site Controller. These modes can be selected through the HMI on the front of the BESS Site Controller cabinet. See drawing E-29 in Appendix G for Control Block Diagram explaining parameters for each mode of operation.

1. **Remote Dispatch** - The BESS Site Controller provides the ability to instruct the inverter to charge or discharge the battery when requested through the ISO-NE interface and thus provide regulation up or down translated as a change in demand at the facility's utility meter. The goal of this use case is to use the BESS for providing ancillary services to ISO-NE and participate in the non-generating resource regulation pilot program. New market rules to meet FERC Order 755 are in development, when the final rules are accepted the pilot will end and the BESS will be available to participate as an Alternative Technology Regulation Resource (ATRR) in the ISO-NE Regulation market.
2. **Automatic Voltage Regulation (AVR)** – In this use case the Site Controller will command the inverter to inject and absorb reactive power as a function of the voltage. The controller will be closed-loop and derive the set point from a predefined algorithm that comprises a dead-band and PI control up to the limit of the inverter and IEEE 1547 protection.



Simplified VAR Support Algorithm

$V_{PCC}(t)$ = Voltage the Point of Common Coupling
 SP = Nominal Voltage Set Point
 $Q_{BESS}(t)$ = Reactive power command to BESS

Figure 2-3 VAR Support Diagram

3. **Microgrid Dispatch** - The system will transition to Microgrid Dispatch mode from the Remote Dispatch mode in the event the main feed from the local utility is lost and the interconnection breaker opens initiating a transition to island mode. A 'grid down' relay located on GE's C90Plus indicates that the site is islanded. When in Microgrid dispatch mode, the BESS site controller will receive its active power (P), and control command and ramp rate setpoints from the GE D400 controller. The BESS will maintain constant output until the Diesel Generator(s) are synchronized on line and ready to carry the load that the BESS has been supporting. The D400 will then initiate a ramp down of the BESS and the BESS Site Controller will return to the previous operating Mode.

2.2 TECHNOLOGY DEVELOPMENT

Phase I – MCS/FLS

Preceding Development - GE's MCS has been under development for the past 10 years through various government partnerships with the US Department of Energy, DOD, and Canadian Government. Over the past three years, GE has transitioned a large part of the technology from GE's Global Research Center to GE's Digital Energy business as part of GE's technology transfer process. The core control platform has been transitioned to commercial purposes; however applications in integrating Battery Energy Storage Systems with MCS/FLS technology can benefit from further development as is demonstrated in this project.

Anticipated Development Benefits to DoD - The development and demonstration of algorithms and controls schemes that enable utility interaction with a DoD microgrid is an essential next step in achieving an economically viable energy surety microgrid, in that it allows for utility derived revenue streams that can pay for the premium of energy surety.

Site Specific Implementation - The primary goal of this Demonstration Project was to keep the Power Plant online during a Loss of Utility. Since the available generation at the Power Plant was greater than the loads served by the Power Plant, Feeder Controllers were also installed at Substation 3. The net result for this Demonstration was that the Power Plant and Substation 3 would operate as its own island, while Franklin Substation and Substation 2 and the loads they serve, would go dark. This separation was accomplished by opening the two loop feeders that tie the Power Plant to Franklin, the two loop feeders that tie the Power Plant to Substation 2 and the two loop feeders that tie Substation 3 to Franklin. This action results in the generation at the Power Plant being reserved to serve the remaining loads at the Power Plant and Substation 3.

See Appendix E for the basic architecture of the systems. A full set of As-Builts were developed to perform installation of the system at the Power Plant, Substation 3, and Franklin Station. The detailed As-Built drawing package is not included with this report due to reasons of facility security, however it can be provided on disk upon request and approval by NAVFAC PWD-ME.

Results Post Demonstration - The installation and commissioning of the MCS Fast Load Shed was completed in November of 2015. Ameresco and GE worked with NAVFAC PWD at PNS to gain approval to alter operation of the generation resources while conducting the Simulated Tests of the FLS so as to set up each of the desired scenarios. This eliminated the need to create an artificial means of testing the FLS using multiple test sets; real power measurements would be used in the FLS calculation. The initiation of the FLS is caused by the opening of the two utility tie breakers, F1 and F12, at Franklin Substation. Though generation was to be physically operated for the Simulated Tests it did not require the opening of F1 or F12 breakers or any of the load distribution breakers. The 'b' switch closing was simulated by applying a jumper to the Franklin Feeder Controller, F-F35-1. The first Simulated Testing revealed an issue with how the Infeeds for were being taken into account in the C90Plus settings. A thorough review of the FLS settings was conducted by GE and the GOOSE Messaging and C90Plus settings were updated to assure proper performance of the FLS. The Simulated Testing was repeated on December 3, 2015.

Two system Scenarios were tested:

- 1) Summer operation with one GTG (5MW) serving approximately 10 MW of PNS load.
- 2) Winter Operation with two GTGs (~10MW) serving the same load. These tests successfully demonstrated that the FLS could perform as designed and that the Power Plant should be able to stay on line.

It was agreed by all parties, including NAVFAC and the base Command, that the only true means of verifying the MCS/FLS performance was to conduct Live Testing. The Live Tests were conducted on December 8, 2015. The proper performance of the MCS/FLS was successfully demonstrated. The Power Plant remained online and the <50 ms speed of the FLS operation was far better than the original expectation of 140ms. In fact, the overall trip time was ~80ms when one includes a 32ms auxiliary relay delay at Franklin. This auxiliary relay was needed to replicate the action of the F1 breaker 'b' contacts as there were no spares available. Table 1 in Section 3.0 provides a Summary of the Live Test Results and how the Performance Objectives for the MCS/FLS were met or exceeded. The detailed presentation of the PVT Simulated Tests and PVT Live Tests are presented in Section 6.0

Transfer of Technology - In terms of follow-on implementation, the design and demonstration of the microgrid system and BESS was developed such that it can be deployed to other installations in a replicable, modular, and scalable fashion. The features that have been developed and demonstrated will have application with other utilities and in a manner that is familiar to the government's standards of operation. The PNS personnel are very satisfied with the performance of the MCS and are planning to expand the technology to encompass Substation 2 and Franklin Substation under an Energy Savings Performance Contract presently in development. This expansion will simplify the FLS settings as the loops that tie the substations will no longer need to be monitored and tripped thus reducing the duty on six 13.2kV circuit breakers. And by defining the financial value and payback associated with providing Ancillary Services, this demonstration will accelerate the transition of this innovative technology to more widespread use.

With the experience gained out of this demonstration a white paper has been written and submitted for publishing with IEEE titled "Experience with Fast Load Shedding using IEC 61850 GOOSE". See Appendix L for a copy of this paper.

Phase II - BESS

Preceding Development

For this demonstration, we selected Saft, a manufacturer who has been developing battery technology for nearly a century. Saft offers several grid-tied solutions ranging from 100kW to multiple megawatts in electrical capacity. Their deployment experience is broad having manufacturing facilities located in both Europe and the United States with a new facility built in Jacksonville, Florida where the unit for this demonstration was built.

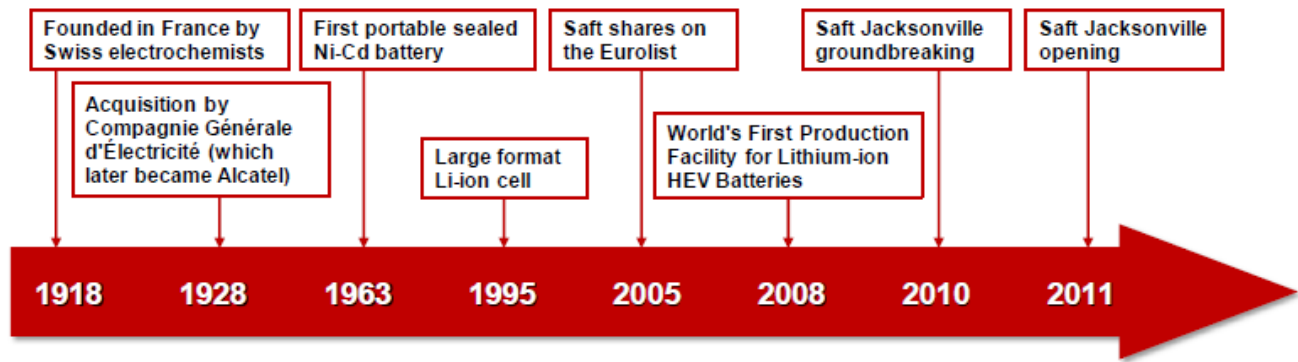


Figure 2-4 Saft Company Timeline

Deploying energy storage systems on the electrical grid has also increased over the past decade and it is in the interest of this demonstration to extend that experience to the Department of Defense. The following graph shows the megawatts of electrical capacity installed in the U.S. dating back to 2012 with an upward projection out to 2019. Though integration of energy storage with the electrical grid is still a relatively nascent market, we find energy storage is maturing at a rapid pace with a high demand and broad support by local, state, and federal sectors.

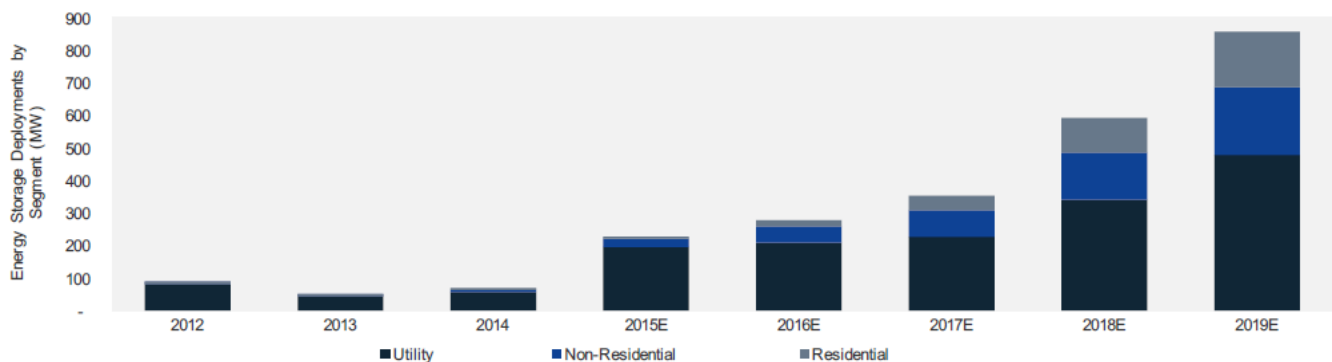


Figure 2-5 Installed U.S. Capacity Energy Storage Systems

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Anticipated Development Benefits to DoD and Site Specific Implementation

The DoD has a clear initiative to always be improving reliability and security of the utilities which directly support the daily activities of the mission. A reliable supply of electricity to the facility is possibly the most critical utility required to maintain operability of a site in both normal operating conditions and times of emergency. Integrating energy storage into this demonstration will prove two primary benefits.

Emergency Backup Capacity (Phase I) – The BESS will demonstrate its ability to serve as a generator for emergency backup which can transition from stand-by to dispatch in a matter of milliseconds. Two modes of operation were tested during this demonstration.

The first being for the BESS to serve as a “buffer” where the 500kW of capacity is dispatched in sequence with the FLS but *not* accounted for in the load shed priority calculation to support additional critical loads during an islanding event. In this mode the unit provides some additional capacity to absorb any near-term change in the load conditions between the FLS making its calculation and tripping breakers and until the Gas Turbine Generators and/or Emergency Diesel Generators stabilize from the islanding event.

In the second mode of operation the BESS is demonstrated to operate as a “bridge” until additional emergency generation served by the diesels comes online. In this mode, the FLS calculation includes the capacity of the BESS to support additional critical loads. Where the BESS can operate in milliseconds a traditional emergency diesel generator in stand-by will take around 60 second to start and synchronize to the grid.

Ancillary Services (Phase II) - While the BESS is primarily integrated with the interest of supporting the transition to islanding during an emergency event. We can also demonstrate the benefits of the BESS being utilized during normal operating conditions by participating in ancillary services available in the electricity market. By participating in these markets we can generate revenue which can go towards reducing energy bills for the facility and paying for the upfront and operating costs of the BESS.

Portsmouth Naval Shipyard is served by Central Maine Power as the owner of the transmission and distribution system and ISO New England as the regional system operator which manages the greater electrical grid as well as administers electricity markets. ISO-NE developed a pilot program to demonstrate the utilization of fast responding resources, such as batteries, to provide frequency regulation to the greater grid.

Results Post Demonstration

Emergency Backup Capacity (Phase I) – Operation of the BESS during a loss of utility in sequence with the FLS was demonstrated in Phase I. A summary of performance was addressed in the previous section and can be found in “Table 1. Summary of Live Test Results”

Ancillary Services (Phase II) – In order to participate in the ISO-NE Pilot program a line of communication had to be set up between the BESS located at Portsmouth Naval Shipyard and ISO-NE’s central control center in Holyoke, MA. The telemetry was installed and programmed per ISO-NE’s Operating Procedures manual “OP 18 – Appendix F”, which can be found on their website.

The following diagram in Figure 2-6 is taken from that manual which depicts the communications architecture tested. Sheets E-03 and E-04 in Appendix G show the communications as installed and tested for this demonstration. Testing of the telemetry and dispatch of the BESS took place over a one hour period where ISO-NE supported via phone and operation of the BESS following the ISO-NE Automatic Generator Control (AGC) signal was performed. The system proved to operate as designed and followed the signal. Due to the lack of an Interconnection Agreement at that time, the system was not approved to participate in the Pilot. ISO-NE did agree to allow the system to operate temporarily to prove connection of the system was a success and is able to technically follow the AGC signal.

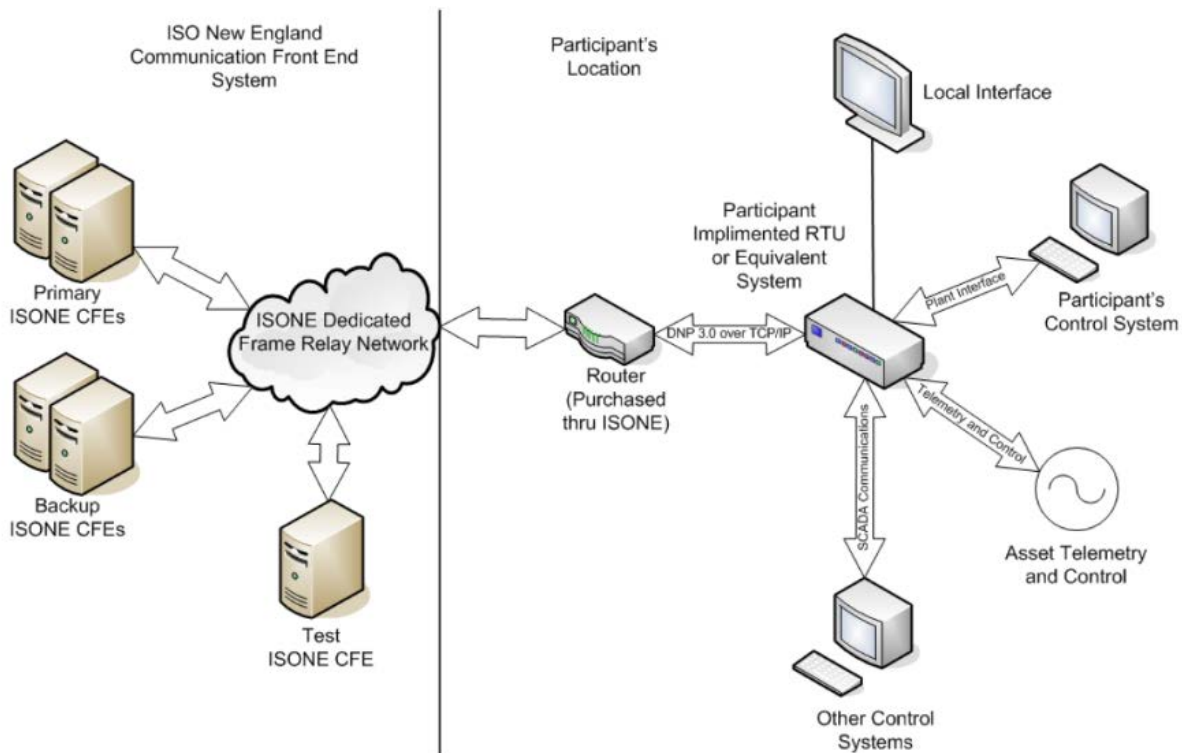


Figure 2-6 ISO-NE Communications Architecture

2.3 ADVANTAGES AND LIMITATIONS OF THE TECHNOLOGY

Phase I – MCS/FLS

The technology applied at Portsmouth is flexible in its application and the F35 feeder controllers provide for a very cost effective retrofit solution. The C90Plus controller is unique in that it uses hardware that has been designed to be used in utility and industrial environments and is the first controller of its' type to use IEC61850 GOOSE messaging to provide high speed, secure communications. The solution is expandable and using C90Plus Aggregators can load shed up to 2,500 loads.

The F35 controller also offers feeder protection capabilities that can replace ageing electromechanical and solid state relays that are reaching their end of life. This capability was not implemented, but is under active consideration by PNS. This can further reduce the cost of implementing the MCS Fast Load Shed while providing the facility with additional insight into power system disturbances and faults through the event logging and waveform capture capabilities inherent in these devices.

Clearly, this technology can provide the U.S. Navy, as well as other DoD facilities, with greater energy surety for their shore operations.

Over the twelve month demonstration period PNS experienced three live events where electrical service from the local utility (Central Maine Power) failed. In two out of three of these live events the Gas Turbine Generators tripped off-line resulting in a facility-wide blackout.

During Performance Verification Testing (PVT) it was demonstrated that the system functions as designed (See Section 6), resulting in a successful operation of the FLS and transition of the Gas Turbine Generator (GTG) units to island mode. However during a live scenario, it has been determined that the utility tie-breaker protection relays are not sufficiently fast enough in detecting the fault and in turn opening in time to protect the plant. Working with the local NAVFAC PWD engineers it has been decided that there is need to install a Remote Transfer Trip between the utility tie-breaker at PNS back to the public utility's recloser located at their 34.5kV substation approximately 3 miles away. See Section 8.0 for further detail.

Phase II - BESS

The storage of energy has been in development and in implementation for well over a century. One of the fastest growing and advancing technologies is solid based chemistry batteries. There are numerous companies within this sector who have decades of proven manufacturing experience and success in producing standardized cells. Within the past 20 years the battery industry has made great strides in increasing both energy density and life cycles while also providing higher rates of charge/discharge, predominately made possible by the advancement of lithium ion chemistry.

The following chart depicts the many forms of energy storage available on the market today showing the operating characteristics and preferred applications for each.

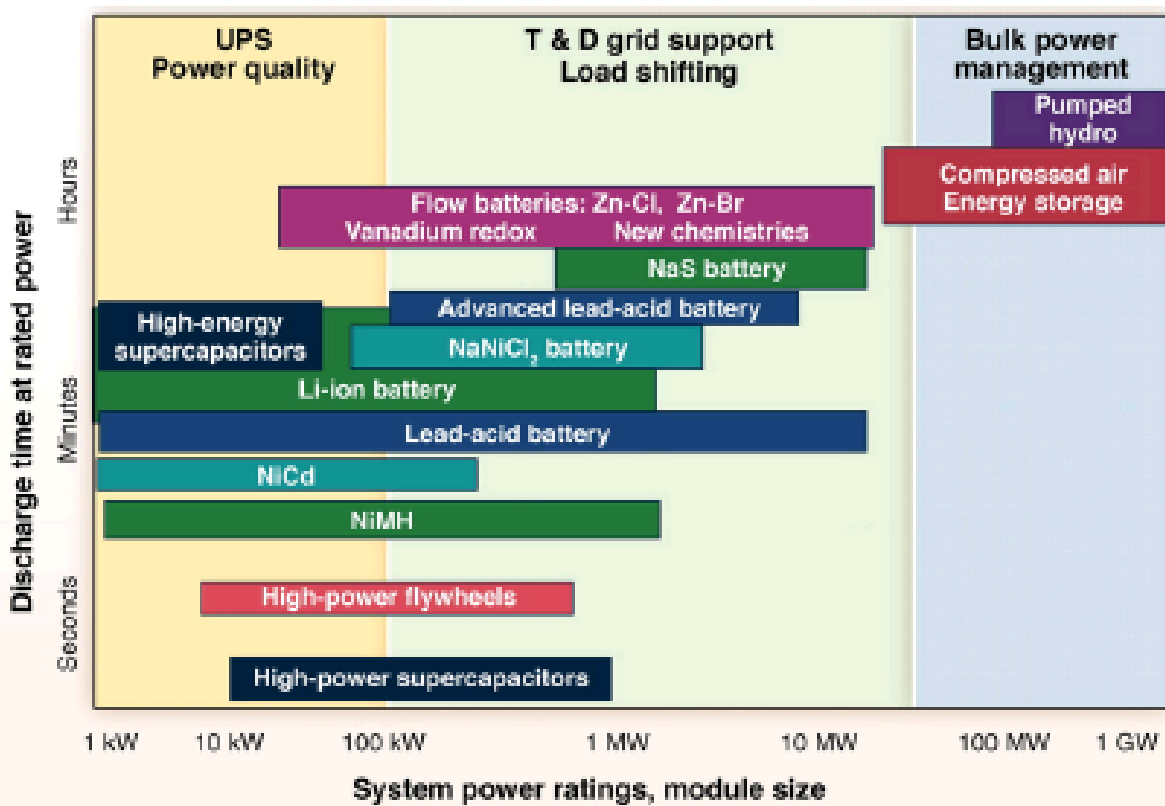


Figure 2-7 Energy Storage Technology Range of Application

We selected lithium ion for this demonstration keeping in mind the application at hand which is to provide interim emergency back-up power during an islanding event (Phase I) and participate in the ancillary services market, specifically the ISO-NE Pilot program running on frequency regulation (Phase II), both of which require dispatch in sub-hour time frames.

Regarding alternative technologies, we researched and considered Advanced lead-acid and NaS chemistries, both of which may have been capable of meeting the operating profiles we desired for our application and coming in within budget. However, both companies we sourced pricing from during the time of development subsequently experienced either critical cell level failures or changes in design which ultimately resulted in discontinuation of those products or even bankruptcy of the manufacturer. Other manufacturers of these chemistries exist and are worth watching for future development however we have seen steady and dramatic decreases in the cost of lithium ion based systems specifically just over the three years since the kick-off of this demonstration and expect this trend to continue. Flow batteries may also be another promising chemistry to consider in future projects, with this technology maturing and coming down in cost. Though, it must be noted that the optimum operating profile for this chemistry is multiples of hours at a low rate of discharge relative to its storage capacity, which does not meet the needs of the applications in this demonstration.

3.0 PERFORMANCE OBJECTIVES

Phase I - MCS/FLS System

The primary metric for a successful deployment of the Fast Load Shed (FLS) system is based upon keeping the Power Plant online through transition to Island mode following a Loss-of-Utility (LoU) event. A secondary metric of success is the ability of the Islanded system to maintain electric service to mission critical loads at the Shipyard. The HMI affords the Operator the ability to prioritize the tripping/non-tripping of the Shipyard loads at the Power Plant and Substation 3. This gives the Operator the flexibility to adjust the FLS to match the day-to-day Shipyard operations schedule. The demonstration will monitor and measure Proficiency of the MCS to Match Load to Capacity (MW), Success of MCS to Fast Load Shed (FLS) (measured in speed of response in milliseconds), and BESS Participation in Transition to Island Mode (Enabled/not enabled in FLS calculation – measured load maintained/shed).

The system's effectiveness in eliminating Power Plant outages will determine how much downtime was avoided in a given year from loss of public utility outages. Additional savings related to Annual Avoided Cost in lost productivity (\$) will be estimated. This measurement can be used to justify the upfront costs to implement the Fast Load Shed system at a given facility, based on the value of the services that facility provides. A facility's operational requirements (energy surety of critical loads vs. use of reserve margin to serve non-critical loads) will ultimately determine this value. For example, the FLS allows for the inclusion of a reserve margin for a generator that is on-line. If this margin is set to zero, then more load will be shed to maintain energy surety. This setting is user selectable. A consideration in establishing this margin is the response time of the generators to pick-up additional steady state load. This requires stability studies to be performed to establish whether the generator control response is fast enough to support the steady state load requirements of the island.

**Table 3-1 Performance Objectives
Phase I – MCS/FLS**

Performance Objective	Metric	Data Requirements	Success Criteria
Quantitative Performance Objectives			
Energy Security	Power Plant Non-Trip for Loss of Utility event	Document Power Plant Trip/Non-Trip for Loss of Utility	The Shipyard successfully islanded without Power Plant trip for each Loss of Utility event tested during the two (2) PVT Simulated Tests and the two (2) Live Tests.
Proficiency of MCS to Maintain Generation – Load Balance for Loss of Utility	Power Values (MW)	Pre-/Post- Loss of Utility Power measurements for all monitored breakers, breakers tripped, generating units on-line, and FLS settings established by Shipyard	The MCS trips sufficient load to maintain steady state Generation – Load Balance for Loss of Utility. The summer configuration (1 GTG) was tested and the FLS correctly tripped a total of 1,161kW of load at the Power Plant and Substation 3. See C90Plus Event Log and HMI Screen Shot. The winter configuration (2 GTGs online) was tested and no additional load was required to be tripped at the Power Plant or Substation 3 as the online generation was sufficient to support the connected load. See C90Plus Event Log and HMI Screen Shot.
Demonstration of Fast Load Shedding	Time (ms)	Document time to trip from detection of loss of Utility	Trip command < 3.0ms, overall trip time <2.1 + breaker trip time <50ms. (Power Plant and Substation 3 were islanded and all loop and load breakers were tripped in less than 50ms. See the Wavforms for each Test. The total trip time, including the delay caused by an auxiliary relay at Franklin, was less than 80ms.
Annual Avoided Cost of Lost Production	Number of events per year, value of lost Shipyard production per event	History of lost production costs for Loss of Utility events	The simple payback of the system is greater than or equal to the useful life of the FLS system.
BESS Participation in Transition to Island Mode	Power (MW) and time (ms) of response, and additional load maintained	MCS control actions, BESS status, response time, BESS kW	The MCS successfully dispatched the BESS following Loss of Utility during the Simulated Tests, acting as a “Buffer”. The BESS was bypassed during the Live Tests. Follow-up testing was performed to demonstrate the BESS operating as a “Bridge”, though the BESS dispatched the FLS program failed to take the additional capacity of the BESS into consideration with the load shed priority calculations. GE identified the error in calculation and formulated a corrective action to alter the programming to resolve the issue. Due to time constraints and logistical challenges of receiving approval to perform follow-up testing the re-programming has not been performed to date but is planned to be implemented during the next phase of build out in the upcoming ESPC.

**Table 3-1 Performance Objectives
Phase I – MCS/FLS (Continued)**

Performance Objective	Metric	Data Requirements	Success Criteria
Qualitative Performance Objectives			
Ease of Use	Operator Success in Learning the System	Interview PNS Personnel	NAVFAC personnel have gone through training and were responsible for operation/monitoring of the system over the 12 month demonstration period.
Operational value of MCS/FLS	Degree of Satisfaction	Interview PNS Personnel	Overall the operators have come to value the capabilities of the MCS/FLS; in particular, the additional generator/load data provided by the HMI in the control room. Though PVT proved operability of the FLS, live events over the demonstration period proved that additional components on the utility tie-breakers are needed to successfully island consistently. Only one out of four live events resulted in a successful transition to island mode.
Transferability of MCS-FLS application to other DoD sites	Review of Solicitations and Projects Underway	Industry Awards and Projects out for Solicitation	Ameresco is presently in development of three Energy Savings Performance Contracts which include MCS/FLS and BESS technology, including another phase at PNS. Increasingly, ESPC solicitations are coming out with microgrid technologies specified.

- Name and Definition: **Energy Security**, is a measurement of whether the Gas Turbine Generator(s) (GTGs) remain on-line and continues to supply power to the Power Plant following a Utility Trip.
- Purpose: Historically, the Shipyard experiences 1 to 3 unplanned utility trips per year that result in the GTG(s) tripping due to a power imbalance, e.g. load is greater than available GTG MW output. The result is Shipyard Operations has to restart the GTG(s) and then manually add load.
- Metric: The Non-trip/Trip of GTG(s) for a Loss of Utility event
- Data: Operator log of result: Non-trip or Trip.
- Analytical Methodology: GPS time-synchronized data, events and waveforms will be collected from the D400, PCS, and F35 relays and analyzed to provide a complete understanding of the Loss-of-Utility event.
- Success Criteria: The Shipyard is successfully islanded without the GTG(s) tripping.
- Name and Definition: **Proficiency of MCS to Maintain Generation – Load Balance** for Loss of Utility is determined by comparing the amount of actual load shed (breakers tripped) by the FLS with a calculation of the pre-event load values.

- Purpose: The proficiency of the FLS can be evaluated by verifying that the minimum amount of lower priority load has been shed to maintain generation and load balance.
- Metric: Measurement (MW) of generation, loads and Utility power values pre-event and post event.
- Data: Power measurements for all monitored breakers and log of Breakers Tripped for Pre-/Post- Loss of Utility event. Pre-event and post-event details for number of generating units on-line and power values.
- Analytical Methodology: The power values for key breakers at the Power Plant and Substation 3 are being monitored continuously by the F35 feeder controllers. Not all breakers are being monitored. The initial goal of this Demonstration was to maintain the operation of the Power Plant following the loss of the Utility. During the evaluation of the Shipyard load data it was recognized that the Power Plant had sufficient generation to allow mission critical loads at Substation 3 to be maintained by tripping of non-essential loads at Substations 3 and the Power Plant.
- For purposes of this Demonstration, the Shipyard can be considered to be composed of two systems: The Primary System consists of the Power Plant and Substation 3. The Power Plant has two ties to Substation 3 and the power flow to Substation 3 from the Power Plant is monitored. The Secondary System consists of Substation 2 and Franklin Substation. Franklin has two ties to the Utility. The power flow from the Utility to the Shipyard is measured and recorded to document the amount of Utility power flow that is lost. The Power Plant has two ties to Franklin and two ties to Substation 2 and Substation 3 has two ties to Franklin. The power flow across these ties is measured and the net sum of these ties represents additional power available to the Primary System for balancing. The data recording system will allow for detailed analysis of the LoU event while taking into account all key power flows.
- Success Criteria: Analysis of data shows that the minimum amount of load has been tripped based upon the priority settings in the C90Plus and that the generating units continue to supply power to the remaining loads.
- Name and Definition: **Demonstration of Fast Load Shedding** is effected by initiation of tripping of selected breakers within 20 ms of detection of a LoU event at Franklin Substation. Overall trip time for selected breakers is less than 20 ms plus normal breaker trip time (3 to 5 cycles).
- Purpose: The FLS of the selected breakers will allow the Shipyard generation to maintain stability and the remaining load will match the output of the generation with a margin as specified by NAVFAC.
- Metric: The GPS time synchronization will allow for millisecond (ms) time calculations of operations.
- Data: Time synchronization of the F35s allows for accurate time (1ms) calculations.
- Analytical Methodology: The FLS and Shipyard operating times will be determined from the time stamped event logs and waveforms captured by the F35 Feeder Controllers.

- Success Criteria: Fast load shedding is initiated within 15ms to 20ms by the C90Plus upon detection of a LoU event. The trip time of the selected breakers will be 3 to 5 cycles (48ms to 80ms) depending upon the breaker specifications. The overall trip time is less than 4 to 6 cycles.
- Name and Definition: **Annual Avoided Cost of Lost Production** is a measure of the effectiveness of the FLS to prevent tripping of the GTG(s) and complete loss of power to much or all of the production facilities. The avoidance of this lost production by the non-tripping of the GTG(s) can be quantified in real dollars.
- Purpose: This avoided cost (savings) can contribute to the upfront cost of implementation and operation of the Fast Load Shed system.
- Metric: Historical data on number of events per year, length of each event, size of loads (MW) being served, and cost of lost production per hour based on loads saved.
- Data: Events experienced over the demonstration period.
- Analytical Methodology: The PI will research the operational records for the Shipyard to establish the number of Loss of Utility events. The PI will establish the length of each outage. The PI will work with Shipyard Operations to establish an estimated hourly cost. And the size of the loads (MW) lost versus saved. This data will allow for the calculation of a yearly cost, or Annual Avoided Cost, for Loss of Utility Events. The Total Cost of the FLS can then be divided by the Annual Avoided Cost to establish a simple payback in years.
- Success Criteria: The upfront cost of the system divided by the Annual Avoided Cost of Lost Production is greater than or equal to the useful life of the FLS system.
- Name and Definition: **BESS Participation in Transition to Island Mode** can provide up to 1 MW of additional power to serve the Shipyard loads. The D400 will monitor the BESS site controller and provide current BESS power values (-500kW to +500kW) to the C90Plus for inclusion in the power balance calculation. Upon detection of the LoU event, the D400 will initiate the Microgrid control of the BESS to go to full kW output. This output will be maintained until the Diesel Generators are available to pick up load, acting as a “Bridge” until the back-up generation comes online. At that time, the BESS site controller will revert to normal operation mode.
- Purpose: To provide additional power to the Shipyard power system to allow the maximum MW of load to be supported during the critical transition to Island Mode.
- Metric: BESS Power (MW) flow, response time (ms), support time (seconds) and additional load maintained.
- Data: The D400 is controlling and monitoring the BESS site controller. The D400 will time stamp the initiating signal and the recorded BESS data. The SEL meter will provide additional data regarding the power flow and response of the BESS.
- Analytical Methodology: The time synchronization of the data in the D400 and SEL meter will allow for detailed analysis of the performance of the D400 controller and the BESS response during the transition to island mode. The ramp rate and power output can be verified. The power output of the BESS during this period will be translated into an

Avoided Cost of Lost Production as established in the previous Quantitative Performance Objective. This cost will be capitalized and added to Revenue Generated benefit calculated for participation in the ISO-NE Regulation market.

- Success Criteria: The MCS demonstrates that it is able to successfully initiate fast control of the BESS following and LoU event. Further, the BESS demonstrates a significant contribution to the support of the Shipyard loads thus reducing the time to restore full operations to the Shipyard.
- Name and Definition: **Ease of Use** will be demonstrated by the Operators ease in learning the system, the understanding of the HMI screens, the regular updates of the Load Shed Priority and use of the HMI system in aiding the Operator in the manual restoration of loads that were shed by the MCS/FLS.
- Purpose: The operation of MCS/FLS will predominately run via automation. However, the Operator plays a key role in interfacing with the MCS/FLS in establishing the Priority of loads to be shed based upon daily operational needs of the Shipyard. The HMI displays of tripped breakers as well as power flows on the monitored feeders will supplement the existing SCADA system by providing the Operator with additional real-time information.
- Metric: The degree of success in which the Switchboard Operator shifts learn to operate the system and their understanding and use of the HMI displays during a LoU event.
- Data: Measure the degree of knowledge through interview.
- Analytical Methodology: Interview.
- Success Criteria: The Operators understand and agree that the system is easy to monitor and operate.
- Name and Definition: **Operational value of MCS/FLS** will be determined by the successful demonstration of the MCS/FLS and the experience of NAVFAC management, Operators, and Technicians.
- Purpose: To evaluate the direct experience of NAVFAC management, Operators, and Technicians with the use of the MCS/FLS and the Operational benefits of having kept the Power Plant operational following a LoU event and the ability to maintain power to mission critical loads will be a positive for NAVFAC customers.
- Metric: The degree of satisfaction with the implementation and performance of the MCS/FLS.
- Data: Measure the degree of satisfaction with the MCS/FLS through interview.
- Analytical Methodology: Interview.
- Success Criteria: The NAVFAC management, Operators, and Technicians Switchboard Operator are satisfied with the implementation and operation of the MCS/FLS.
- Name and Definition: **Transferability of MCS/FLS to other DoD sites** will convey the likelihood that the demonstration can be repeated with success at other installations.

- Purpose: A common goal of all ESTCP demonstrations is to determine the breadth of applicability for a technology across a multitude of federal installations. Based on technical, operational, and economic characteristics we will attempt to estimate the scale of Loss of Utility issues within DoD.
- Metric: Review of Solicitations and Projects Underway.
- Data: Industry Awards and Projects out for Solicitation.
- Analytical Methodology: Industry knowledge.
- Success Criteria: Presence of new projects either awarded or out for solicitation.

Phase II - BESS

The objective of this phase is to demonstrate the capability and benefits of a BESS participating in Ancillary Services. The technical requirements include automated control and communication of the BESS with an ISO. The benefit in turn is the generation of revenue through payments from the ISO which can in turn create an annuity to be applied in payback of the investment. This positive cash flow may provide the opportunity for performance contracting such as Energy Savings Performance Contracts (ESPCs) and/or Power Purchase Agreements (PPAs). See Section 7.0 for further details.

While the BESS is set up to participate during this phase in ancillary services, sufficient storage capacity (20% State of Charge) is reserved for operation during Phase I. During operation in ancillary services, the BESS may be in either a charge or discharge command, the FLS takes the present power +/- kW of the battery Power Conversation System (PCS) into consideration when determining the amount load necessary to be shed. For example if the BESS is charging at 500kW, acting as a load, the FLS sees this as a load which can be controlled and further turned into an additional 500kW of capacity to support additional “real” loads, resulting in a net sum of 1MW of additional loads which can be saved.

Two metrics which determine the amount of revenue which will be generated in the ISO-NE Regulation Market are Automatic Response Rate (MW/min) of the BESS and its Hourly Performance (%). Multiplying these measurements by the capacity (MW) bid into the market will result in a Revenue Generated (\$).

These metrics will be useful in determining the feasibility of technology transfer at other bases within the ISO-NE region, as well as the greater ISO/ RTO regions throughout the US with similar markets; such as PJM, NYISO, MISO, ERCOT, and CAISO.

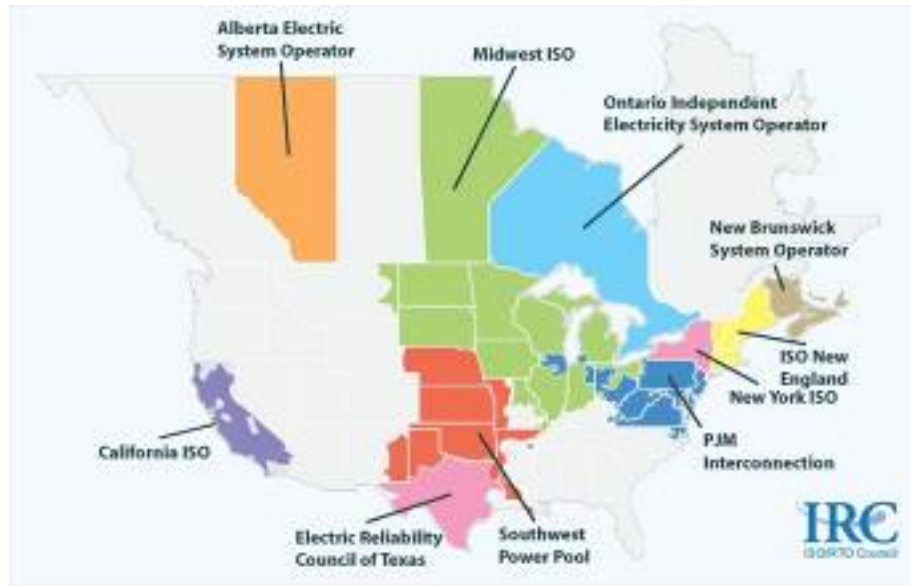


Figure 3-1 Deregulated Electricity Markets

Table 3-2 Performance Objectives Phase II - BESS

Performance Objective	Metric	Data Requirements	Success Criteria
Quantitative Performance Objectives			
BESS Automatic Response Rate	MW/min	Logging w/ D400 and/or Power Quality Meter MeMeter	100 MW/min
BESS Hourly Performance	%	ISO-NE Reports	95%
Revenue Generated from BESS in Regulation	\$	ISO-NE Reports	Aprox. \$8,000/mo or \$100,000/yr
Qualitative Performance Objectives			
Ease of Operational Use of BESS with ISO-NE	Operator Success in Learning the System	Switch Board Operator Feedback	Ability for operator with limited training to operate the system.
Transferability of BESS to Operate at other sites	Market Outlook	ISO/RTO, State, and/or Utility Policies	Regions encouraging participation of Energy Storage on grid.

- Name and Definition: **BESS Automatic Response Rate**, is a measurement of how quickly the Inverter can change state in response to instruction from the ISO. Example: Transition from -500kW to +500kW in how many seconds.
- Purpose: This measurement is used by the ISO to determine the value of the Regulation service provided by the ATRR. The higher the MW/min value, the closer the unit can follow the AGC signal, resulting in a faster response to the ISO's request in correcting frequency on the electric grid. This metric will influence how much revenue the BESS generates.

- Metric: The units are MW/min. ISO-NE can benefit from speeds of up to 100MW/min. The Inverter specified for this project is capable of 32MW/sec, which is -500kW to 500kW in one cycle (500kW/16ms). This equates to 1,920MW/min.
- Data: An SEL-735 power quality meter/logger will be used to measure kW output of the Inverter over time as it follows the AGC signal controlled by the ISO. A GE D400 will be used to log AGC signal commands via the Modbus communication; the D400 will be programmed to capture all relevant Modbus system control points including the kW command coming in from ISO-NE. Independently, ISO-NE's MIS reporting will provide monthly system performance data.
- Analytical Methodology: A curve depicting MW/min vs Time (hour) will be used to display the response rate as the Inverter follows the AGC signal. Multiple curves may be produced to show select hours that depict unique operating characteristics of the system.
- Success Criteria: The system is expected to provide a Response Rate in excess of 100MW/min at all times while following the ISO-NE AGC signal.
- Name and Definition: **BESS Hourly Performance**, is determined by the assets % participation within a given hour the system is providing service to ISO-NE.
- Purpose: Compensation from ISO-NE is in part based on the quantity of time the asset provides service. Participation is broken into hourly periods, where the market participant can choose "to" or "not to" run the asset in the next upcoming hour. Unlike a generator, the BESS has a limited capacity available to charge/discharge onto the grid, if the battery were to become exhausted or conversely completely charged then the unit will be forced to drop out of participation, this is referred to as "Fading" and will accrue a penalty multiplied against that participation hour.
- Metric: Time measured as a percentage, which is (Time of Participation / Given Hour)
- Data: Time of participation for each hour the BESS participated in the market will be tracked by ISO-NE's eMarket software and will be available online.
- Analytical Methodology: Performance will be based on % time of participation in a given hour. A graph depicting average daily % time of participation will be created.
- Success Criteria: The BESS has two parameters which can affect hourly performance. First being reliability of the BESS, dropping from participation while in an operating hour due to technical issues will directly affect performance; the second is "Fading" as described earlier in this section. An overall performance of 95% has been chosen to account for limited Technical Issues and Fading.
- Name and Definition: **Revenue Generated from BESS in Regulation**, is set by ISO-NE Tariff and Market Rule and along with the Regulation Clearing Price (RCP) determines the compensation a generator accrues for participation in the Regulation Market.
- Purpose: Performance in revenue generated while operating the BESS in the ISO's Regulation Market will determine the payback performance period on the capital investment of the BESS, and provide useful data which will contribute to determine if projects of this nature are suited for financing in performance contracting such as ESPCs.

- Metric:** Hourly payments for regulation services shall be calculated as:

$$(RCP * \text{Time-on-Regulation Megawatts}) + (RCP * \text{Capacity-to-Service Ratio} * \text{Regulation Service Megawatts} * (\text{time on in minutes} - \text{fade time in minutes}) / \text{time on in minutes})$$

Where...

RCP = Regulation Clearing Price

$\text{Time-on-Regulation Megawatts}$ = Regulation Capability* (time on in minutes – fade time in minutes) / 60 minutes

“Regulation Service Megawatts = the sum of the absolute value of positive and negative movement that would occur if the Resource responded at its Automatic Response Rate without delay in pursuit of changing AGC setpoints while providing Regulation within the hour, known also as “mileage.” (ISO New England: SECTION III, MARKET RULE 1, APPENDIX J)

“The Capacity-to-Service Ratio shall be determined by the ISO. The Capacity-to-Service Ratio is the relationship between Regulation capability provided and Regulation Service Megawatts provided in an hour. Based on historical analysis, on average, one megawatt of Regulation capability will produce ten megawatts of Regulation Service Megawatts. Based on this relationship, the Capacity-to-Service Ratio shall initially be set equal to 0.1 such that the revenue associated with Time-on-Regulation Megawatts and Regulation Service Megawatts associated with a Resource providing Regulation shall be equally split. The revenue split assumption and the Capacity-to-Service Ratio may be changed from time-to-time and such changes shall be filed with the Commission for approval.” (ISO New England: SECTION III, MARKET RULE 1)
- Data:** ISO-NE will record, calculate, and provide reporting to the asset owner. A wired connection via an MPLS network, including a Router, RTU, and DMARC is required.
- Analytical Methodology:** Monthly revenue will be graphed in \$ vs Day
- Success Criteria:** At this time, limited industry research exists which would substantiate an expected payback period for energy storage participating in a Regulation market, the focus of this demonstration will be to substantiate a revenue stream. Any amount of revenue generation will be considered a successful project at this stage, where a study to focus on optimizing revenue and payback may be justified in a later demonstration; including demonstration in each ISO territory with an active Regulation market. Based on models provided by ISO-NE, our estimate is that the BESS will generate around \$8,000/mo or in the range of \$100,000/yr, pending Regulation Clearing Prices.
- Name and Definition:** The **Ease of Operational Use of BESS with ISO-NE** will serve to determine the level of operator technical training necessary to support operation of the system over its life.

- Purpose: Though the BESS will predominately run via automation, it should be determined what technical level of manual operation and monitoring will the system require while running on the ISO-NE regulation market.
- Metric: The degree of success in which the Switchboard Operator shifts learn to operate the system and respond to calls requesting readback on system status or Start-up/Shut-down of the BESS on the ISO-NE AGC signal.
- Data: Personal discussions and a survey form to collect feedback from the Switchboard Operators as well as PI.
- Analytical Methodology: Survey will be based on a scale of 1-10 for questions as they relate to ease of understanding operation of the systems.
- Success Criteria: The level to successfully understand and agree that the system is easy to monitor and operate on ISO-NE's signal should be no less than a 70%.
- Name and Definition: **Transferability of BESS to Operate at other sites** will convey the likelihood that the demonstration can be repeated with success at other installation.
- Purpose: A common goal of all ESTCP demonstrations is to determine the breadth of applicability for a technology across a multitude of federal installations. Based on technical, operational, and economic characteristics we will attempt to estimate the scale of potential to repeat for similar projects implementing a BESS and operation in an ISO Regulation Market.
- Metric: ISO/RTO policies and outlook on their individual market performance, compared to number/size of federal facilities within each ISO/RTO region.
- Data: What regions are deregulated and controlled by an ISO/RTO, which of these regions have a Regulation Market or are expected to have a regulation market meeting FERC Order 755.
- Analytical Methodology: Case by case analysis for each ISO/RTO and a general prospectus on the outlook of each individual market.
- Success Criteria: Based on the performance of the Portsmouth Naval Shipyard BESS on ISO-NE, determine by each ISO/RTO what policies or market clearing prices versus cost of technology are necessary to economically justify investment in additional systems.

4.0 FACILITY/SITE DESCRIPTION

Portsmouth Naval Shipyard is a Navy facility located in Kittery, Maine. Founded in 1800 the Shipyard has a long history of supporting the Navy fleet, from building tall ships such as the USS Constitution, to the first submarines implemented in WWI and diesel subs for WWII, transitioning to nuclear during the Cold War. Today, the Shipyard supports the retrofit and refueling of the U.S. Navy's fleet of fast attack submarines, including the Los Angeles and Virginia class.

This demonstration focuses on the Shipyard's electrical generation and distribution infrastructure. The BESS and predominant equipment for the FLS/Microgrid will be housed at the Power Plant (Bldg. 72). Additional FLS hardware and fiber optic communications will be installed on the 13.2kV electrical distribution grid at Substation 3 (Bldg. 175) and Franklin Substation (Bldg. 321).

4.1 FACILITY/SITE LOCATION AND OPERATIONS

Ameresco designed, implemented, financed and now operates and maintains the PNS Power Plant under an Energy Savings Performance Contract (ESPC) with the NAVY. Our team includes on-site fulltime staff that is intimately familiar with the shipyard's mission requirements and facility infrastructure and operations. This will assure the proper integration of the work of this study and close on-site monitoring of performance throughout the implementation and test periods. Below in Figure 4-1 is a depiction of Portsmouth Naval Shipyard, the red box indicates the bounds of this demonstration including both Phase I – BESS and Phase II – FLS systems



Figure 4-1 Portsmouth Naval Shipyard Demonstration

Figure 4-2 is a closer view of the demonstration site, which includes the Power Plant, Substation 2, Substation 3, and Franklin Station. Phase I of the demonstration will focus on the BESS which is located at the Power Plant on the 480V Station Service bus. Power is transferred from the BESS to Franklin Station via a 13.2kV loop feeder which then is stepped up to 34.5kV at the point of interconnection with the local utility. Section 5.3 addresses this architecture in further detail. For Phase II the Fast Load Shed (FLS) system will be installed with components being located at the Power Plant, Substation 3, and Franklin Station. Through these controls the Shipyard will have the capability to select a priority list for order in which loads should be shed in descending order non-essential to mission critical. First and foremost loads which support operation of the Power Plant will be kept online at all times, followed by select feeders located at the Power Plant and Substation 3 which provide power to the Dry Docks and/or other mission critical buildings. Franklin Station and Substation 2 will be isolated with all power being cut during an islanding event.

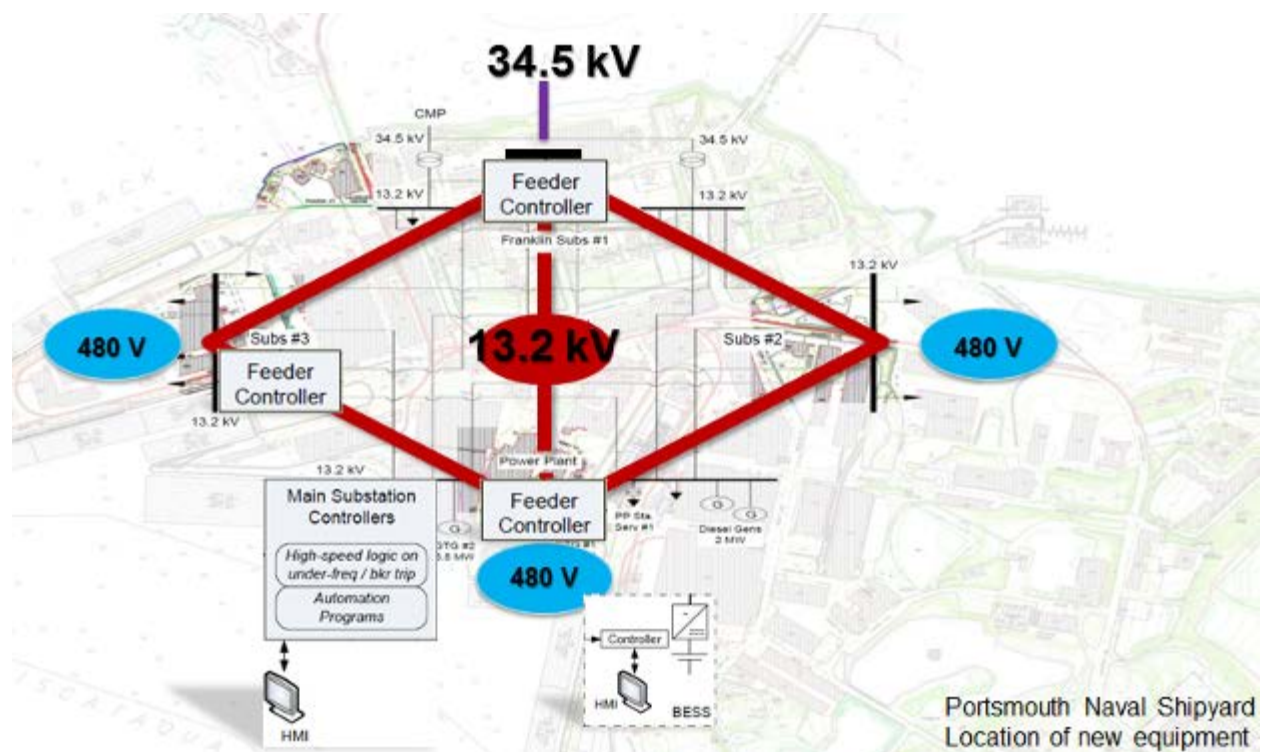


Figure 4-2 Demonstration Site

4.2 FACILITY/SITE CONDITIONS

Portsmouth Naval Shipyard (PNS) installed a 10.4 MW gas-fired combustion turbine cogeneration plant as part of a comprehensive Energy Savings Performance Contract (ESPC) executed in two phases between 2000 and 2002. The Energy Plant can operate in parallel with the Central Maine Power (CMP) utility grid or in island mode and includes: two 5.2 MW Solar combustion turbines, each with Heat Recovery Steam Generators (HRSGs) rated at 65,000 lb/hr each with supplemental fire, two 70,000 lb/hr packaged steam boilers, two 1.5 MW diesel emergency generators that support “black-start,” and a dedicated SCADA system.

The Energy Plant provides energy security (both electricity and steam) for mission-critical nuclear submarine activities on base while also producing significant energy and operating cost savings for PNS.

The proposed demonstration project would build upon the capabilities and controls of the existing Energy Plant to provide significantly enhanced energy security, and additional energy and operating cost savings to the government. The project will achieve this by focusing on two areas of concern.

Power Quality on the utility grid. Due to the success of CMP's and the state's renewable energy initiatives, approximately 30% of CMPs current power supplies come from wind-generated power. While this renewable resource provides many benefits, it does impose potential power quality issues on the grid (frequency and voltage fluctuations) due to the intermittent nature of wind power. This renders the power supply to PNS (and all other customers) less secure, and could cause additional power outages. In response to this problem, the regional Independent System Operator (ISO-NE) is developing capacity and performance payment rules for entities that provide frequency and voltage regulation capacity (also called "Ancillary Services"). The problem with current approaches to addressing this grid power quality problem is that they are very expensive to implement on a stand-alone basis and usually cannot be financially justified based on the potential Ancillary Services revenue alone. However, PNS is in a unique position to provide these Ancillary Services through a Battery Energy Storage System (BESS), at a competitive incremental cost due to the substantial electric infrastructure already in place. A new BESS would also enhance the reliability and island capabilities of the existing Energy Plant.

Loss of Grid Power and Re-Start Delay. The Energy Plant provides back-up power to mission-critical systems at the shipyard when power is lost from the CMP utility grid. To maximize the savings from the cogeneration of electricity and steam, the number of turbines on line depends upon the steam load. One turbine is always on line year around to satisfy process steam needs; the second turbine is brought on line during the winter. However, if the shipyard's total electrical demand (kW) is greater than the capacity of the operating turbine(s) when grid power is lost, then the turbine(s) become overloaded and trip out. This scenario historically occurs roughly twice a year due to weather events and other factors. (In 2011 it occurred during Hurricane Irene in August and again during a severe snow storm in October.) When this happens, plant operators must manually disconnect non-critical loads throughout the shipyard and restart the turbines. This process takes between one to three hours, during which time the entire shipyard is without power, except for isolated loads served by emergency generators and UPS systems. This vulnerability has become more pronounced in recent years as the shipyard's peak electrical demand has grown (due to growth in mission) from approximately 12 MW in 2000 to over 16 MW today. The shipyard would like to enhance the capabilities of their considerable on-site generation so that it could seamlessly serve designated critical loads without interruption whenever the utility grid is lost.

These two issues are relevant to most DOD facilities which typically have some on-site generation but are vulnerable to black-outs when grid power is lost. And their local utilities and Independent System Operators (ISOs) are increasingly grappling with grid stability issues as more intermittent renewable energy supply sources come on line. The successful demonstration of solutions to these issues at PNS would be relevant and important to nearly all military bases.

5.0 TEST DESIGN

Phase I – MCS/FLS

- **Fundamental Problem:** The DoD community has recognized that the aging infrastructure of the commercial power grid has resulted in frequent power outages. Portsmouth Naval Shipyard experiences 2 to 3 such outages each year. These outages have resulted in the tripping of the Shipyard generating plant with outages of one to three hours. Conventional automated load shed systems use individual devices or programmable logic controllers and the initiation of tripping of loads takes 250ms to seconds. The loads to be tripped were selected in pre-defined blocks to assure the system stability which typically resulted in over-tripping. The development of IEC61850 protocol with GOOSE messaging between measurement devices and the FLS controller allows for the dynamic selection of the loads to be tripped based upon the availability of generating resources. The FLS reduces the time to initiate the tripping of the selected load circuit breakers to less than 20ms.
- **Demonstration Question:** Can a Fast Load Shedding solution eliminate the outages experienced by the Shipyard while maintaining energy surety for mission critical loads? Will the Annual Avoided Cost of lost production pay for the cost for the FLS solution? Can the MCS/FLS effectively utilize BESS technology to maximize the amount of load served?

Phase II - BESS

- **Fundamental Problem:** Many government facilities utilize on-site generation in the form of Combined Heat and Power (CHP), Renewable Energy such as Solar, Wind, or Geothermal, and/or Back-up Diesel Generation; however even with these resources most sites still experience blackouts during a loss of power supplied by the electric utility. The business case and economics supporting investment in distributed generation has been substantiated and is relatively common industry practice at this point; however this is not the case for Battery Energy Storage Systems and Fast Load Shed systems which architecturally represent a Microgrid. Additional value streams can be accounted for such as generating additional revenue through participation in Ancillary Services and avoided costs in Loss of Productivity; it is the purpose of this demonstration to quantify these values.
- **Demonstration Question:** Find the breakeven point where the upfront cost of the Technology plus the revenue from Ancillary Services and savings in avoided Loss of Productivity equals the economic life of the system.

5.1 CONCEPTUAL TEST DESIGN

- **Hypothesis:** The combination of implementing a Fast Load Shed system and Battery Energy Storage System with existing on-site generation can reduce and even eliminate facility wide blackouts at a base while also creating new value streams in the form of revenue from participation of the BESS in Ancillary Services (specifically Frequency Regulation) and avoided costs related to Loss of Productivity during an extended outage. The amount of revenue generated versus expected life of the systems will determine if the technology is a good candidate for inclusion in performance contracting such as Energy Savings Performance Contracts (ESPCs) and Power Purchase Agreements (PPAs).

Phase I – MCS/FLS

- Independent variable: The Independent Variable for MCS/FLS is the calculated value of self-generation, including pre-defined margins, available to support shipyard load following the Loss of Utility event. The real measured value of the loads are then summed, based upon the operator defined priorities, until that sum is less than or equal to the available generation post LoU. The remaining loads are then tripped in high speed. The end-to-end trip execution time for the FLS is expected to be 15 to 20 ms. The overall load trip time from detection of the LoU is dependent upon the existing breaker opening time. We assume that value is 5 cycles given the age of the breakers. The MCS/FLS will be monitoring the breaker opening times as well as any failure to open. A breaker failure to trip could result in the generators tripping due to an overload as has occurred in the past. The Operator's selection of too many non-shedable loads (Priority equals 0) could also result in undesired tripping of the Power Plant.
- Dependent variable(s): The pre-LoU event values of power for the tripped loads at the Power Plant and Substation 3 will be evaluated against the settings in the C90Plus to validate the power balance calculation.
- Controlled variable(s): The existing Utility tripping scheme has is monitored by the MCS/FLS. It has not been modified so as to allow a valid comparison of the MCS/FLS with past events. Further, all loads at Franklin Substation and Substation 2 have been excluded from the generation- load power balance calculation.
- Test Design:
See Appendix B, Performance Verification Test (PVT) plan.
- Test Phases:
See Appendix B, Performance Verification Test (PVT) plan.

Phase II – BESS

The BESS did not participate in the market in 2014-2015 due to delays in signing of the interconnect agreement between the utility and the shipyard. What follows was the implementation plan for that approach.

- Independent variable: A Battery Energy Storage System consisting of a 500kW Power Conversion System (PCS) and a 580kWh Li-Ion Battery will be introduced to the Portsmouth Naval Shipyard's electrical grid, behind the meter, and used to participate in the ISO-NE Regulation market.
- Dependent variables:
 1. *Regulation Clearing Price* is set in the ISO-NE bid market, for the demonstration period the system will serve as a price taker and will not attempt to influence the clearing price.
 2. *Time ON Regulation* is the units of time in minutes that the system operates within a given hour.
 3. *Fade Time* is the units of time in minutes that the system reaches an upper or lower limit in State of Charge (SOC) which prevents the BESS from continuing to provide Regulation service.

4. *Regulation Service Megawatts* is the sum of the absolute value of positive and negative movement that would occur if the resource responded at its Automatic Response Rate without delay in pursuit of changing AGC setpoints while providing Regulation within the hour, known also as “mileage.”
- Controlled variable: Participation in ISO-NE Regulation Market will be broken into one (1) hour blocks of participation with the intent to operate as many hours as possible for the duration of the demonstration period. The target will be operation 24/7 for a period of four (4) months from December 2014 through March 2015.
 - Test Design: The BESS will be allowed to run on the ISO-NE Regulation market 24/7 over a four (4) month period beginning December 1st 2014 and ending March 31st 2015. Success in performance of the system for Phase I will be measured in the BESS’ ability to create a new revenue stream through participation in ISO-NE’s Regulation Market. The revenue generated by the BESS in Regulation can then be used in part to determine the economic value of investing in the technology when comparing the following metrics.
 1. Upfront Cost of Investment
 2. O&M Cost
 3. Useful Life
 4. Battery Re-gen Cost
 5. Number of Battery Re-gens
 6. Avoided Cost of Lost Production (To be performed in Phase I)
 - Test Phases:
 1. Commissioning
 2. Commence Participation in ISO-NE Regulation Pilot
 3. Collect ISO-NE Monthly Reports
 4. Conclude Participation in Pilot
 5. Collect D400 Logger Data
 6. Performance Analysis
 7. Economic Analysis

5.2 BASELINE CHARACTERIZATION

Phase I – MCS/FLS

- Reference Conditions:
 1. Number of Loss of Utility Events causing tripping of Power Plant
 2. Length of outage for each event
 3. Cost of lost production for each event
 4. Power Plant power output at time of event.
 5. Other significant issues due to outages

- Existing Baseline Data: Obtain outage records from NAVFAC.
- Baseline Estimation: The PI will research the operational records for the Shipyard to establish the number of historic Loss of Utility events. The PI will establish the length of each outage. The PI will work with Shipyard Operations to establish an estimated hourly cost and the average load in MW being served. This data will allow for the calculation of a yearly cost, or Annual Avoided Cost, for Loss of Utility Events.

The PVT results as well as three real life events during the demonstration period showed that the Power Plant could have remained online if the Franklin breakers were either 1) directly tripped by protective relays at Franklin, or were tripped by a high speed transfer trip signal from the CMP feeder breaker. See Section 6.0 and 8.0 for further details.

- The FLS has demonstrated that the high speed tripping of non-critical loads will maintain a steady-state generator-load balance that will allow for the Power Plant to continue to serve the mission critical load following a fault on the utility feeder. The Diesel Generators (3MW) were started by the Plant DCS during the Live Testing and helped with the quick restoration of power to Shipyard load. It may be that PNS or the PI can provide these details.
- Each F35 Controller has a circular event log. These event logs are automatically retrieved by the HMI/SCADA using the GE Integrator software. The data is time stamped and assembled in a time sequence report by the HMI. The Event Logs for the Live Testing are available in Appendix C.
- Data Collection Equipment: The FLS system will utilize GE F35 Feeder Protection Relays to collect generation and load data by measurement of power, voltage and current. The F35 provides an economical retrofit solution for existing switchgear as one F35 can monitor a single Bus Voltage and the currents for five circuit breakers or two bus voltages and current from four feeders. The D400 gateway will monitor the status of the BESS and the charge/discharge power of the BESS for inclusion in the FLS calculations by the C90Plus FLS Controller.

The data collected by the MCS FLS proved to be very valuable in verifying the proper performance of the MCS FLS during the Simulated Tests that were conducted on December 3, 2015 and the Live Tests conducted on December 8, 2015. Subsequent events during the Demonstration Period have proved the value of the Data Collection capabilities of the MCS/FLS.

Phase II - BESS

- Reference Conditions:
 1. Regulation Clearing Price (RCP)
 2. Battery State of Charge (SOC)
 3. Automatic Generator Control (AGC) Signal
- Existing Baseline Data: Historic *Regulation Clearing Prices (RCP)* can be obtained from ISO New England's website, as seen in Figure 5-1. Samples will be downloaded and used to set monthly averages to be compared to the values collected during the demonstration period.

ISO new england

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November 17, 2014	11/17/2014 11:00 PM EST	CSV
November 16, 2014	11/16/2014 11:00 PM EST	CSV
November 15, 2014	11/15/2014 11:00 PM EST	CSV
November 14, 2014	11/14/2014 11:00 PM EST	CSV
November 13, 2014	11/13/2014 11:00 PM EST	CSV
November 12, 2014	11/12/2014 11:00 PM EST	CSV
November 11, 2014	11/11/2014 11:00 PM EST	CSV

IN THIS SECTION

- Energy**
 - Hourly Day Ahead LMPs
 - Hourly Day Ahead with Preliminary Real-Time LMPs
 - Preliminary Real-Time Five-Minute LMPs
 - Preliminary Real-Time Hourly LMPs
 - Final Real-Time Hourly LMPs
 - Selectable Day-Ahead and Real-Time Hourly LMPs
 - Weekly LMP Indices
 - Monthly LMP Indices
 - Zonal Information
- Offers, Bids & Threshold Prices**
 - Price Responsive Demand Offers
 - Daily Offer Threshold Price
 - Day Ahead Energy Offer Data
 - Real-Time Energy Offer Data
 - Real-Time and Day-Ahead Import Offer and Export Bid Data
 - Day-Ahead ARD Bid Data
 - Real-Time ARD Bid Data
 - FCM Annual Reconfiguration Auction Offers and Bids
 - FCM Monthly Reconfiguration Auction Offers and Bids

Figure 5-1 Historic Regulation Clearing Prices

<http://www.iso-ne.com/isoexpress/web/reports/pricing/-/tree/ancillary-hourly-rcp-final>

Sample CSV File Data from ISO-NE Website

Real-Time Final Hourly Regulation Clearing Prices			
Filename: final_hourlyrcp_20141119_20141119.csv			
Report for: 11/19/2014 - 11/19/2014			
Report generated: 11/20/2014 15:46:31 EST			
Day Date	Hour Ending String	Regulation Price \$/MWh	Clearing
11/19/2014	1		16.04
11/19/2014	2		10.36
11/19/2014	3		11.61
11/19/2014	4		8.5
11/19/2014	5		8.44
11/19/2014	6		92.35
11/19/2014	7		44.55
11/19/2014	8		35
11/19/2014	9		24.2
11/19/2014	10		27.47

Figure 5-2 represents Four-second AGC Setpoint Data for a Basecase ISO-NE Trinary Dispatch from representative simulations under identical system conditions for a set of conditions important to normal AGC dispatch. This data was developed in collaboration with DNV/GL (formerly KEMA) using the KERMIT simulation environment. KEMA simulated in open-loop the four-second AGC Setpoints for a set of 15 different resource characteristics taken two at a time (as specified by the 135 scenarios delivered by ISO) in order to investigate how these varying characteristics will affect the AGC Setpoints sent to the two individual resources. The set of 135 scenarios is arrived at by using the probability concept of combinations: 135 is equal to 16 (fifteen resource characteristics plus one null-set where only one resource is dispatched by AGC) choose 2 at a time (which equals 120), plus 15 repetitions (e.g., resource type 1 and resource type 1 are both dispatched by AGC, type 2 and type 2 are both dispatched by AGC, etc.). The state of the system was summarized for a set of seven days deemed by ISO to be fully representative of the set of conditions important to normal AGC dispatch. The data delivered to ISO are those simulated four-second AGC Setpoints for each resource for all seven days of each of the 135 scenarios and validation was performed on this data in order to verify to ISOs satisfaction that this data is representative of the AGC Dispatch that would have occurred given the assumptions.

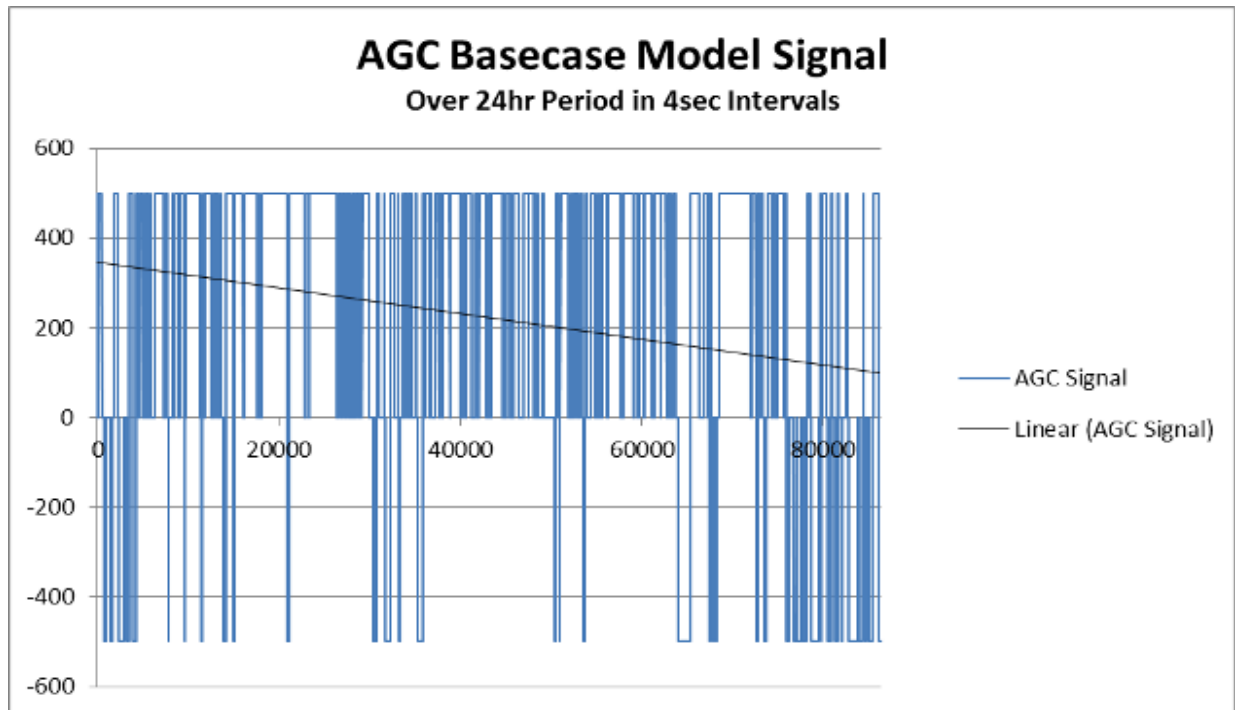


Figure 5-2 AGC Signal Model Data from ISO-NE

# of Times Reg High/Low/Mid Occurs			
Mid	Low	High	Total
6113	12533	2939	21585
28%	58%	14%	100%

- Data Collection Equipment:

1. General Electric D400:

This unit will be used to log data at the Modbus communication level between the RTU, Site Controller, PCS, and Battery. The pointlist is extensive and covers more parameters than we expect to be relevant for the demonstration analysis however we have decided to capture all operating data since the D400 contains sufficient memory to do so.



2. Schneider Electric Laboratory Solutions SEL-735:

This power quality and revenue grade meter serves two purposes in the demonstration; first is to report system response performance in kW back to ISO-NE with 0.3% accuracy in 4 second intervals, second is to log data useful for baseline and performance measurements such as the kW response and power quality metrics like Voltage, Amps, Frequency, and n^{th} Harmonics.

SEL SEL-735 Power Quality and Revenue Meter



The SEL-735 meter combines leading power quality capabilities with exceptional revenue metering accuracy at an economical price. Power quality reports with IEC 61000-4-30 compliance help identify and troubleshoot problems in power system equipment. Advanced communications deliver critical and historical information in real time to virtually any communications system. The SEL-735 is the essential meter for substation, power plant, and industrial metering.

5.3 DESIGN AND LAYOUT OF TECHNOLOGY COMPONENTS

Phase I – MCS/FLS

- System Design: A Microgrid Control System (MCS) consisting of a Fast Load Shed (FLS) scheme is being implemented to detect a Loss-of-Utility (LoU) event and initiate Fast Load Shedding to maintain power balance for the Shipyard. The FLS consists of C90Plus FLS Controller that calculates power balance for the Power Plant and Substation 3 of the Shipyard. The loads served by Franklin Substation and Substation 2 were excluded in the Demonstration to minimize the installed cost of the MCS/FLS.

F35 Feeder Controllers are installed on key circuit breakers at the Power Plant and Substation 3. These F35s monitor the breaker real time status and power measurements and communicate them C90Plus FLS Controller via IEC 61850 GOOSE message. A F35 is installed at Franklin Substation to detect the LoU event initiation by the existing protection and control system. This F35 also provides real time power measurements of the utility ties and status of the circuit breakers to the MCS HMI/Server.

The C90Plus calculates the post LoU power balance for the Shipyard and, upon detection of a LoU, will send trip signals to lower priority loads to maintain the power balance. The FLS also initiates tripping of three circuit breakers at Franklin Substation to avoid possible back feed from Substation 3. All trip signals are transmitted via a GOOSE message to the F35 relays. The fast (15 to 20ms) initiation of tripping of the loads by the FLS should allow the Power Plant to remain in-service instead of tripping due to a severe power imbalance as has occurred in the past. The FLS programming will allow Shipyard operators to maintain power flow to mission critical loads.

An option is included in the design to have the D400 Data Gateway & Controller monitor the status and real power flow to/from the BESS prior to LoU and input this power value to the C90Plus controller for inclusion of available BESS margin in the power balance calculation. If enabled, the D400 will initiate a full discharge of the BESS to provide additional load support for the Shipyard until the Diesel-Generators have started and are ready to pickup load. The start-up of the Diesel-Generators is automatically initiated by the Power Plant DCS upon detection of the LoU. The LoU detection signal for the DCS is used by the MCS/FLS. This option will provide up to 1MW of additional load support.

- **Components of the System:** The MCS/FLS consists of the following major components. All of these components are commercially available and have been applied in customer facilities.

GE Multilin C90Plus Fast Load Shed Controller:

The controller is the main decision point of the system where all the calculations and intelligent commands are sent. It is a substation hardened device with a real-time operating system that is highly reliable and accurate. It is also equipped with a local annunciator panel and HMI screen (optional) for ease-of-use for maintenance and operation and embedded IEEE 1588 time synchronization protocol support. The controller receives source and load data from the F35 via analog GOOSE. The load shed commands are issued via GOOSE to end devices. The C90Plus Controller is installed in a Rack at the Power Plant with the F35 Relays.



GE Multilin F35 Feeder Protection Relays: The FLS utilizes F35 feeder protection system to provide feeder protection, control, monitoring and metering in an integrated, economical, and compact package. The F35 provides a cost-effective solution as the F35s are configured to protect up to five feeders with bus voltage measurement. It also provides fast and deterministic execution of programmable logic, which is necessary for substation automation applications. The F35s have embedded IEEE 1588 time synchronization protocol support over Ethernet.



GE Multilin D400 Data Gateway & Controller:

GE's Multilin D400 is a secure, hardened, advanced substation gateway that collects metering, status, event, and fault report data from serial or LAN based intelligent substation devices and accepts time sync signals from SNTP/NTP Servers,. The Multilin D400 summarizes data from the substation devices and makes it available locally /remotely through a standard secure web browser (HTTPS). It supports serial and/or LAN connections to SCADA masters.



The Multilin D400 provides the computing platform necessary to automate substation procedures, such that intricate processes are carried out safely and efficiently by creating custom automation programs using IEC 61131 compliant tools, and perform basic math functions on data points using the built-in calculator tool. Using pass-through connections, users can extract valuable non-operational data such as digital fault recording (DFR) records, event and oscillography files. The user can also access the historical log files and upload the archived data for trending and analysis.

GE Multilin ML3100 Managed Ethernet Switch:

The MultiLink™ ML3000 Series of Managed Ethernet Switches provide extremely reliable networks and feature SMART RSTP feature allows for recovery from faults in ring network architectures in less than 5 milliseconds per switch in the network – 10 times faster than generally available in standard Ethernet. The complete set of network management functions available provides the configurability and monitoring capability needed for most applications, while the high level of security features available ensures your network is protected from tampering or illegal access. The ML3100 series supports the end-to-end transparent clock, boundary clock and ordinary clock as specified in the IEEE 1588v2 standard. Ambient operating temperature is -40°C to +85°C without fans.

**Arbiter Systems 1084B GPS Satellite Controlled**

Clock: The overall time synchronization of the MCS/FLS components is effected by the application of the Arbiter 1084B clock with GPS Satellite Antenna The Model 1084B provides the most-needed GPS system clock features in an economical package and adds an LCD setup/status display and keyboard. The Clock is equipped a Network Time Protocol / Precision Time ProtocolServer option allows the Arbiter Clock to act as a time server over an Ethernet network using the Network Time Protocol (NTP) and the Precision Time Protocol (PTP). The Precision Time Protocol Server supports the IEEE 1588-2008 protocol and functions as a grandmaster clock. NTP accuracy is better than 100 microseconds and PTP accuracy is better than 1 microsecond.



Dell PowerEdge 720xd 2ru Rack Mounted Server: Equipped with 2.5 GHz Xeon CPU, 16 GB RAM, 750 W power supply, 2 hot swappable 1 TB SATA HDD with RAID 1, and Dual 1 GB Network Interface Card, Microsoft Windows Server 8. A separate 42” LG LED-backlit LCD display panel is being provided.



Software included for the HMI and Data Storage:

GE PMCS/Cimplicity 9.0 SCADA Software:

Based on decades of GE innovation, award winning Proficy HMI/SCADA – Cimplicity 9.0 delivers a proven platform to precisely monitor and control every aspect of the MCS environment, equipment and resources. Cimplicity improves your structured database quickly and easily, enabling RtOI – for the right information, anytime, anywhere. With Version 9.0, you can create longer point names including alarm, event and action IDs – now up to 256 mixed case characters. With this more descriptive database, improved tree views and richer objects, you’ll have better interaction with newer protocols, ease maintainability, and see improved modeling and a richer experience.



Keeware KEPServerEX is the industry’s leading communications platform that leverages OPC (the automation industry’s standard for interoperability) and IT-centric communication protocols (such as SNMP, ODBC, and web services) to provide users with a single source for industrial data. Designed around the four product pillars of Proven Interoperability, Centralized Communications, On-Demand Scalability, and Industrial Strength, KEPServerEX is developed and tested to meet our customers’ performance, reliability, and ease-of-use requirements. It is equipped with Modbus Suite for high speed data retrieval of real time power system values and alarm events from the GE Devices.

GE EnerVista™ Integrator enables seamless integration with GE’s Multilin™ devices for new or existing automation systems through tested, pre-configured memory maps. EnerVista Integrator reduces the setup and commissioning efforts required to obtain device, event and waveform data by over 90% for integration with an HMI, SCADA or DCS system.

- System Depiction: See Figure 5-3 below and Appendix E for a System Architecture Diagram

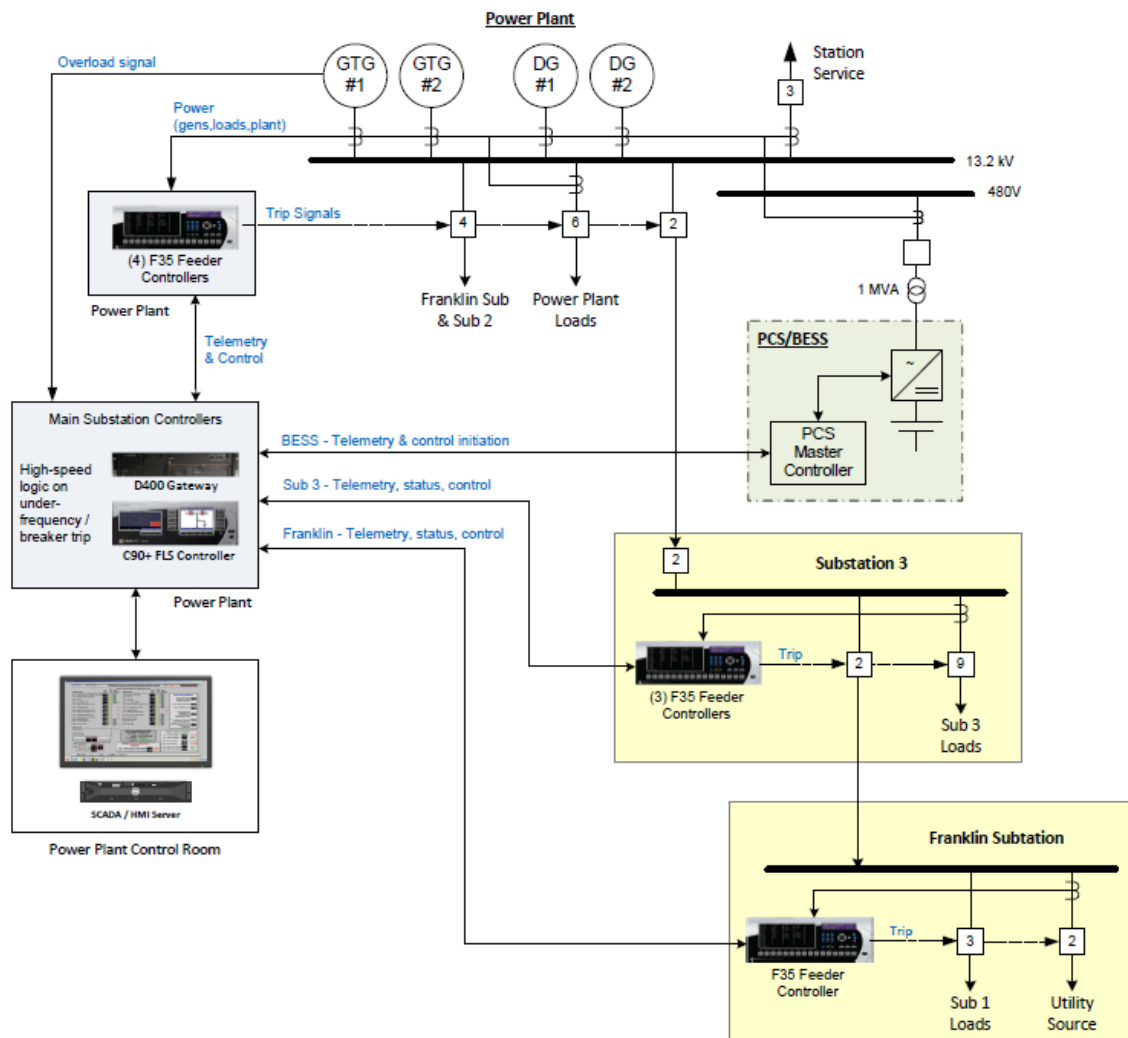


Figure 5-3 System Architecture Diagram

- **System Integration:** The design concept for integrating the MCS/FLS system was for it to coexist with the existing systems. The physical interconnections have been designed for easy removal at the end of the demonstration period, if desired. All existing protection and control functions continue to operate as if the MCS/FLS did not exist. The design also allows for future expansion of the system to include loads at Substation 2 and Franklin Substation.
- **System Controls:** Operations raised a concern that resulted in the design being modified to incorporate Local/Remote (43L/R) switches to provide operations personnel to disable control of a circuit breaker during maintenance. The L/R contacts are being monitored by the F35 relays and alarmed at the HMI to assure that they are not inadvertently left in a Local Mode. The C90Plus will continue to function, but the specific breaker will be treated as a High Priority load if the breaker is placed back into service. The F35s have been equipped with Test Switches that open the trip circuits to allow for testing of the relays. The F35s include Trip Circuit monitoring that will detect the open trip circuit and initiate an alarm at the HMI and relay.

Phase II – BESS

- **System Design:** The Portsmouth Naval Shipyard electrical grid infrastructure consists of two major substations (Sub 2, Sub 3), a CHP Power Plant, and an interconnection with the public utility (Franklin Sub). These four stations are connected at the 13.2kV via loop feeders with each station then distributing 480V service to various loads on the yard. Looking back to Figure 5-3 above, the BESS is located at the Power Plant as depicted within the dashed line box. A full size drawing can be found in Appendix E.
- The system consists of a 500kWh Li-Ion battery, 500kW Power Conversion System (PCS), Site Controller, Remote Terminal Unit (RTU), and Router providing communication to/from ISO-NE across an MPLS network.

During Phase I of the demonstration the Fast Load Shed, consisting of the Main Substation Controllers, HMI, Feeder Controllers, and Trip Signals, will not be installed. They will be part of Phase II, once the BESS has completed demonstration in the ISO-NE Regulation Pilot.

- **Components of the System:** The BESS consists of three major components, a 580kWh Li-Ion Battery, 500kW Inverter/Rectifier (PCS), and Site Controller. Additional communications necessary for participation in the ISO-NE Regulation market include a Remote Terminal Unit (RTU), Power Quality and Revenue Meter, and Router.

580kWh Li-Ion Battery – Manufactured by Saft America, the IM20 unit is built on a containerized platform. The container is populated with ten (10) battery strings wired in parallel, with each string consisting of twenty eight (28) modules wired in series. The unit is self-contained and includes the HVAC and Fire Suppression systems necessary for safe operation. Auxiliary power for the battery management, HVAC, and Fire Suppression system are fed separate from the battery via independent 480V and 120V service fed from house power.



500kW Power Conversion System (PCS) – Produced by Dynapower Corporation, this unit houses an Inverter, Rectifier, and Isolation Transformer which serves to charge/discharge the battery from/onto the electrical grid at a 480V 3 Phase level. The unit is actively liquid cooled and includes a top mounted liquid/air heat exchanger. Auxiliary electronics, fans, and pumps are powered internally via the PCS' 480V connection on the Station Service bus.



Site Controller – Also manufactured by Dynapower Corporation, this unit consists of a Central Processing Unit (CPU), Analog I/O board, Digital I/O board, Ethernet Hub, and Human Machine Interface (HMI) touch screen. This is the primary interface for manual and remote operation of the BESS, from this point operator commands and system limits are processed based on data collected from the Battery and PCS. This is also the location where the ISO-NE communications hardware is housed, which includes the RTU and Router.



RTU – The Remote Terminal Unit selected for this project is manufactured by OSI, the model is the OSIRIS and comes with a number of different communication ports including Digital I/O, Analog Inputs, Serial, and Ethernet ports. The unit is connected solely by Ethernet and serves to translate the Modbus communications coming from the Site Controller to DNP3 which is then relayed to the Router for communication to ISO-NE.



Router – The Cisco 1941 series router is supplied by ISO-NE and serves as the primary connection and firewall to their dedicated MPLS network. Data packages containing operating commands and performance information are received and sent in both directions between the BESS and ISO-NE. This is a live connection with a 4 second sample rate. Included in the router is a 3G wireless Enhanced High-Speed WAN Interface Card (EHWIC), purposed as a back-up form of communication to/from ISO-NE in the event of a failure of the land-based circuit.



Power Quality Revenue Meter – ISO-NE requires a Power Quality meter that can report within 0.3% accuracy performance of the regulation resource, ie. BESS. The SEL-735 is programmed to communicate via Modbus over Ethernet the power in kW to the RTU, which is then translated via the Cisco router back to ISO-NE. The Current Transformers (CTs) for this unit are installed between the PCS and Station Service bus, effectively reporting the “gross” power response which includes the auxiliary power necessary to operate the PCS. See Figures 5-4 and 5-5 for further installation details.

SEL-735 Power Quality and Revenue Meter



The SEL-735 meter combines leading power quality capabilities with exceptional revenue metering accuracy at an economical price. Power quality reports with IEC 61000-4-30 compliance help identify and troubleshoot problems in power system equipment. Advanced communications deliver critical and historical information in real time to virtually any communications system. The SEL-735 is the essential meter for substation, power plant, and industrial metering.

- System Integration: The BESS is tied into the existing Station Service bus by breaker 52G as seen in Figure 5-4. This breaker was previously purposed for an emergency diesel generator which had since fallen into disrepair and made obsolete at the time of installation of the two (2) 1.5MW during construction of the CHP plant. This drawing is a simplified one-line representation of the BESS' relationship to the public utility interconnection. The BESS is tied into the electrical grid at the 480V level of the Station Service bus which is fed by 480V/13.2kV transformer(s) at the Power Plant. Loop feeder(s) then connect the Power Plant to Franklin/Franklin Annex (Substation 1 in Figure 5-4) which then finally translates via F1 or F12 through 13.2kV/34.5kV transformers to the public utility.

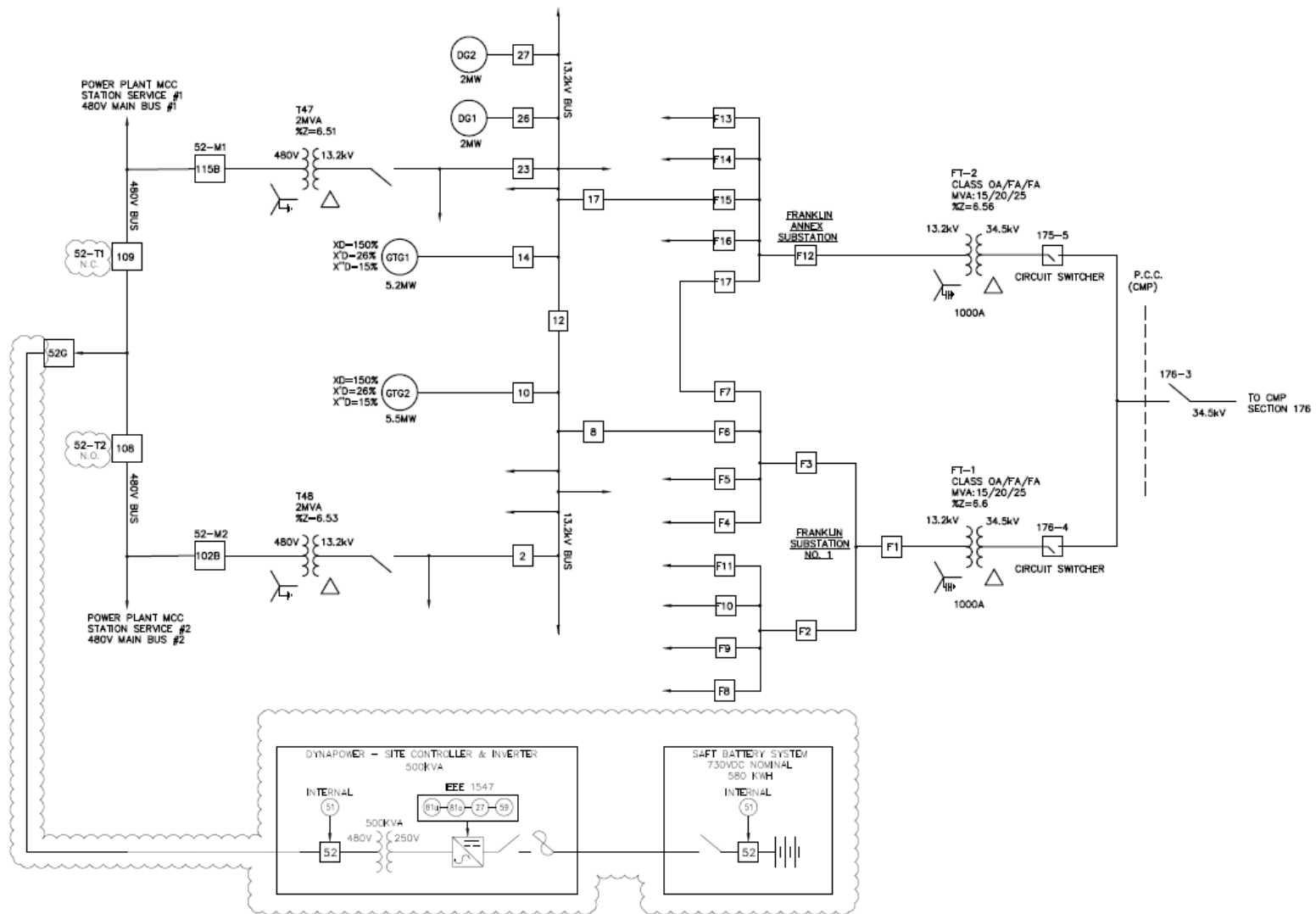


Figure 5-4 BESS Electrical Connection Diagram for PNS As-builts

This drawing can also be found in Appendix G along with the full BESS As-builts.

Figure 5-5 is the detailed installation drawing for the SEL-735 Power Quality and Revenue Meter, notice that the PTs and CTs are installed between the PCS and Station Service bus, mounting in this location provides a calculation of “gross” power, effectively measuring the charge/discharge of the PCS as well as the auxiliary loads (such as controls, fans, and pumps) necessary to operate the PCS.

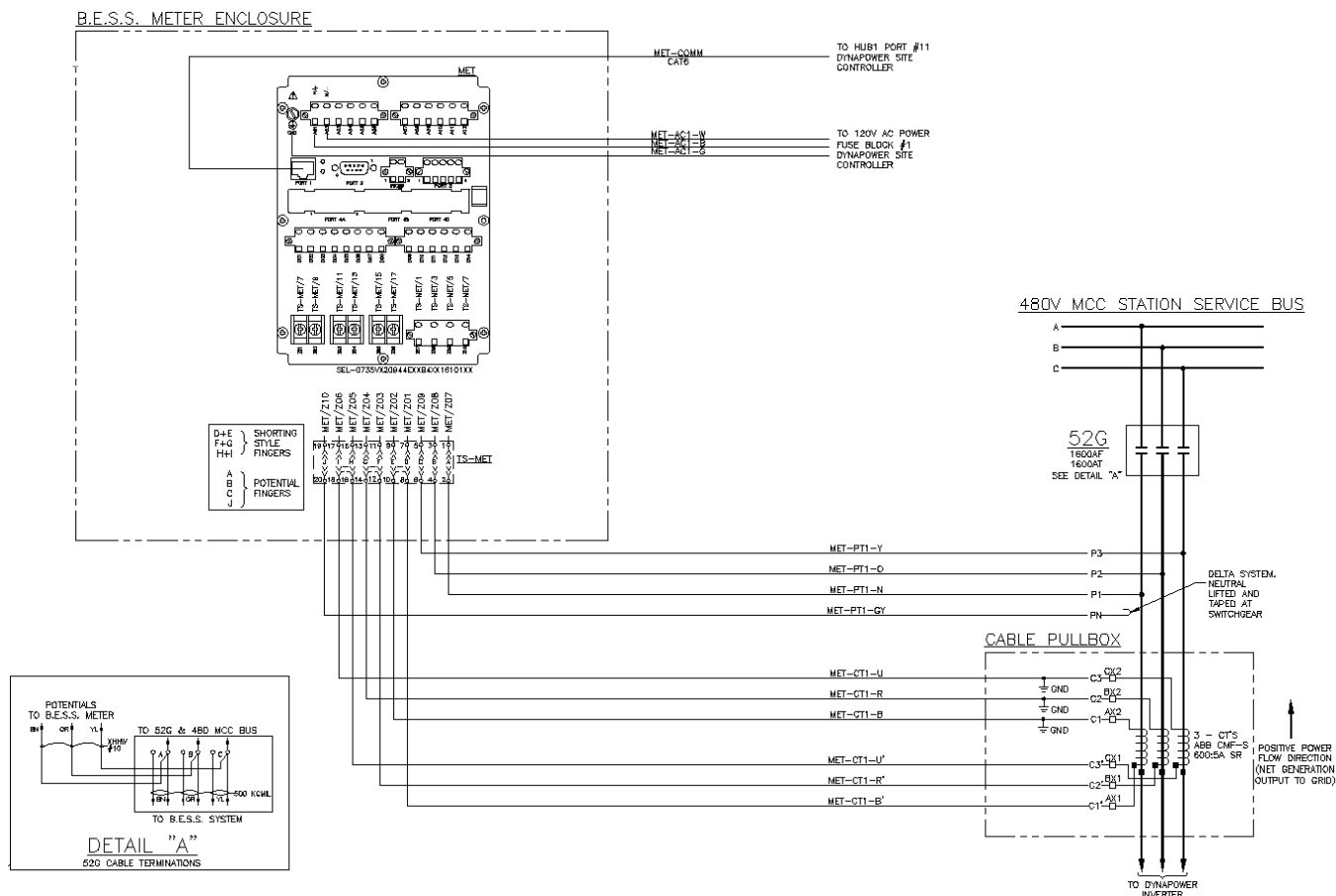


Figure 5-5 Detailed Installation Drawing for SEL-735 Power Quality and Revenue Meter

This drawing can also be found in Appendix G along with the full BESS As-builts.

- **System Controls:** The following screen shots represent the HMI touch screen found on the front of the Site Controller. Three operating modes are built into the design, Remote Dispatch, Automatic Voltage Regulation, and Microgrid Dispatch; in addition the system can be run manually in local mode. For Phase I of the demonstration only the Remote Dispatch mode will be used and steps to operate are detailed as follows.

Command Menu

Start
Stop
Reset

Current Output:

Output kW: **0.0**

Output kVAR: **0.0**

0.0 AVR Set Point (V)

New Settings:

0.0 kW

0.0 kVAR

0 kW/S

Set Run Mode:

Remote Dispatch

AVR Mode

Menu

O
R

SC: Initializing

PCS: Initializing

Meters

Figure 5-6 Dynapower Site Controller Command Screen

1. Put Site Controller in Remote Dispatch mode (press “Remote Dispatch”)
2. Select Ramp Rate (press blue box next to “kW/s”, enter value)
3. Leave “kW” and “kVAR” at “0” values
4. Bring PCS Online (press “START” button)

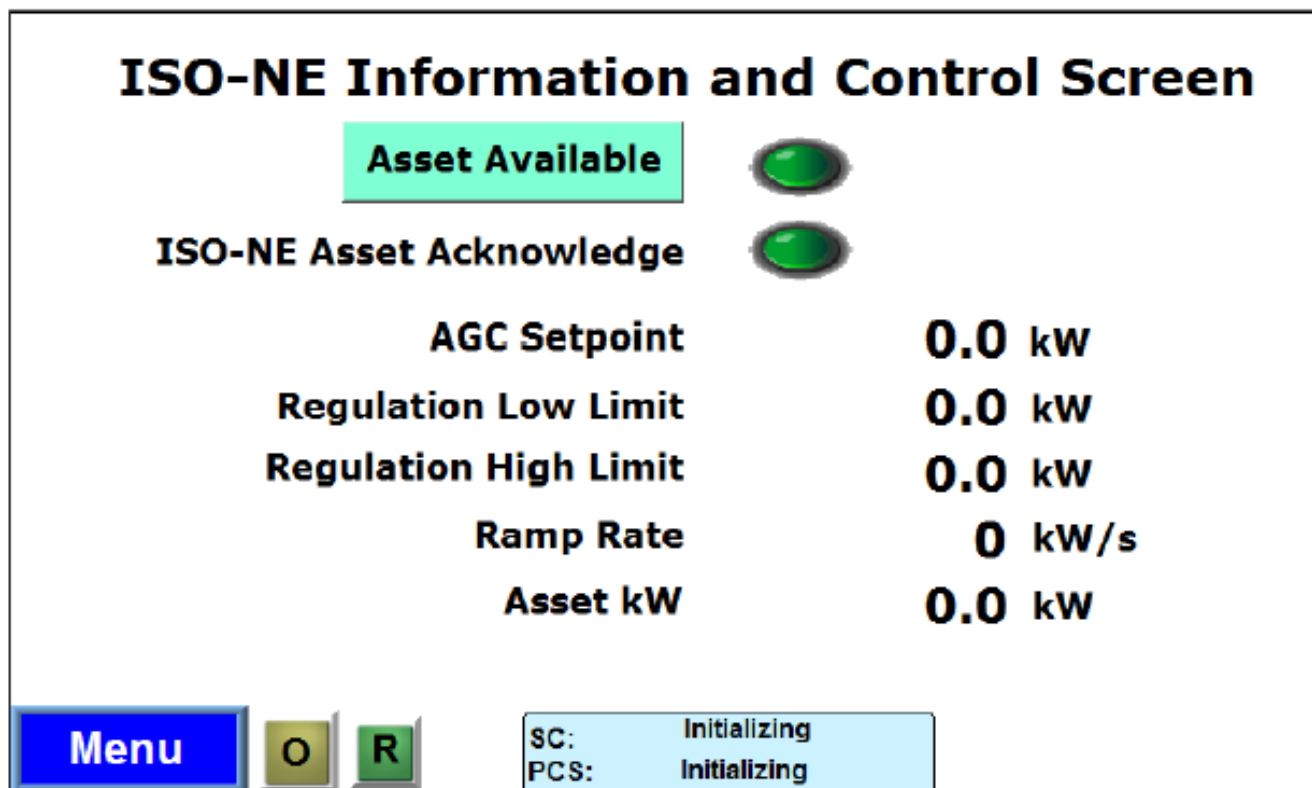


Figure 5-7 Dynapower Site Controller ISO-NE Screen

1. Send Asset Available status to ISO-NE (press “Asset Available”)
2. Receive Asset Acknowledge from ISO-NE (status light illuminated)
3. Asset begins following AGC Setpoint
4. IF “Asset Acknowledge” is dropped by ISO-NE, unit goes into STOP

A full stop can also be initiated by pressing the “STOP” button on the Site Controller Command Menu or by depressing any one of the seven “E-STOP” buttons. Additional protective monitoring is programmed into the Site Controller and will STOP the BESS in the event of a Battery, PCS, or Site Controller fault. Also, for Phase I the BESS will go into Stand-by in the case of an Islanding event, this prevents the BESS from continuing to follow the ISO-NE AGC signal while isolated from the local electric utility. In Phase II the BESS will turn over to Microgrid Dispatch mode during an Islanding event. Wiring details for the E-STOP and Protective Monitoring are found in Figure 5-8 as well as Appendix G.

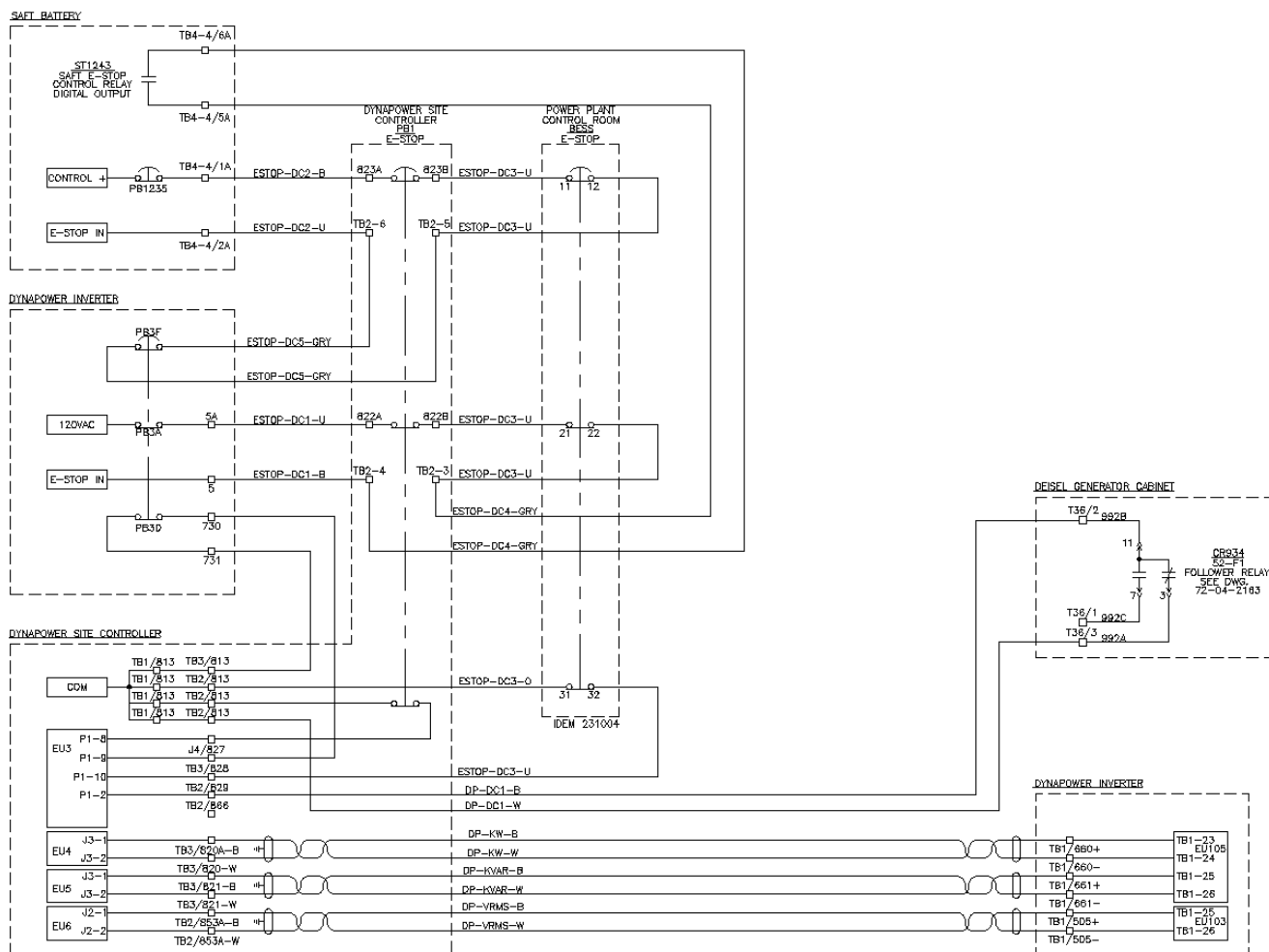


Figure 5-8 BESS E-Stop Schematic from PNS As-built

5.4 OPERATIONAL TESTING

Phase I – MCS/FLS

- Operational Testing of Cost and Performance: The MCS/FLS will collect power, voltage and current values for monitored circuit breaker. The F35 relays are mounted in Racks and the phasing and measured values were verified during Factory Acceptance Testing. The Commissioning tests will utilize Doble F6150 Relay Test sets. The analog input to the relays will be verified during the Commissioning Tests. The HMI analog values will all be verified at the same time thus assuring data accuracy. The final verification will be made during the Performance Verification Tests as the Doble Test Sets will be used for offline testing of the Solution. The accuracy of the F35 relays will also be verified against existing meters once the relays are connected to the potential transformers and current transformers during online testing.
- Modeling and Simulation: No modeling or simulation will be performed.

- **Timeline:** The MCS/FLS Solution underwent Site Commissioning and Performance Verification Testing per the following Schedule:

Monday	Tuesday	Wednesday	Thursday	Friday	Saturday
9/7/2015	9/8/2015	9/9/2015	9/10/2015	9/11/2015	9/12/2015
Holiday	Travel	<=====Pre-Commissioning=====>			
9/14/2015	9/15/2015	9/16/2015	9/17/2015	9/18/2015	9/19/2015
<=====Site Commissioning=====>					Off
9/21/2015	9/22/2015	9/23/2015	9/24/2015	9/25/2015	9/26/2015
<=====Site Commissioning=====>					Off
12/7/2015	12/8/2015	12/9/2015	12/10/2015	12/11/2015	12/12/2015
Prep	<=Performance Verification Testing=>			Debrief	Off

Figure 5-9 MCS/FLS Commissioning and PVT Schedule

Please see GE Site Commissioning Plan (SCP) and Performance Verification Testing (PVT) plans included in Appendix B, the following are excerpts taken from those documents

Overview of the Site Commissioning Plan is as follows:

The following sections present overview of all chapters of this document and associated tests. It is the intention that every individual analog or digital input and output will be tested and verified during this test.

1. Pre-testing Inspections

- The inspections presented in Chapter 2 confirm that all hardware and software has been properly installed and the FLS system is available for testing.*

2. System Startup and Integrity Tests

- The tests described in Chapter 3 verify proper device and system startup and proper communications of all devices for the FLS. This includes the MCS HMI Server, C90+ Fast Load Shed Controller, F35 Multi- feeder Management Relays, GPS clock, and networking equipment.*

3. Relay GOOSE Communications Tests

- The tests described in Chapter 4 will verify the proper communication between the FLS Controller, MCS HMI, and F35 relays.*

4. System I/O Tests

- The tests described in Chapter 5 verify the processing within the system of all I/O points, including proper Display of their statuses and values in the MCS HMI Server. Both hardwired I/O points and the points polled from the F35 relays (soft I/O points) will be tested.*

5. Testing Restrictions

- When actual operation of the breaker(s) is not possible, the physical I/O shall be verified to the closest termination practicable.*

6. HMI Tests

- a. *The tests described in Chapter 6 will verify the functionalities and screens configured in the Microgrid Control System (MCS) Human Machine Interface (HMI).*

7. System Time Synchronization Tests

- a. *The tests described in Chapter 7 verify the MCS Time Synchronization to the GPS clock.*

Overview of the Performance Verification Test Procedures (PVT) is as follows:

FLS System Operation during PVT

The recommended method of verification that the FLS system is operating as designed is the trigger a number of actual load shed events, using several different Load Priority configurations to create different scenarios for shedding of loads. This live testing is subject to the approval and participation of NAVFAC personnel. Each scenario will be detailed on the Fast Load Shed Live Testing Configuration Form.

Live Fast Load Shed Verification

Using the “Fast Load Shed Live Testing Configuration Form”, the settings of each FLS scenario will be recorded. The individual breaker loads and priority assignments are recorded, along with the loads being supplied by all available sources.

Once the desired test scenario has been programmed via the HMI FLS Configuration screen, the settings are recorded on the form. The total Facility load being supplied is totaled manually and entered in the appropriate space on the form. The Load to Be Shed will be the result of the Utility load minus the available online generation supply.

The loads expected to be shed are noted in the column “Expected Shed”

After the Load Shed Event, the loads actually shed will be noted in the “Actually Shed” column. The scenario will then be evaluated and the “Expected Shed” will be compared against the “Actually Shed”, and the FLS response will be evaluated.

Oscillography records can be downloaded from the individual relays and analyzed. The HMI Event database and the HMI Alarm database can likewise be analyzed.

One form will be completed for each scenario being tested.

Results from both SCP and PVT are included in the final documents found in Appendix B of this report.

Phase II – Operation of BESS in ISO-NE Regulation Pilot

Installation of the BESS commenced in April 2014 and was completed in May 2014. Commissioning was completed during June 2014 and entailed a list of system checks of each primary piece of equipment including Battery, PCS, and Site Controller; followed by a series of real-time operational tests of the BESS on the ISO-NE AGC signal.

Participation in the ISO-NE Regulation Pilot was to commence once an Interconnection Agreement was reached between the Navy and Central Maine Power. Pending signing of the IA, the BESS was expected to run 24/7 from mid-December through March 31st 2015. Performance data was to be collected over this period with the expectation that during this time operating characteristic of the AGC signal would vary depending on time of day, weather conditions, and utility outages.

Though system checks while connected to ISO-NE were performed and successful operation was confirmed, a signed IA between the Navy and Central Maine Power was not obtained in time for participation in the ISO-NE Pilot program.

(Copies of the IA and modified Navy contract with CMP can be found in Appendix F)

Looking back to Phase I, the BESS was integrated and tested in conjunction with the GE FLS to demonstrate operation as both a “Buffer” and “Bridge”.

	May 2014		June 2014		July through Nov		December 2014		January 2015		February 2015		March 2015	
Week	1-2	3-4	1-2	3-4			1-2	3-4	1-2	3-4	1-2	3-4	1-2	3-4
BESS Installation														
BESS Commissioning														
Interconnection Agreement Navy/Utility														
BESS Online ISO-NE Regulation Pilot														

Figure 5-10 BESS Installation through Demonstration Schedule

5.5 DATA COLLECTION

The data collected for the MCS/FLS events originates from the C90Plus, F35s and D400. The F35 will provide the real-time information for the monitored circuit breakers. The F35 will also provide detailed records of the measured values, receipt of trip command from the C90Plus and waveform (Oscillography and Data Logger information). It is anticipated that GE will support Ameresco and NAVFAC with the analysis of each event during the Demonstration Phase. Ameresco/NAVFAC will be responsible for retrieving the records and forwarding them to the GE Project Manager.

- Data Collector(s): The GE F35, C90Plus and D400 each log pertinent data. The GE HMI utilizes GE Cimplicity SCADA software. The routine analog data is retrieved from the devices on realtime (every 2-3 seconds) basis and displayed at the HMI. This data can be stored on a scheduled interval in the Historian. Alarm events are logged and stored as they occur. The analog and digital data event log and waveforms are automatically retrieved by the solution and stored in Kepware Server software installed on the physical server hard disk

The Main MCS/FLS HMI Screen provides the Operator with a complete picture of the system. Key Summaries: Fast Load Shed System Status, Load Shed Summary, Load Breaker Status (Open, Local/Remote, Load Values, Shed Priority) and Minimum Load to Maintain (Station Service Load) and Power Source Summary (Utility, GTGs, DGs, and BESS). It also provides the means of assigning Load Shed Priorities, Enabling/Disabling the MCS/FLS, Enabling the inclusion of the BESS in the FLS Calculation, and Displaying an Expected Value of Load to be Shed.

Additional HMI Screens allow the Operator to know the status of the Local/Remote (L/R) switches installed on each breaker. The FLS automatically assigns a zero (0) priority for any breaker that is under Local control. This means that this load is not tripped for a LoU event and that it will continue to be served by the available generation Infeeds.

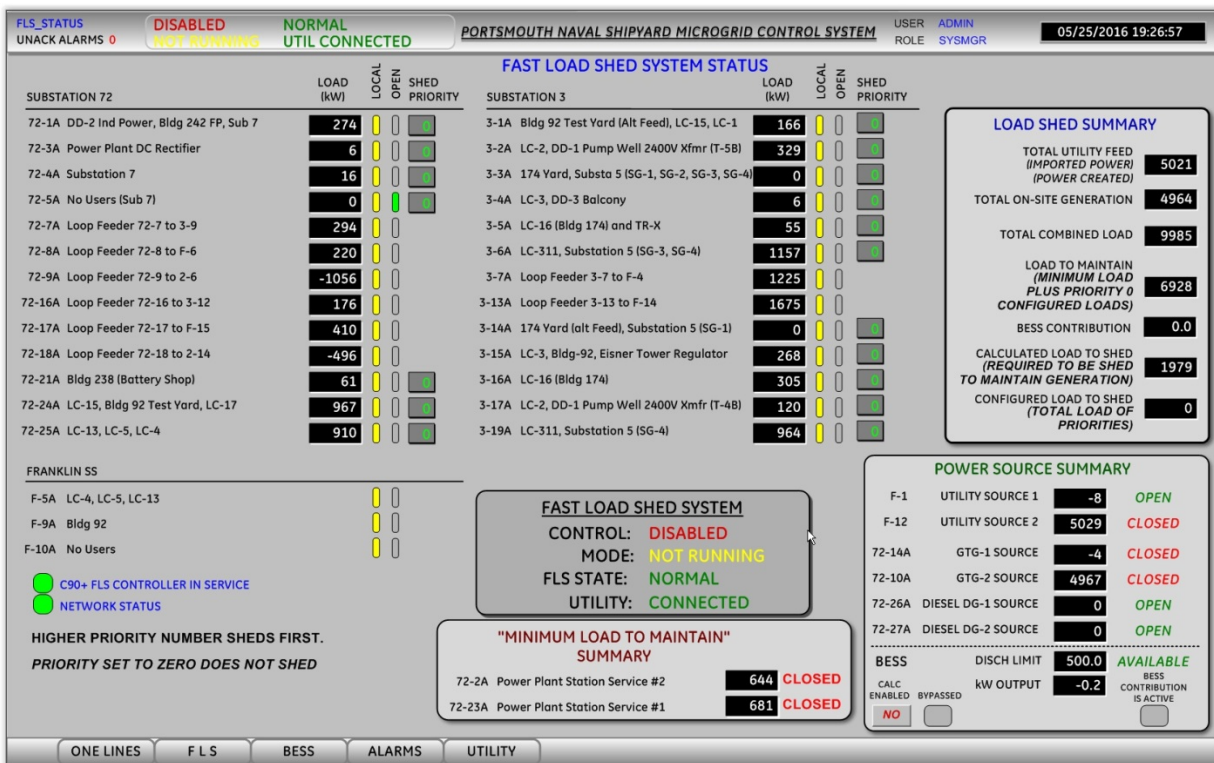


Figure 5-11 Main MCS/FLS HMI Screen

- **Data Recording:** Data recording is automatic in the devices as well as with the Cimplicity HMI/SCADA software.
- **Data Description:** The F35 has flexible settings for data capture. The internal sampling rate for measurements and protection functions is 64 samples per cycle. The oscillography sampling rate is selectable at 8, 16, 32 or 64 samples per cycle. The PNS sampling rate has been set at 32 samples per cycle. The F35 also include a Data Logger can record up 16 channels simultaneously at a sampling rate of 15 to 3600000 ms in steps of 1ms. The Data Logger recorders have finite recorder memory. An example of the memory capability is as follows: 15ms sampling time, 8 analog channels gives 120 seconds of stored data.

Each F35 Controller has a circular event log. These event logs are automatically retrieved by the HMI/SCADA using the GE Integrator software. The data is time stamped and assembled in a time sequence report by the HMI. The Event Logs for the Live Testing are available in Appendix C.

The C90Plus provides a Report (see Figure 5-12 below as an example) for each Fast Load Shed event. This Report provides power values for all Infeeds and Loads at the time of the C90Plus load shed decision point. The report documents which Infeeds were lost, the available generation in the Microgrid Island as well as the minimum amount of Load that was calculated to be shed and the actual amount of Load Shed based upon the assigned Priorities and measured power values.

The C90Plus does allow for a reserve margin for each Infeed to be used to avoid shedding loads, however, PNS Power Operations' made the decision to not depend upon available reserve margin for a LoU event. The primary goal of this demonstration was to keep the Power Plant operational so as to minimize the outage and restoration time. The FLS Reports for the PVT Live Testing can be found in Section 6.

- Data Storage and Backup: The F35 records data per the settings applied. The HMI/SCADA system automatically retrieves data and stores in a Historian. The Dell PowerEdge R720xd server is equipped with a 1 TB HDD. The backup for data would default to NAVFAC defined solutions. We recommend that the data be backed-up on a monthly basis although we do not anticipate that the hard disk capacity will be fully employed during this Project demonstration period.
- Non-standard Data: The Operator Logs will need to be completed after each event. This log can be prepared on the HMI using Excel software and can be printed out for hand written reporting, if necessary. The Operator Event Log is contained in the Performance Verification Test document, which is included in Appendix B.

Relay Data		FLS Report Summary		
Relay Name	C90Plus	Start Date and Time	Oct 16, 2016 12:33:55.727964	
Firmware Version	1.90	Duration	1000 s	
Last Setting Change	Oct 16, 2016 12:43:59	Total Infeed	5093.2 kW	
Calculation Mode	Adaptive	Total Reserve	0.0 kW	
Contingency Time Setting	1000 s	Total Avail Load	5121.0 kW	
Events Enabled	Yes	Total Infeed Lost	1047.5 kW	
		Total Load Shed Requested	1148.6 kW	
		Any FLS Comms Trbl	Yes	
Infeed Designation	Infeed ID	Lost	Power	Reserve
GTG2	IF3	No	4044.7 kW	0.0 kW
GTG1	IF4	No	1.0 kW	0.0 kW
DG-1	IF5	No	0.0 kW	0.0 kW
DG-2	IF6	No	0.0 kW	0.0 kW
SS72-8A	IF7	Yes	143.4 kW	0.0 kW
SS72-9A	IF8	Yes	-962.8 kW	0.0 kW
SS72-17A	IF9	Yes	310.5 kW	0.0 kW
SS72-18A	IF10	Yes	-515.6 kW	0.0 kW
SS3-7A	IF11	Yes	841.5 kW	0.0 kW
SS3-13A	IF12	Yes	1230.5 kW	0.0 kW
BESS	IF32	No	0.0 kW	0.0 kW
Load Group Designation	Load Group ID	Priority	Power	Shed Request
SS72-1A	LG1	2	81.7 kW	No
SS72-2A	LG2	0	274.7 kW	No
SS72-3A	LG3	9	5.1 kW	No
SS72-4A	LG4	5	275.9 kW	No
SS72-5A	LG5	17	0.0 kW	Yes
SS72-7A	LG6	0	0.0 kW	No
SS72-8A	LG7	0	0.0 kW	No
SS72-9A	LG8	0	0.0 kW	No
SS72-16A	LG9	0	0.0 kW	No
SS72-17A	LG10	0	0.0 kW	No
SS72-18A	LG11	0	0.0 kW	No
SS72-21A	LG12	18	60.1 kW	Yes
SS72-23A	LG13	0	748.1 kW	No
SS72-24A	LG14	1	429.1 kW	No
SS72-25A	LG15	16	804.9 kW	Yes
SPARE1	LG16	0	0.0 kW	No
SPARE2	LG17	0	0.0 kW	No
SS3-1A	LG18	3	84.4 kW	No
SS3-2A	LG19	7	240.1 kW	No
SS3-3A	LG20	15	18.3 kW	Yes
SS3-4A	LG21	0	17.3 kW	No
SS3-5A	LG22	14	8.4 kW	Yes
SS3-6A	LG23	4	23.6 kW	No
SS3-7A	LG24	0	0.0 kW	No
SS3-13A	LG25	0	0.0 kW	No
SS3-14A	LG26	11	0.0 kW	No
SS3-15A	LG27	6	1595.9 kW	No
SS3-16A	LG28	12	256.9 kW	Yes
SS3-17A	LG29	8	120.2 kW	No
SS3-19A	LG30	10	76.3 kW	No
SSF-5-9-10	LG31	32	0.0 kW	Yes
	LG32	0	0.0 kW	No

Figure 5-12 Example C90 Plus Report from October 16, 2016 LoU Event

Calibration

- Equipment Calibration: The GE Multilin relays and D400 were tested during their production and were built specifically for the Demonstration. The F35 relays measurement accuracies are: Current: $\pm 0.25\%$ of reading or 0.1% of rated for 0.1 to 2.0 x CT rating; Voltage: 0.5% of reading; and Real Power is $\pm 1.0\%$ of reading. These accuracies are not tested for each device, but sample testing is performed as the design of the devices and selection of components assures better results than in the specification.
- Post-Processing Statistical Analysis: An experienced GE engineer will review the data collected from a LoU event to ensure reasonableness of collected data and to identify possible discrepancies, such as unexpected results from the event. There have been three events since the PVT Testing in December. In each case, the GE engineers have reviewed the system performance and provided feedback to AMERESCO and PNS. See Section 6 for additional details.

Phase II – BESS, Participation in the ISO-NE Regulation Market

The SEL-735 Power Quality and Revenue Meter was built to order specifically for this demonstration by Schweitzer Engineering Laboratories and is shipped with certificate of calibration. This meter is accurate to at least 0.3%.

The D400 will be used to log Modbus communication points over Ethernet so calibration for this device is not applicable.

All other data collection and reporting is performed by ISO-NE and is transmitted to ISO-NE via the DNP3 protocol over a dedicated MPLS network.

These devices were ultimately not utilized for operation in the ISO-NE Pilot program however the SEL-735 did prove to serve as a secondary meter to capture dispatch capacity of the BESS during Phase I.

5.6 DATA RESULTS

Please go to the following appendices to view data results...

APPENDIX B - Performance Verification Test Plan

APPENDIX C – Performance Verification of the Fast Load Shed Solution

APPENDIX D – Event Logs for Live Event Testing of the Fast Load Shed Solution

6.0 PERFORMANCE ASSESSMENT

Refer to Section 3.0 for “Table 1 – Summary of Live Test Results”

Review of Quantitative Performance Objectives

- **Energy Security** - The FLS solution is being applied to assure that the Shipyard generators remain on-line following the tripping of the utility tie breakers. This facilitates the rapid restoration of power to the Shipyard loads and eliminates the disruption of shore power to the boats. The FLS solution provides adaptive tripping by monitoring the power values of the shipyard loads, shipyard generation (infeeds) and utility power (lost infeed). Following the LoU event, the Operator will document which generators were online and whether they remained online following the FLS tripping of loads.
- **Proficiency of MCS to Maintain Generation – Load Balance for Loss of Utility** - The data captured by solution for a Loss of Utility event is time stamped (microsecond accuracy) and stored in the HMI Historian. More extensive time stamped data for each load and source is captured and stored in the F35s and C90Plus. This device data can be retrieved and stored at the HMI server. The operator will capture a post event screenshot of the HMI display to provide a complete record of the breakers tripped and generation and load values.

The data stored on the HMI server will be reviewed following an event and summarized in a form that lists the pre/post-event power data for all infeeds, each load circuit, the shed Priority of each load, and the C90Plus list of loads shed. This table will indicate which loads the HMI show as tripped and their priority. This allow for a comparison of the actual load shed versus based upon priority versus the pre LoU event. It will also provide a documented record of the post-event status of the Shipyard power system. The analysis of the data will be done Post-event by the PI, GE engineer and NAVFAC personnel to verify that the C90Plus tripped the proper amount of load to maintain the generation-load balance.

- **Demonstration of Fast Load Shedding** – The post event analysis will include the evaluation of the timing of the events as well as the waveforms and the operation of the monitored point within the C90Plus and the F35 feeder controllers. This data will be presented in a tabular format and any deviations from expected operational times will be noted.
- **Annual Avoided Cost of Lost Production** – The PI will establish the length of each outage. The PI will work with Shipyard Operations to establish an estimated hourly cost. And the size of the loads (MW) lost versus saved. This data will allow for the calculation of a yearly cost, or Annual Avoided Cost, for Loss of Utility Events. The Total Cost of the FLS can then be divided by the Annual Avoided Cost to establish a simple payback in years.

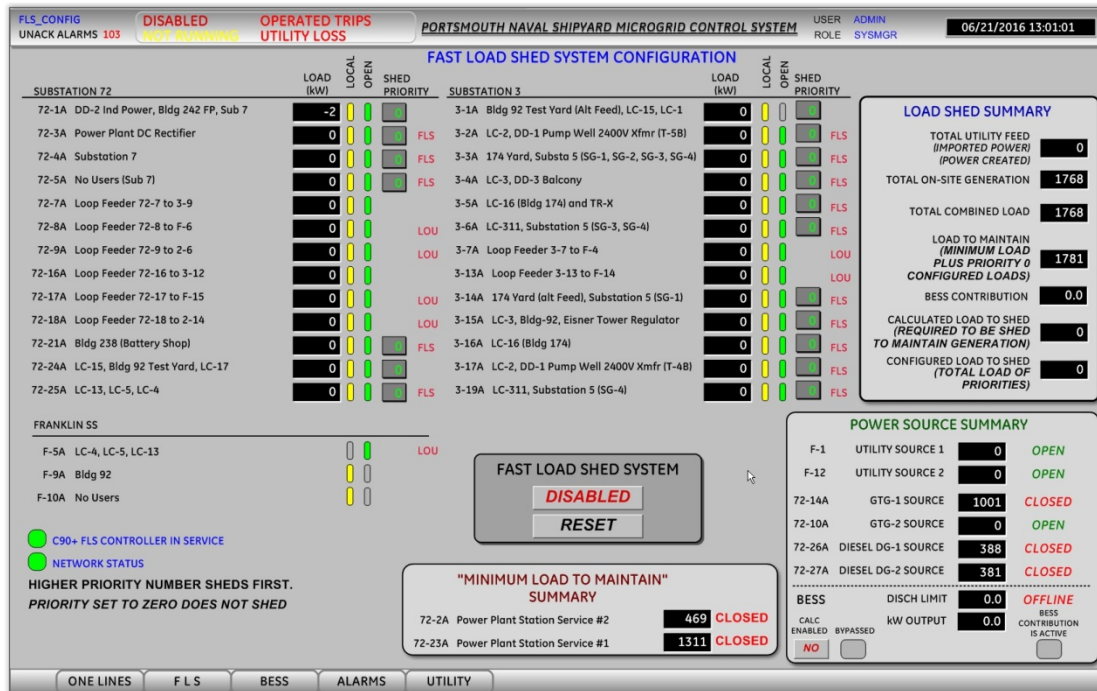


Figure 6-1 Example of HMI Screenshot – Post Event Analysis

- BESS Participation in Transition to Island Mode** – The BESS can provide up to 1 MW of additional power to serve the Shipyard loads. The D400 will monitor the BESS site controller and provide current BESS power values (-500kW to +500kW) to the C90Plus for inclusion in the power balance calculation. Upon detection of the LoU event, the D400 will initiate the Microgrid control of the BESS to go to full kW output. This output will be maintained until the Diesel Generators are available to pick up load, acting as a “Bridge” until the back-up generation comes online. At that time, the BESS site controller will revert to normal operation mode.

* Ultimately we were unsuccessful in getting the GE C90 to properly include this capacity in its calculation. Additional programming and tests would need to be performed to verify if this function is viable.

Review of Qualitative Performance Objectives

Ease of Use - will be demonstrated by the Operators ease in learning the system, the understanding of the HMI screens, the regular updates of the Load Shed Priority and use of the HMI system in aiding the Operator in the manual restoration of loads that were shed by the MCS/FLS.

Operational value of MCS/FLS – will be determined by the successful demonstration of the MCS/FLS and the experience of NAVFAC management, Operators, and Technicians.

External Validity - Transferability of MCS-FLS application to other DoD sites – will convey the likelihood that the demonstration can be repeated with success at other installations.

Performance Verification Testing (PVT)

Please refer to Appendix C for the complete reports.

GE Microgrid Fast Load Shed Operation - The MCS continually monitored the PNS incoming utility breakers located in Franklin Substation for an islanded condition. An island condition was detected by the new F35 relays based upon tripping of the utility tie breakers by the existing utility under/over-voltage and under/over-frequency protective relays. When an island condition was detected, appropriate IEC 61850 Generic Object Oriented Substation Events (GOOSE) messages were sent to the MCS. When the PNS power system islanded from the main power grid the MCS completed the following actions (the priority of load shedding “candidates” is pre-configured):

Table 6-1 Operational Steps to Island

Step #	Step Description	Notes
1	Loss of utility; F1 and F12 at Franklin Substation trip and/or under-frequency detected at Power Plant (PP)	
2	Main substation controller sends trip messages to feeder controllers	Using IEC 61850 GOOSE messaging
3a	PP substation breakers 8, 9, 17 and 18 tripped by fast load shedding logic in main substation controller	Separates PP from Franklin Substation and Substation 2
3b	Feeder controllers trip Substation 3 breakers 7 & 13	Separates Substation 3 from Franklin Substation
3c	Power Plant feeder controllers trip appropriate load feeders to balance available generation	Depending on the output of the GTGs, station power requirements, and loads current being served
3d	Substation 3 feeder controllers trip appropriate load feeders to balance available generation	Same as 3c
3e	Franklin Substation feeder controller trips breakers 5, 9 and 10	Prevent back feeds through load centers
4	BESS Site Controller turns control of BESS over to D400 to charge or discharge real power to help balance available generation	C90Plus initiates Mode change in BESS Site Controller.
5	NAVFAC personnel initiate sequence to bring further generating units on-line and adjusting BESS output	Diesel Generators are automatically started and synchronized by DCS
6	NAVFAC personnel close breakers to pick-up additional critical loads	

To complete steps 3c, 3d, and 3e above, the MCS had up to 30 pre-defined load shedding tiers with corresponding priorities. The total power shed will be calculated from the instantaneous power loads recorded by GOOSE messages from the UR F35 relays just before the islanding event.

Simulated Testing

The first phase of the Demonstration of this system was performed by Simulated Testing (SIM Test) on December 3, 2015. Two tests of the FLS were conducted by varying the output of the PNS Gas Turbine Generators. The SIM Testing consisted of simulating the open of the Utility tie breakers and allowing the FLS to initiate breaker tripping actions per the above sequence. PNS Power Operations cutout the trip circuits by the opening of the trip test switches for each F35 relay. The detection of the Loss of Utility (closure of the Breaker F1 & F12 'b' switches) was simulated by placing a jumper across the appropriate input terminals of F-F35-1 at Franklin Substation. The trip outputs of the F35 relays at the Power Plant, Substation 3 and Franklin Substation were not disabled for the SIM Test so as to provide indication that F35 relays did attempt to trip the appropriate breakers. However, the trip outputs were not connected to the actual trip coils of the 13.2kV breakers.

The first control action initiated by the C90Plus for a Loss of Utility event is to create a power island consisting of the Power Plant and Substation 3. This command is communicated to the F35 controllers by sending a GOOSE message to two (72-F35-2 & 72-F35-3) of the four F35 relays at the Power Plant and a single F35 relay (3-F35-2) at Substation 3. Each relay trips two loop feeders. This includes the two loop feeders that tie the Power Plant to Franklin Substation and the two loop feeders that tie the Power plant to Substation 2 (Step 3a), and the two loop feeders that tie Substation 3 to Franklin Substation (Step 3b). The single F35 at Franklin also tripped three load breakers (Step 3e). These breakers have the potential to be backfed from Substation 3 and the Power Plant.

Steps 3a, 3b and 3e occurred for both Simulated Tests. These actions resulted in complete loss of service to the Substation 2 and Franklin loads.

The Loss of Utility message is received by the C90Plus Fast Load Shed (FLS) device which continuously calculates the generation-load imbalance for the Power Plant/Substation 3 island. For Simulated Test #1 and #2, the C90Plus initiated tripping via GOOSE message (Step 3c & 3d) of the load breakers at Substation 3 and the Power Plant based upon the Load Priority Schedule established by PNS. Each F35 received the message and took action to trip the appropriate load breakers.

The BESS is operated during this testing as well and was tested in two operating conditions "Buffer" and "Bridge".

- a. In "Buffer" mode: The unit is dispatched at the time of disconnection from the utility (operation of the FLS), but its capacity was not taken into account with the load shed calculations (referred to as "Buffer" mode). Thus the capacity of the BESS served as an additional 500kW "Buffer", where the FLS maintained critical loads to match the available capacity of the Gas Turbine Generators only. For initial testing the focus of the BESS was to confirm successful dispatch of the unit, but not to allow the FLS to take the additional generation capacity into consideration within the load shed calculations.

This was deemed a prudent approach to first confirm the programming to dispatch the BESS was functional.

- b. In “Bridge” mode: The BESS was tested during a later PVT with the additional 500kW capacity of the battery taken into account with the load shed calculations. In this mode the BESS operates at full discharge, holding additional critical loads, until the emergency diesel generators come on-line, at which time the loads being held by the BESS are transferred to the generators; effectively acting as a “Bridge”.

In both the “Buffer” and “Bridge” operating modes the BESS dispatches and continues to put out a max discharge of 500kW until the emergency diesel generators come on-line. The “Bridge” mode was not tested during the demonstration, due to the inability to get the GE C90 to include the available battery storage in its calculations.

It should be noted that a Table was developed for logging of the Pre-FLS Test conditions by Ameresco, GE and key NAVFAC personnel, see Table 6-1 below as an example. A complete set of tables can be found in Appendix C.

Table 6-2 FLS Performance Verification Test Example

Portsmouth Naval Shipyard									
Fast Load Shed System (FLS) Performance Verification Test									
Scenario		Summer - CTG#1 **CTG#2 was running to provided Steam							
Test Date		12/3/2015 15:16:23						Sim X	
Test No.		1 of 2						Live _____	
Fast Load Shed Test Configuration									
Priority	Breaker	Actual Load	Total Load	Shed (Y / N)	HMI (Y / N)	Relay (Y / N)	Source	Actual Load	Opn / Cls Status
32	F-10	Insert Total from Sub 2 Calc or Alt Sub 2 Loop Calc 4179		Y	Y	Y	UTILITY-1	5846	
32	F-9			Y	Y	Y	UTILITY-2	0	
32	F-5			Y	Y	Y	GTG-1	4701	
32	72-18a			Y	Y	Y	GTG-2**	461	
32	72-9a			Y	Y	Y	DG-1	0	
32	72-17a			Y	Y	Y	DG-2	0	
32	72-8a			Y	Y	Y	BESS	0	
32	3-7a			Y	Y	Y	Total Gen	5162	
32	3-13a	Y	Y	Y					
18	72-21a	88	88	Y	Y	Y			
17	72-5a	0	88	Y	Y	Y			
16	72-25a	1230	1318	Y	Y	Y			
15	3-6a	494	1812	Y	Y	Y			
14	3-19a	0	1812						
13	72-4a	7	1819						
12	3-14a	5	1824						
11	3-16a	337	2161						
10	3-5a	49	2210						
9	72-3a	5	2215						
8	3-17a	60	2275						
7	3-2a	514	2789						
6	3-15a	549	3338						
5	3-4a	7	3345						
4	3-3a	155	3500						
3	3-1a	172	3672						
2	72-1a	128	3800						
1	72-24a	1725	5525						
0	72-16a	-96	Do Not Add						
0	72-7a	-119	Do Not Add						
0	72-23a	91							
0	72-2a	1287							
Total Load		11082							

Sub 2/Franklin	
2-1	
2-2	
2-4	
2-5	
2-10	
2-16	
2-17	
F-10	
F-9	
F-5	
Total	

Alt Sub 2/Franklin	
F1/F12	5846
Subtract	
PP <-> Sub 2 72-18a	-605
PP <-> Sub 2 72-9a	-1017
PP <-> Frank 72-17a	332
PP <-> Frank 72-8a	404
Sub 2 <-> Frank 3-7a	1428
Sub 2 <-> Frank 3-13a	1125
Total	4179

NAVFAC	_____
AMERESCO	_____
GE	_____

Load to Shed =	PP/Sub3 Infeeds	1667

This Table, along with a few quick math calculations, allowed the Test participants to predict which breakers should be tripped for each scenario. In both tests, the C90Plus attempted to shed the correct amount of load required to maintain the balance of generation and load for the Power Plant/Substation 3 island.

The Tables for each Test as well as the screen shots of the HMI Pre-Test and Post Test Conditions can be found in Appendix C. The values from the Pre-Test were used to fill-out the Table. The calculation of the PP/Sub3 Infeeds determines the amount of Priority Load to be shed. If this value is positive, then successive Priority loads are accumulated until the “Total Load” is greater than the PP/Sub3 Infeed (see center column of the Table). If the PP/Sub 3 Infeeds is negative, then this indicates that there will be surplus of power available after the Power Plant/Substation 3 power island is formed and none of the loads in the island will need to be shed.

Please note that the specific value of the load shed ultimately is determined by the actual loads at the time a Loss of Utility event occurs and the trip priorities in effect at the time that the C90Plus locks in its’ calculation and establishes the load to be shed. Any variation in the Island loads is accounted for by changes in the Utility Infeed as the Shipyard DCS acts to maintain relatively constant power output when connected to the Utility. This variation in loads was observed during the PVT and made it challenging to log the values into the Table. The use of the HMI screen shots facilitated this effort, also found in Appendix C.

It should also be noted that due to the defined limitations of the demonstration, the loads at Franklin and Substation 2 will always be tripped. The Table allows for the calculation of the total value of the Load that will be lost. The preparation for the PVT led to discussion of whether there was a method to include this calculated load in the C90Plus calculations. The use of IEC61850 GOOSE messaging as implemented does not allow for this type of calculation. The future addition of F35 controllers at Substation 2 and Franklin is required. This led to the Shipyard establishing operational procedures whereby they will disable the FLS should the net of utility supplied power be nearly zero or negative. The condition can occur when bad weather is forecast and the probability increases that the utility tie will be lost.

Simulated Test #1

For Simulated Test #1, NAVFAC decided to perform this test with both GTGs running. GTG#1 was loaded to close to its’ nameplate rating and GTG#2 was loaded at ~10% of its’ nameplate rating. This was a preventative measure should GTG#1 trip off for an unanticipated reason thus assuring at least one GTG would be available to support the Shipyard. The C90Plus FLS Load Shed Order of 1,596kW (see lower left corner of SIM Test #1-Post Test HMI Screen) was required to offset the Utility power that was lost as an Infeed to the Island. This compares favorably to the 1,667 kW calculated for PP/Sub3 Infeeds as shown in Table - SIM Test #1. The actual load to be shed was calculated to be 1,812 kW as shown on the SIM Test #1 Table. This demonstrates the variability of the Shipyard loading.

The FLS did issue shed commands to load breakers 72-21a, 72-5a, 72-25a and 3-6a as shown on the HMI screen and was verified by the Substation personnel located at each Substation. This was as predicted in the Table.

The BESS was not operated during the first simulation.

Simulated Test #2

For Simulated Test #2, the calculations in the Table predicted that none of the Priority loads in the power island would have to be shed. The C90Plus determined that the loss of the Infeed from the Utility did not require any further load shedding in the power island once the load supplied at Substation 2 and Franklin was tripped off. The total load to be shed at these substations was calculated using FLS measured values at 4,296 kW. The FLS System performed exactly as designed.

The Simulated Tests demonstrated that the FLS was able to calculate the proper generation-load balance for the two key Scenarios. This assured PNS Power Operations that the FLS was properly configured and PNS Navy personnel gave the go ahead for Live Testing of the FLS.

The BESS was activated during this test but initially failed to operate. An error in the program was identified, the error was corrected and a second Test #2 was ran with the BESS successfully dispatching.

Live Testing

Live Testing of the FLS was conducted on December 8. The Scenarios tested were essentially the same as those in the Simulated Tests. There were three key purposes of the Live Testing: 1) verify that the Power Plant does not trip off for a Loss of Utility event, 2) verify that the FLS could detect the loss of utility and initiate tripping of the appropriate breakers within 20 milliseconds (ms) and that the overall clearing time was less than 80 ms from detection of the Loss of Utility and 3) verify the capability of the GTGs to continue to support the Shipyard. The original expectation was that the overall clearing time would be less than 140 ms. Subsequently, this was reduced to 80 ms. The verification of the GTG performance was done to establish their ability to function for these scenarios.

Live Test #1

The Summer Scenario was tested first. The Pre-Test data is included in the attached Scenario 1 Table and Pre-Test HMI Screen. The Post-Test data is as shown in the Post-Test HMI Screen. The same loads that were tripped in Simulated Test #1 were once again tripped in the Live Test. The Power Plant stayed on-line and the Diesel-Generators started up and synchronized to support the load restoration. Following the collection of data and verification that each breaker did trip, PNS Operations restored the connection to the Utility and restored power to all tripped loads. The FLS was placed out-of-service during the restoration process. The Test Team then moved on to perform Live Test #2.

Live Test #2

The Winter Scenario was then tested. GTG#2 was started and synchronized on-line with GTG#1. The DCS adjusted the power supplied by the GTGs such that the Utility tie supply was reduced from 5 MW in Test #1 to less than 1 MW. The combined output of the GTGs was clearly sufficient (see Live Test #2 Table) to supply all load in the Power Plant/Substation 3 island.

Demonstration Period Events

February 16, 2016 FLS Event -Subsequent to the Simulated and Live Testing, an unexpected FLS event (load was shed) occurred on February 16, 2016 when one of the Diesel Generators was manually shut down by the Power Plant Operators during a routine cycling. The data collected by the FLS equipment allowed for the quick identification of the cause of the FLS trip. The settings implemented in the C90Plus had incorrectly been set to allow FLS to occur for the tripping of the DG.

The settings were corrected and the FLS was re-tested on March 30, 2016 to verify that the C90Plus would not initiate a Fast Load Shed for this scenario. The Shipyard chose to conduct additional verification testing at that time to assure that the tripping of any of the six loop feeders (the ties between the Power Plant and Substation 2/Franklin and Substation 3 and Franklin) would not result in a FLS event. This testing verified that these normal tripping events would not result in the FLS causing load to be shed. In other words, the security of the scheme was verified. The FLS was placed back into service on March 31.

June 16, 2016 FLS Event - On June 16, 2016, the 34.5kV feeder that supplies PNS with utility power experienced a flashover of a line switch. This caused a Loss of Utility event to be detected by the MCS/FLS and the solution acted to shed load. The Shipyard was operating under Summer Load conditions and only GTG#2 was online. A protective relay for this unit detected a failure and caused the sole power source to be tripped off just prior to the FLS acting to shed the necessary loads to keep this unit online. The subsequent analysis of the data collected by PNS revealed that the FLS had shed the correct amount of load and that the Power Plant would have stayed online absent the tripping of the GTG. An unrecognized issue arose with the initiation of waveform capture in each of the F35 Controllers and the capturing of this data at the HMI. The settings in the F35 relays were updated the week of August 22 to remedy this issue. The HMI server was originally to be installed in a GE furnished cabinet with a 4 hour UPS. It was decided to install the server in the Power Plant Operators' control room. The HMI server was not connected to the control room UPS. This connection has been remedied.

July 18, 2016 FLS Event - PNS experienced another LoU event on the morning of July 18. The FLS operated as expected, saving a substantial portion of critical operations on the yard. Coincidentally, the Power Plant Operators were exercising the DGs when the event took place, so in addition to GTG#1 being online, there was also an additional 1.5MW of capacity of emergency generation accounted for by the FLS. Since the DGs were online, the BESS discharge/support was not activated in accordance with the D400 control design.

The issue with the initiation of the waveform retrieval by the HMI remained. As a result, the capture of waveforms for the Power Plant and Substation F35 controllers did not occur. Fortunately, the Franklin F35 did capture the event. A review of the waveforms from the F35 at Franklin Substation was conducted by GE and they revealed that a phase-to-phase fault occurred on the Utility feeder. The fault lasted for about 630ms. The FLS acted to trip the loop feeders and create the power island. Breakers 5, 10 and 11 at Franklin Substation were also tripped as per the design. The FLS preserved the power island by tripping a total of 1,544.9kW of load being served by breakers 72-21A and 72-25A (both at the Power Plant). PNS started GTG#2 and began to pickup additional load and the Utility tie was finally restored 2-1/2 hours after the initiation of the LoU event. The C90Plus Load Shed Summary is attached along with the waveforms from the Franklin F35.

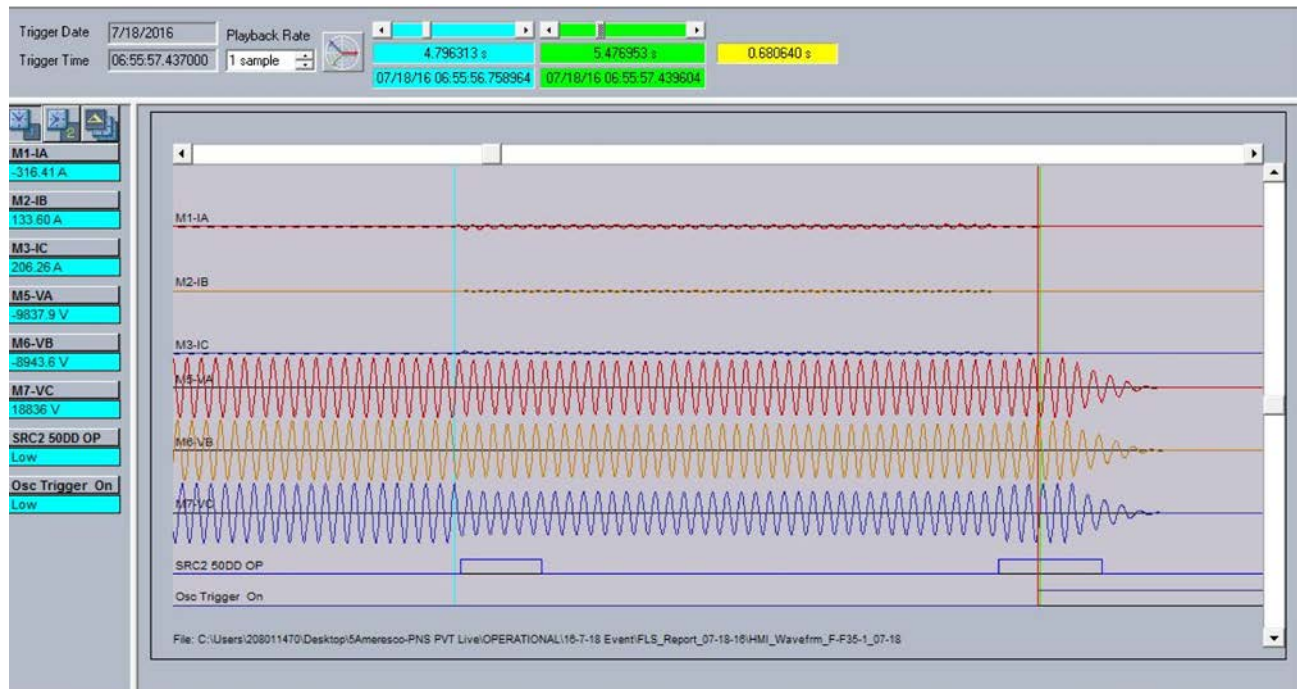


Figure 6-2 F-F35-1 Waveform Capture of July 18, 2016 Loss of Utility Event

The HMI was pre-configured to retrieve data from the Historian and provide an extended display of the Power Plant performance during a Loss of Utility Event. The following System Event display was captured by the PNS Operators for the July 18 Event.

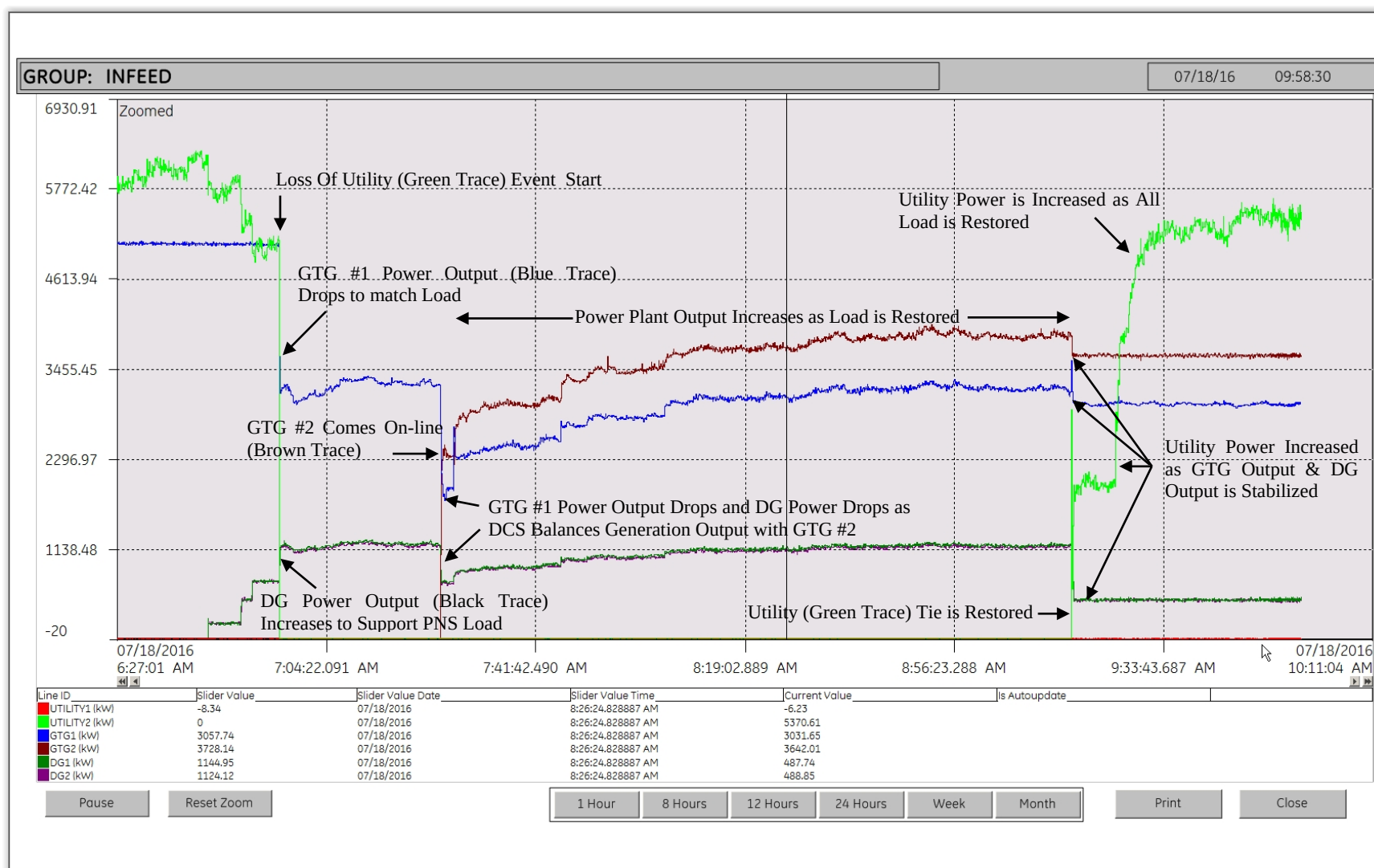


Figure 6-3 HMI Trend Display – July 18

PNS started GTG#2 and began to pick up additional load. The Utility tie was finally restored 2-1/2 hours after the initiation of the LoU event. The C90Plus Load Shed Summary is shown below.

Relay Data		FLS Report Summary		
Relay Name	C90Plus	Start Date and Time	Jul 18, 2016 05:56:24.773032	
Firmware Version	1.90	Duration	368 s	
Last Setting Change	Jul 08, 2016 06:10:53	Total Infeed	7533.6 kW	
Calculation Mode	Adaptive	Total Reserve	0.0 kW	
Contingency Time Setting	1000 s	Total Avail Load	7692.6 kW	
Events Enabled	Yes	Total Infeed Lost	1010.1 kW	
		Total Load Shed Requested	1544.9 kW	
		Any FLS Comms Trbl	Yes	
Infeed Designation	Infeed ID	Lost	Power	Reserve
GTG2	IF3	No	0.1 kW	0.0 kW
GTG1	IF4	No	5009.2 kW	0.0 kW
DG-1	IF5	No	738.5 kW	0.0 kW
DG-2	IF6	No	725.7 kW	0.0 kW
SS72-8A	IF7	Yes	272.8 kW	0.0 kW
SS72-9A	IF8	Yes	-1378.6 kW	0.0 kW
SS72-17A	IF9	Yes	372.0 kW	0.0 kW
SS72-18A	IF10	Yes	-807.8 kW	0.0 kW
SS3-7A	IF11	Yes	1035.6 kW	0.0 kW
SS3-13A	IF12	Yes	1516.1 kW	0.0 kW
BESS	IF32	No	0.0 kW	0.0 kW
Load Group Designation	Load Group ID	Priority	Power	Shed Request
SS72-1A	LG1	2	439.0 kW	No
SS72-2A	LG2	6	730.0 kW	No
SS72-3A	LG3	9	5.2 kW	No
SS72-4A	LG4	5	232.7 kW	No
SS72-5A	LG5	17	0.0 kW	Yes
SS72-7A	LG6	0	0.0 kW	No
SS72-8A	LG7	0	0.0 kW	No
SS72-9A	LG8	0	0.0 kW	No
SS72-16A	LG9	0	0.0 kW	No
SS72-17A	LG10	0	0.0 kW	No
SS72-18A	LG11	0	0.0 kW	No
SS72-21A	LG12	18	104.1 kW	Yes
SS72-23A	LG13	0	751.9 kW	No
SS72-24A	LG14	1	1146.9 kW	No
SS72-25A	LG15	16	1440.8 kW	Yes
SPARE1	LG16	0	0.0 kW	No
SPARE2	LG17	0	0.0 kW	No
SS3-1A	LG18	3	178.3 kW	No
SS3-2A	LG19	7	236.5 kW	No
SS3-3A	LG20	15	12.5 kW	No
SS3-4A	LG21	13	19.4 kW	No
SS3-5A	LG22	14	57.6 kW	No
SS3-6A	LG23	4	18.2 kW	No
SS3-7A	LG24	0	0.0 kW	No
SS3-13A	LG25	0	0.0 kW	No
SS3-14A	LG26	11	147.8 kW	No
SS3-15A	LG27	6	1265.9 kW	No
SS3-16A	LG28	12	438.6 kW	No
SS3-17A	LG29	8	320.5 kW	No
SS3-19A	LG30	10	146.9 kW	No
SSF-5-9-10	LG31	32	0.0 kW	Yes
	LG32	0	0.0 kW	No

Figure 6-4 C90 Plus Load Shed Report – July 18, 2016 LoU Event

October 16, 2016 FLS Event - PNS experienced another LoU event on the afternoon of Sunday, October 16. The FLS operated as expected, however, the Fault was an extended time event resulting in the Tripping of the operating GTG before the FLS could act. This event was evaluated by PNS Power Operations and brought home the need to add a Fast Transfer Trip signal when the Utility breaker trips.

The F-F35-1 Controller at Franklin captured the complete event as shown in this waveform. The Fault Event lasted for over 0.9 seconds. The waveform shows the extended amount of power (SRC 2 P) that flowed into the fault from the PNS System. This waveform also shows the FLS Load Shedding being initiated (F-5 LS Req On) 129 ms after the Franklin breaker had cleared the fault.

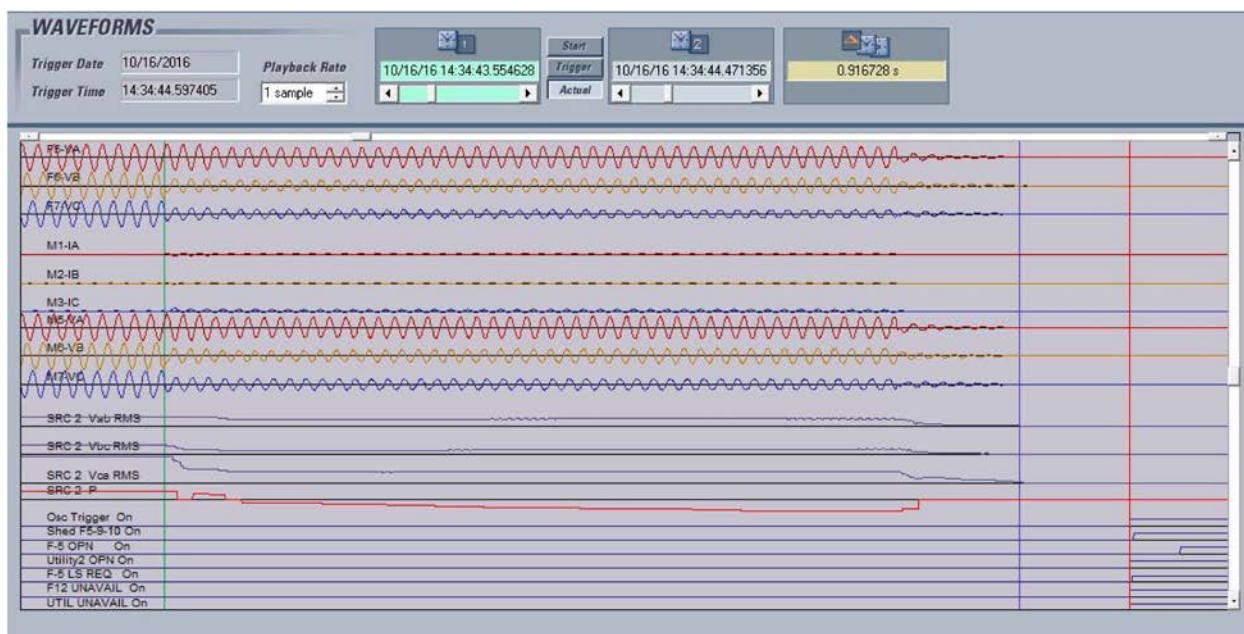


Figure 6-5 F-F35-1 Waveform and Event Capture – October 16, 2016 LoU Event

The Power Plant Controller, 72-F35-2, captured the waveforms and events associated with tripping two Loop Feeders (72-8A and 72-9A) as well as trip of GTG #2. The following waveform shows that GTG #2 tripped 805 milliseconds after the initiation of the fault on the CMP Feeder. It also shows the FLS initiating the Trip of the Loop Feeders 242 ms (delta time between Blue line and Red Line). The Plant DCS acted to trip GTG #2. If this had not occurred, the FLS would have acted to maintain the steady state generation load balance.

The FLS acted to trip the loop feeders and create the power island. Breakers 5, 10 and 11 at Franklin Substation were also tripped as per the design. The FLS acted to preserve the power island by tripping the Loop Feeder breakers. The C90Plus calculated that 1,047.5kW would need to be shed and issued a Load Shed Request for 1,148.6 kW. The C90Plus initiated shedding of load breakers 72-5A, 72-21A, 72-25A, 3-3A, 3-5A and 3-16A. The C90Plus Load Shed Summary is provided below.



Figure 6-6 F-F35-1 Waveform and Event Capture – October 16, 2016 LoU Event

Relay Data		FLS Report Summary		
Relay Name	C90Plus	Start Date and Time	Oct 16, 2016 12:33:55.727964	
Firmware Version	1.90	Duration	1000 s	
Last Setting Change	Oct 16, 2016 12:43:59	Total Infeed	5093.2 kW	
Calculation Mode	Adaptive	Total Reserve	0.0 kW	
Contingency Time Setting	1000 s	Total Avail Load	5121.0 kW	
Events Enabled	Yes	Total Infeed Lost	1047.5 kW	
		Total Load Shed Requested	1148.6 kW	
		Any FLS Comms Trbl	Yes	
Infeed Designation	Infeed ID	Lost	Power	Reserve
GTG2	IF3	No	4044.7 kW	0.0 kW
GTG1	IF4	No	1.0 kW	0.0 kW
DG-1	IF5	No	0.0 kW	0.0 kW
DG-2	IF6	No	0.0 kW	0.0 kW
SS72-8A	IF7	Yes	143.4 kW	0.0 kW
SS72-9A	IF8	Yes	-962.8 kW	0.0 kW
SS72-17A	IF9	Yes	310.5 kW	0.0 kW
SS72-18A	IF10	Yes	-515.6 kW	0.0 kW
SS3-7A	IF11	Yes	841.5 kW	0.0 kW
SS3-13A	IF12	Yes	1230.5 kW	0.0 kW
BESS	IF32	No	0.0 kW	0.0 kW
Load Group Designation	Load Group ID	Priority	Power	Shed Request
SS72-1A	LG1	2	81.7 kW	No
SS72-2A	LG2	0	274.7 kW	No
SS72-3A	LG3	9	5.1 kW	No
SS72-4A	LG4	5	275.9 kW	No
SS72-5A	LG5	17	0.0 kW	Yes
SS72-7A	LG6	0	0.0 kW	No
SS72-8A	LG7	0	0.0 kW	No
SS72-9A	LG8	0	0.0 kW	No
SS72-16A	LG9	0	0.0 kW	No
SS72-17A	LG10	0	0.0 kW	No
SS72-18A	LG11	0	0.0 kW	No
SS72-21A	LG12	18	60.1 kW	Yes
SS72-23A	LG13	0	748.1 kW	No
SS72-24A	LG14	1	429.1 kW	No
SS72-25A	LG15	16	804.9 kW	Yes
SPARE1	LG16	0	0.0 kW	No
SPARE2	LG17	0	0.0 kW	No
SS3-1A	LG18	3	84.4 kW	No
SS3-2A	LG19	7	240.1 kW	No
SS3-3A	LG20	15	18.3 kW	Yes
SS3-4A	LG21	0	17.3 kW	No
SS3-5A	LG22	14	8.4 kW	Yes
SS3-6A	LG23	4	23.6 kW	No
SS3-7A	LG24	0	0.0 kW	No
SS3-13A	LG25	0	0.0 kW	No
SS3-14A	LG26	11	0.0 kW	No
SS3-15A	LG27	6	1595.9 kW	No
SS3-16A	LG28	12	256.9 kW	Yes
SS3-17A	LG29	8	120.2 kW	No
SS3-19A	LG30	10	76.3 kW	No
SSF-5-9-10	LG31	32	0.0 kW	Yes
	LG32	0	0.0 kW	No

Figure 6-7 C90 Plus Load Shed Report – October 16, 2016 LoU Event

Results for Quantitative Performance Objectives

Energy Security - The SIM Tests and the Live Tests met the performance requirements by successfully islanding the Shipyard. The MCS Fast Load Shed tripped sufficient load to keep the Gas Turbine Generators on-line and maintain a steady state generation – load balance.

Proficiency of MCS to Maintain Generation – Load Balance for Loss of Utility – As expected, the FLS performed flawlessly once the settings were established for the Shipyard. The existence of the multiple Loop feeders at PNS provides a high level of power reliability as more than one loop can trip without any loss of load. However, this configuration required unique settings and control for the C90Plus. The detection of the Loss of Utility was done by monitoring the tripping of the Utility Tie breakers. This is the standard practice at existing installations of the C90Plus.

Normally, the amount of utility power lost would be a key factor in determining which priority loads to shed. In this demonstration the power level supplied by the utility is monitored by the MCS/FLS to provide a complete picture of the PNS system. However, the measurement of the power flows on the Loop feeders tied to the Power Plant and Substation 3 became the key power measurement used to establish which priority loads would be tripped. Further, the MCS/FLS had to trip the Loop feeders to isolate the power island. The ability of the MCS/FLS to accommodate this design demonstrated the flexibility of this technology. The potential for expansion of the MCS/FLS to include Substation 2 and Franklin in the FLS calculations will, in fact, simplify the operation of the scheme and reduce the tripping duty on the Loop feeder breakers.

Demonstration of Fast Load Shedding - The MCS FLS performance surpassed the expected performance criteria. The existing F1 utility tie breaker did not have a spare ‘b’ contact available to indicate the Loss of Utility. The design added an auxiliary relay into the ‘b’ contact circuit. This aux relay added a two cycle delay in the detection of Loss of Utility. The FLS acted to issue Shed commands in 3 milli-seconds and the Shipyard was islanded and load shed within 32 to 40 ms of detecting the Loss of Utility. Overall trip time, including the two cycle delay was a maximum of 72 ms. Please refer to Appendix D for the waveforms from Live Test #1.

Annual Avoided Cost of Lost Production - The calculation of the avoided cost requires 1) historical average of the number of outages, 2) average length of the outages and 3) hourly value of lost production. The Shipyard experienced three live events over the demonstration period. Through interview of PWD staff and experience on-site since 2001 we understand the length of outages to be in the range of 30 minutes to 2 hours. The restoration of the Shipyard following each the Live Test was accomplished within one hour. This included time to collect records, verify all substation breakers were in Local Control, loads restored and then re-synchronize to the Utility. See Section 7.0 for further calculations and results.

BESS Participation in Transition to Island Mode - The control of the BESS by the D400 (Steps 4 & 5) was tested in a separate Simulation Test that essentially duplicated a Summer scenario where one GTG was online. The C90Plus initiated the mode change to Microgrid operation and the D400 directed the BESS to ramp up at its’ maximum rate to discharge 500kW. The response time for this change was less than 0.5 seconds. This included a 200 ms delay for the BESS Controller to change operation mode to Microgrid Dispatch, another 200 ms for the BESS Controller to execute the D400 commands and 16 ms for the BESS to achieve maximum output. The approximate overall time to achieve maximum BESS discharge output is 416 ms.

The Power Plant DCS detects a Loss of Utility (LoU) in through a separate detection circuit. Following the LoU, the DCS initiates the automatic start-up and synchronization of the two 1.5 MW Diesel Generators. The MCS detects that the Diesel-Generators have come on-line by monitoring the status of their circuit breakers. The D400 then commanded the BESS to reduce output to zero at a gradual rate of change. This allowed the D-Gs to pick-up the load that the BESS was supporting. The BESS Site Controller then returned to its' previous mode of operation.

Another portion of this performance objective was related to participating in the Avoided Cost of Lost Production. The plan was to capture and analyze value of the BESS saving additional loads above what could be carried by the CGTs during an FLS event. This is the function previously noted as a "bridge" where the BESS would hold load until the emergency generators came on-line. Ultimately, we were unsuccessful in getting the GE C90 to properly include this capacity in its calculation. Additional programming and tests would need to be performed to verify if this function is viable to count towards further savings in avoided production costs.

Results for Qualitative Performance Objectives

Ease of Use – The Power Plant Operators have been provided hands-on training in their interface with the MCS/FLS. The HMI screens have undergone a number of changes as the Shipyard has gained experience. Overall, the NAVFAC personnel have come to appreciate the capabilities of the MCS/FLS and have instituted and adjusted the necessary operational controls and procedures. The changes in the HMI have come about as the operators have become more familiar with the system and have requested the simplification and reduction in the number of steps required to enable/disable the system and to shorten these processes.

Operational Value of MCS/FLS – The NAVFAC Power Operation management have become key supporters of this solution and they fully appreciate the fact that they do not have to experience a shutdown/trip of the GTGs following a Loss of Utility event. They have expressed their satisfaction with the solution by moving ahead with the addition of a remote viewer at the Power Operations Building and they have begun to discuss their plans to expand the solution to cover Franklin Substation and Substation 2. NAVFAC personnel also recognize that the F35 Controllers have the capability to provide protection functions that would replace the existing solid state relays.

Transferability of MCS-FLS application to other DoD sites –Ameresco is moving forward to apply the technology at other DoD facilities such as Parris Island and Soto Cano. GE is also actively involved with a ESPC project at Diego Garcia Naval Station. Furthermore Portsmouth Naval Shipyard has released an ESPC to be developed since award of this demonstration and selected Ameresco to perform. This new ESPC will build out the demonstration to include additional generation and extend to the remaining two substations (Franklin, Substation 2).

7.0 COST ASSESSMENT

The following costing and valuation analysis provides information useful to those who may be considering developing a project similar to this demonstration. Included are the upfront costs to purchase major technology components, design and build the system, and the routine maintenance and fees required to operate the system over its lifetime. Operational value of these systems comes in the form of avoided costs and generation of revenue through participation in ancillary services. Our conclusion is that both technologies offer quantifiable value to a project.

7.1 COST MODEL

Table 7-1A Cost Model for Microgrid Control System with Fast Load Shed

Element	Data Tracked During the Demonstration	Costs
Hardware Capital Costs and Design, Programming, Training	Including: C90, F35s (x8), D400, Server, GPS Clock, Network Switches, Test Switches, UPS units, and Cabinets. See Section 2.1 Included in this purchase is the design and programming necessary to assure a fully operational system crafted specifically to the site, this is a service provided directly by the hardware vendor.	\$ 965,658
Engineering & Design	Installation Design focused on the mechanical, electrical, and civil engineering trades. The integration of the Microgrid Control System and Fast Loadshed System for this demonstration, as in many cases with other DoD facilities, includes retrofitting components into an existing electrical distribution system. Including in-depth review of existing electrical drawings and operating procedures.	\$ 172,913
Installation costs	Labor and materials required to install the system per the Installation Design drawings. This includes substantial wire pulls within the medium voltage electrical breaker lineups. It should be noted that there is potential in the future to utilize fiber optic conversation routers to be housed at each breaker housing and then fiber optic run back to the MCS/FLS control cabinets. This will greatly reduce the volume of copper wire needed and the labor to pull that wire.	\$ 180,985
Project Management & Overhead	We included in this estimate the cost for Project Management to coordinate the design, submittals, scheduling, installation, commissioning, and training for the system. Working with the government, one should expect the facility personnel to be very engaged through the process, requiring a high level of coordination and review through each step of the project from design to commissioning. Note: A demonstration project requires additional milestones and data collection/analysis which other projects may not require.	\$ 250,000
Maintenance	An annual service agreement is recommended to be purchased with the MCS/FLS vendor to provide phone support and two visits to site per year. Maintenance should include control cabinet inspections, dusting of equipment, UPS maintenance, and firmware/software updates.	\$ 28,000/yr
Hardware lifetime	Industrial based electronics and software packages should be expected to be supported by vendors past a number of generation updates of their technology. Thought the hardware may be capable of lasting longer than 20yrs, there will be a point in time when the vendor will no longer provide support for components for earlier product lines.	20yrs
Total Upfront Cost	Not Including Annual Maintenance	\$ 1,569,556

* Pricing above is based on a system primarily designed to perform FLS on up to 30 medium voltage circuits, which is a representation of a system of a high complexity for a government facility. We would expect many facilities to require half or even a quarter of this many circuits. The estimator should keep in mind that utilizing the MCS for control of Distributed Generation Resources (DERs) was not part of this scope and carries a high cost to implement not included in this project.

Table 7-1B Cost Model for Battery Energy Storage System (BESS)

BESS Cost Element	Data Tracked During the Demonstration	Estimated Costs
Hardware Capital Costs and Training	Including: Batteries, Enclosure, Power Conversion System, and Controls. It must be noted that our cost estimates for if this system were built today are dramatically lower. This is due in part to manufacturer selection, as cost for systems vary across competitors. There has also been a downward trend in system costs across the Li-Ion battery market year over year in the range of 15%/yr.	(2013) \$ 1,043,910 (Present) \$ 365,252
Engineering, Design, Permitting	Installation Design focused on the mechanical, electrical, and civil engineering trades. The integration of a BESS for this demonstration, and as in many cases with other DoD facilities, includes retrofitting components into an existing electrical distribution system.	\$ 167,571
Installation costs	Labor and material required to install the system per the Installation Design drawings. This includes any demolition necessary, forming of pads, conduit runs, and cable. It must be noted that for this specific project, we had access to an existing breaker which would otherwise need to be accounted for. Also, we were able to utilize sub-contractors who were already on-site which substantially reduced electrical and civil installation tasks.	\$ 78,905
Project Management & Overhead	We included in this estimate the cost for Project Management to coordinate the design, submittals, scheduling, installation, commissioning, and training for the system. When working with the government, one should expect the facility personnel to be very engaged through the process, requiring a high level of coordination and review through each step of the project from design through commissioning. Note: A demonstration project requires additional milestones and data collection/analysis which other projects may not require.	\$ 150,000
Battery Regen @ Yr 11	Li-Ion battery technology has a long life expectancy in the 20yr range, however this is heavily dependent on the number of charge/discharge cycles performed over the life of the system. For providing Frequency Regulation, as this project was intended for, we expect that life span to drop to around 10yrs for the cell chemistry. Since the rest of the BESS components still have a 20yr life it is economically wise to invest money in replacing the battery cells. As can be seen in the graphs in Section 7.3, the economic life and value of the investment is dramatically increased in performing this added Regen cost. Cost for Regen was not included in this demonstration.	(2013) \$ 417,564 (Present) \$ 146,101
Facility Operational Costs	Fee to ISO-NE to provide MPLS connection in order to participate in Reg Market	\$ 400/mo
Maintenance	BESS components require very little annual maintenance, the costs in this line item are associated mostly with annual inspection.	\$ 5,000/yr
Hardware lifetime	Assuming Battery Regen is performed.	20 Years
Total Upfront Cost	Not Including Annual Maintenance or Regen	\$ 1,440,386

* Pricing above is for a 500kW/500kWh system. In terms of scalability, our market experience is that the cost to capacity curve is linear up to multi MW/MWh systems. This pricing does not apply to utility scale projects in the 10s of MW scale.

7.2 COST DRIVERS

Battery technology costs are on a downward trend with the market seeing on average a 15% reduction year over year. Over the demonstration period of this project, we confirmed this trend. Our analysis covered in the following Section 7.3 goes into detail on our findings. The outcome is that projects which may have not been feasible only 3 years ago may now be viable thanks to the reduced cost in both Li-ion chemistry and power conversion systems. When looking at revenue opportunities, the availability of an ancillary services market for a system to participate in should also be considered. As of today there are a number of markets in development or already operating, with the most mature being in PJM, ISO-NE, and CAISO. Other regions in development and should be looked at are NY-ISO, ERCOT, and MISO. See Figure 3-1 in Section 3.0.

7.3 COST ANALYSIS AND COMPARISON

The following steps in performing the LCC analysis were taken from the NIST 135 Handbook...

PART I: TABLES FOR FEDERAL LIFE-CYCLE COST ANALYSIS

Single Present Value and Uniform Present Value Factors for Non-Fuel Costs

Table A-1 presents the single present value (SPV) factors for finding the present value of future non-fuel, non-annually recurring costs, such as repair and replacement costs and salvage values. The formula for finding the present value (P) of a future cost occurring in year t (C_t) is the following:

$$P = C_t \times \frac{1}{(1+d)^t} = C_t \times SPV_t, \quad \text{where } d = \text{discount rate, and}$$

t = number of time periods (years) between the present time and the time the cost is incurred.

Table A-2 presents uniform present value (UPV) factors for finding the present value of future non-fuel costs recurring annually, such as routine maintenance costs. The formula for finding the present value (P) of an annually recurring uniform cost (A) is the following:

$$P = A \times \frac{(1+d)^N - 1}{d(1+d)^N} = A \times UPV_N, \quad \text{where } d = \text{discount rate, and}$$

N = number of time periods (years) over which A recurs.

UPV (FEMP): To compute the present value of an annually recurring maintenance cost for a renewable energy system over 20 years, go to Table A-2, find the 3.0 % UPV factor for 20 years (14.88), and multiply the factor by the annual maintenance cost as of the base date.

NIST Handbook 135

Table A-1. SPV factors for finding the present value of future single costs (non-fuel)

Number of years from base date	Single Present Value (SPV) Factors		
	DOE	OMB Discount Rates ^a	
	Discount rate 3.0 %	Short term ^b -0.4 %	Long Term ^c 1.1 %
0.25	0.993	1.001	0.997
0.50	0.985	1.002	0.995
0.75	0.978	1.003	0.992
1	0.971	1.004	0.989
2	0.943	1.008	0.978
3	0.915	1.012	0.968
4	0.888	1.016	0.957
5	0.863	1.020	0.947
6	0.837	1.024	0.936
7	0.813	1.028	0.926
8	0.789	1.033	0.916
9	0.766	1.037	0.906
10	0.744	1.041	0.896
11	0.722		0.887
12	0.701		0.877
13	0.681		0.867
14	0.661		0.858
15	0.642		0.849
16	0.623		0.839
17	0.605		0.830
18	0.587		0.821
19	0.570		0.812
20	0.554		0.803
21	0.538		0.795
22	0.522		0.786
23	0.507		0.778
24	0.492		0.769
25	0.478		0.761
26	0.464		0.752
27	0.450		0.744
28	0.437		0.736
29	0.424		0.728
30	0.412		0.720

^aOMB discount rates as of April 2013.

^bShort-term discount rate based on OMB discount rate for 7-year study period.

^cLong-term discount rate based on OMB discount rate for 30-year study period.

Table A-2. UPV factors for finding the present value of annually recurring uniform costs (non-fuel)

Number of years from base date	Uniform Present Value (UPV) Factors		
	DOE	OMB Discount Rates ^a	
	Discount rate 3.0 %	Short term ^b -0.4 %	Long Term ^c 1.1 %
1	0.97	1.00	0.99
2	1.91	2.01	1.97
3	2.83	3.02	2.94
4	3.72	4.04	3.89
5	4.58	5.06	4.84
6	5.42	6.08	5.78
7	6.23	7.11	6.70
8	7.02	8.15	7.62
9	7.79	9.18	8.52
10	8.53	10.22	9.42
11	9.25		10.31
12	9.95		11.18
13	10.63		12.05
14	11.30		12.91
15	11.94		13.76
16	12.56		14.60
17	13.17		15.43
18	13.75		16.25
19	14.32		17.06
20	14.88		17.87
21	15.42		18.66
22	15.94		19.45
23	16.44		20.22
24	16.94		20.99
25	17.41		21.75
26	17.88		22.51
27	18.33		23.25
28	18.76		23.99
29	19.19		24.71
30	19.60		25.43

^aOMB discount rates as of April 2013.

^bShort-term discount rate based on OMB discount rate for 7-year study period.

^cLong-term discount rate based on OMB discount rate for 30-year study period.

Annual Supplement to NIST Handbook 135 (2013) <http://dx.doi.org/10.6028/NIST.IR.85-3273-28>

The following calculations represent Present value (P) using the methods previously described in the NIST 135 Handbook. The “Calculated” values were performed in excel using the two equations as seen below. The “From Table” values are used for proofing the equations and utilize Tables A-1 and A-2 taken from the NIST 135 Handbook. By bringing all the associated costs and revenue to Present value, we can make a comparison to the initial costs of the system.

Figure 7-1 and Figure 7-2 on the following pages graphically demonstrate the calculations and show the breakeven point on the upfront investment.

$$P = A \times \frac{(1+d)^N - 1}{d(1+d)^N} = A \times UPV_N,$$

$$P = C_t \times \frac{1}{(1+d)^t} = C_t \times SPV_t,$$

Values at time of Demonstration (2013)

P_Initial Cost	\$(1,440,386)	
	Calculated	From Table
P_maint	\$(74,387)	\$(74,400)
P_revenue	\$1,487,747	\$1,488,000
P_regen	<u>\$(216,726)</u>	<u>\$(223,200)</u>
P_sum	\$1,196,634	
P_variance	\$(243,752)	

Total costs versus revenue over the 20-year life of the system resulted in a variance of \$(243,752) in the negative and a breakeven point out past year 20, indicating that this project was not economically feasible at the time of initial investment. However, since the award of this demonstration (2013) battery system components have come down dramatically in cost. This is due to a number of factors but the two primary drivers have been related to an increase in competition with a wider choice of manufacturers entering the market as well as an increase in economies of scale in manufacturing.

There are multiple sources of information which project on average a 15% cost reduction year over year for battery systems. Our findings support this projection. The following calculations represent Present value (P_n) for a system procured in 2017 with the same maintenance and market revenue assumed.

Values at Present (2017)

P _n _Initial Cost	\$(761,728)	
	Calculated	From Table
P _n _maint	\$(74,387)	\$(74,400)
P _n _revenue	\$1,487,747	\$1,488,000
P _n _regen	<u>\$(109,158)</u>	<u>\$(112,419)</u>
P _n _sum	\$1,304,158	
P _n _variance	\$542,474	

Total costs versus revenue over the 20-year life of this system resulted in a variance of \$542,474 in the positive and a breakeven point at the end of year 9, indicating that this project is in fact economically feasible in present conditions.

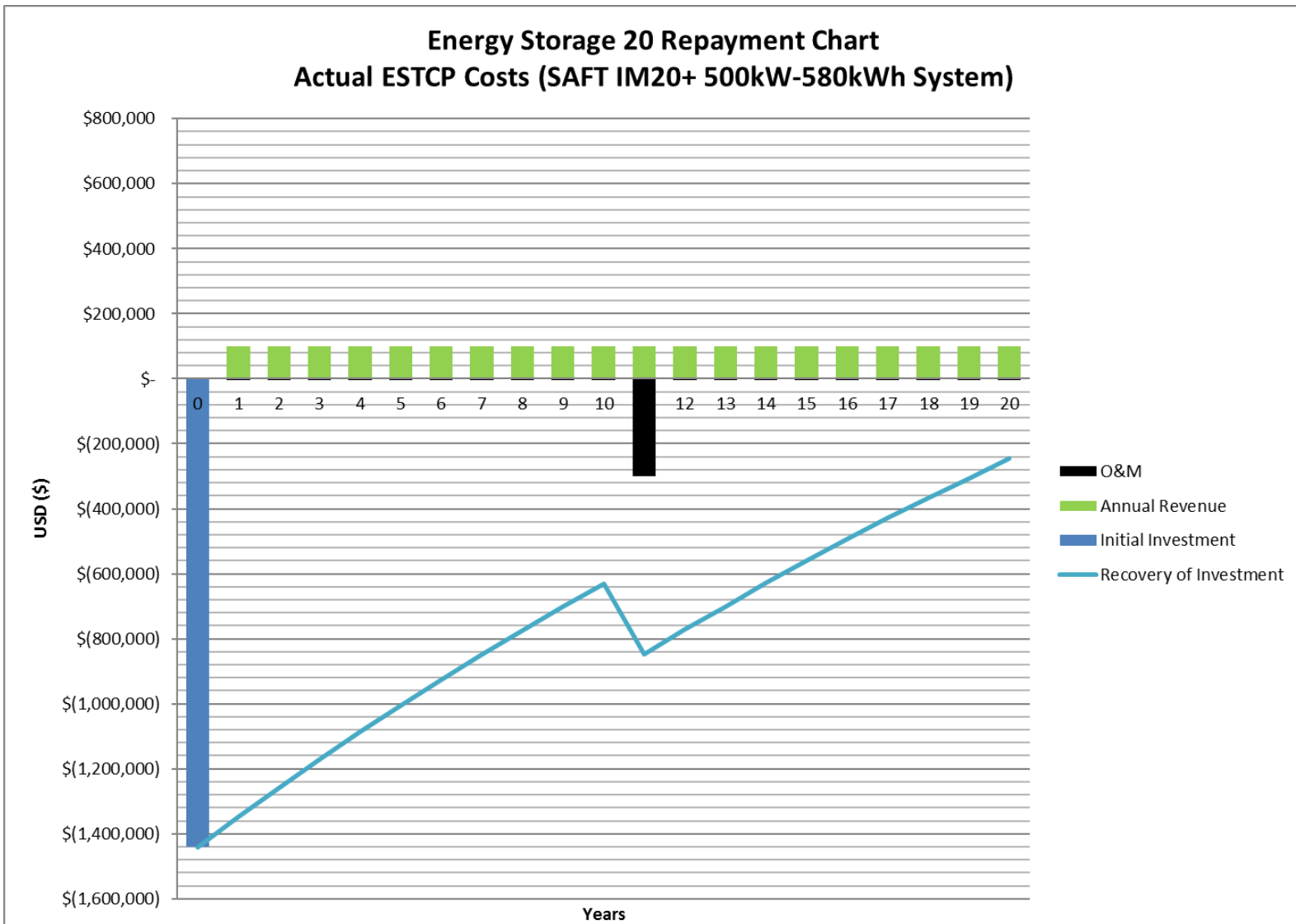


Figure 7-1 20 Year Economics of the 500kW-580kWh Saft IM20+ Battery Energy Storage System Participating in ISO-NE Regulation

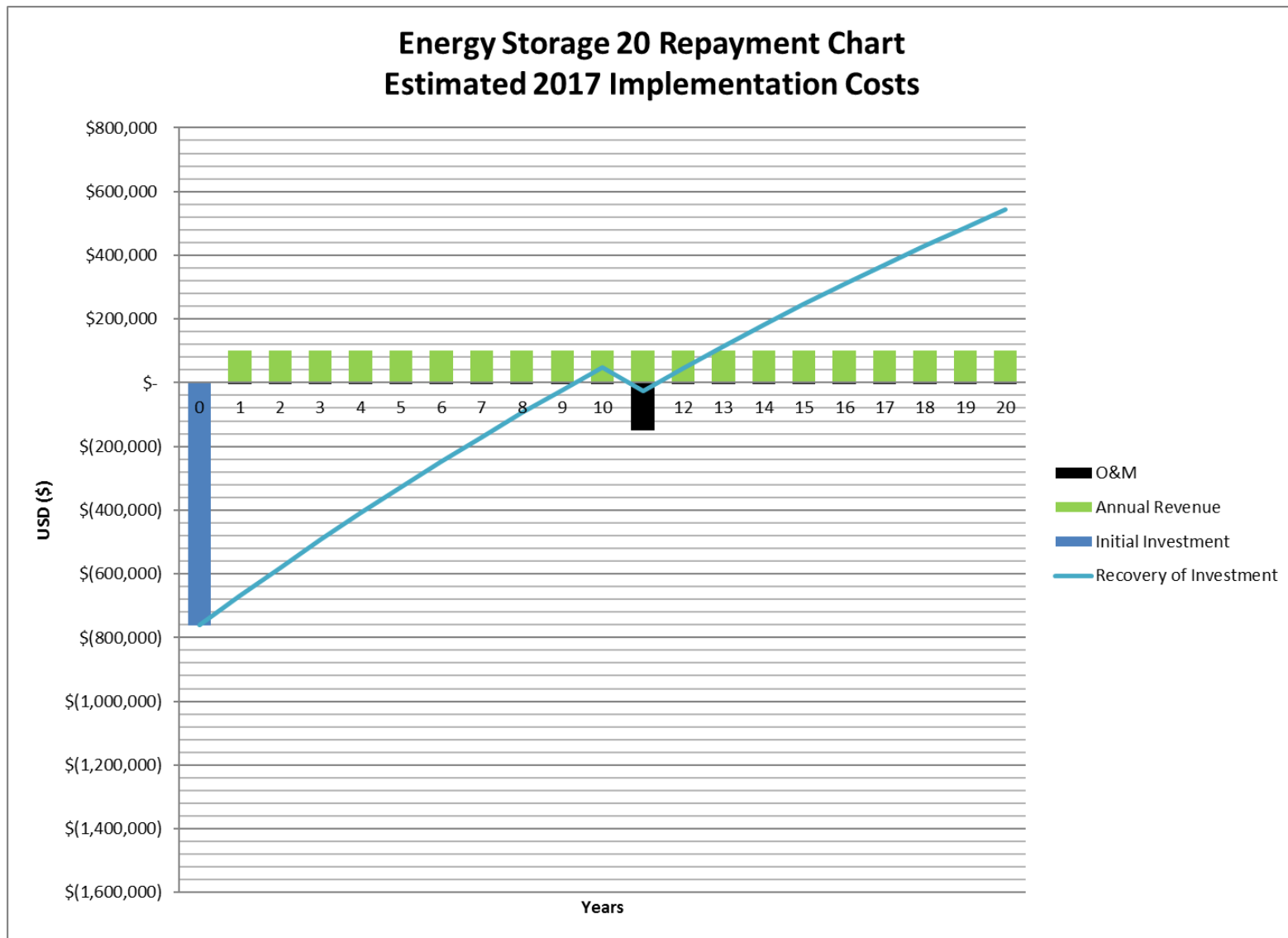


Figure 7-2 Expected 20Yr Economics of a 500kW/500kWh BESS with 2017 Equipment Pricing Participating in ISO-NE Regulation

Calculating Market Revenue (P_revenue)

Ameresco estimated annual revenue that can be received as payment for participation in the ISO-NE Regulation Ancillary Services market. To determine this estimated revenue, Ameresco conducted its own research into the ISO-NE market including analysis of multiple years of actual historical clearing price data and also utilized a third-party consulting service to conduct their analysis of the market. It should be noted, however, that this market is a merchant market and as such the actual revenue garnered is variable from year to year, and that there is a certain level of uncertainty with respect to Ameresco's revenue estimates since this is a newly emerging market.

Through our research, Ameresco assumed an average hourly Regulation Capacity Clearing Price of \$25.00/MWh. Ameresco assumed an annual hourly participation of 8,000 hours. It is noted that the newly established minimum capacity for participation eligibility is 1,000 kW, however for the sake of example for this project an assumed participation capacity of 500kW is used to calculate the annual revenue estimate as:

Annual Regulation Revenue

$$\begin{aligned} &= \text{Average Hourly Reg Payment} * \text{Annual Hours of Service} \\ &* \text{Capacity Provided} = \left(\frac{\$25.00}{\text{MWh}} \right) * \left(8000 \frac{\text{hours}}{\text{year}} \right) * (0.5\text{MW}) = \frac{\$100,000}{\text{year}} \end{aligned}$$

Annual Avoided Cost of Lost Production

During this demonstration we took into consideration what the value may be in the avoided down-time realized in maintaining priority loads during a Loss of Utility (LoU) through implementation of the Fast Load Shed (FLS) system. Through interview with the PWD staff and our own personal experience in being on-site at Portsmouth Naval Shipyard since 2001, we know that the facility on average experiences an LoU two to three times per year. Over the demonstration period we captured three LoU events, confirming this average. Pre-existing to the implementation of FLS, the facility would experience a base-wide blackout during an LoU. This was due to an imbalance between a greater number of loads versus available on-site generation capacity. The overload resulted in the Gas Turbine Generators (GTGs) tripping off-line. Blackouts can have ranged anywhere from no less than 30 minutes up to 2 hours until the GTGs are re-started and power to priority loads is restored. With the FLS activated, we can eliminate this black-out period by matching the number of priority loads to be saved to the available on-site generation capacity.

Though the Navy does not budget for down-time in production, we learned from PWD staff that a good estimate is a cost of \$100,000/hr. Assuming an event lasts on average one hour with the total facility load on average being 15MW, we can estimate an average cost per MW (\$/MW) for the value of generation in relation to production cost.

$$\text{Production Cost per MW} = \frac{\left(\frac{\$100,000}{1\text{hr}} \right)}{15\text{MW}_{\text{load}}} = \$6,666/\text{MW}$$

The FLS is capable of saving between 5MW and 10MW of priority loads depending on the number of GTGs operating at time of LoU. Two typical modes of operation exist, first being Summer with one GTG (5MW) online, and the second being Winter with two GTGs (10MW) online. Assuming each generator is running at full capacity, which is typical operation, we performed two additional calculations to come to a total Lost Opportunity Cost (LOC) per event at the time of an LoU.

$$LOC_{Summer} = \$6,666 \times 5MW = \$33,000$$

$$LOC_{Winter} = \$6,666 \times 10MW = \$66,000$$

*Note that one of the performance objectives was to capture and analyze value of the BESS saving additional loads above what could be carried by the CGTs. This is the function previously noted as a “bridge” where the BESS would hold load until the emergency generators came on-line. Ultimately we were unsuccessful in getting the GE C90 to properly include this capacity in its calculation. Additional programming and tests would need to be performed to verify if this function is viable to count towards the LOC.

During the demonstration, we captured two LOC_{Summer} events and one LOC_{Winter} event, which resulted in an Annual Avoided Cost (AAC) of \$132,000. Dividing the combined implementation costs found in Table 2.A by the ACC, we can now estimate a simple payback on the investment.

$$Simple Payback = \frac{\$1,569,556}{(\$33,000 \times 2) + (\$66,000 \times 1)} = 11.89 \text{ Years}$$

The result is a 12 year payback on the system and in theory this is an attractive savings. However it must be realized that a Lost Opportunity Cost is not a value that most if any government facility takes into consideration today when budgeting for its operations. As an energy services company (ESCO) providing energy savings performance contracts (ESPCs) to the Federal government it is Ameresco’s experience that costs of this nature are not presently identified under the list of approved energy conservation measures (ECMs).

With that said, in review of the positive outcome from the above results, we would certainly be open to further discussions regarding the future potential of the government opening up LOC as a potential ECM to be added to an ESPC. The potential to apply such cost savings to other facilities is very real and with a broad application. Most any facility which serves a daily operational duty could benefit from deferring a disruption in its function during an emergency power outage and having the opportunity to include this in an ESPC could provide means to fund implementation of the technology.

Furthermore the implementation of technologies of this nature provide a greater yet intangible value above LOC in the form of increasing national security which can ultimately avoid casualties in the form of both government property and lives during times of crisis.

8.0 IMPLEMENTATION ISSUES

Battery Manufacturers: One challenge in bringing our demonstration from concept to activation was procurement of the grid-tied battery. Over the development phase, we witnessed battery companies, some of whom we sourced pricing proposals from for this project, go through substantial changes. From bankruptcy and plant closures, to limited component availability and redesign of systems resulting in extended product lead-times.

With each manufacturer offering a unique design and battery chemistry our task was even more challenging as a change in manufacturer meant revision to our installation design as well as electrical and communication specifications.

After re-visiting a number of manufacturer proposals settled on procuring a battery from Saft. The battery is from their Intensium Max product line. The IM20 is comprised of eleven (11) Li-ion modules equaling 580kWh of energy storage capacity, populated within a shipping container, providing power to run a 500kW bi-directional inverter.

Previously we were working to partner with GE Transportation to procure a battery from their Durathon Sodium-Nickel product line and in our original proposal to ESTCP we had been looking to partner with A123 to provide a Li-ion battery. We also considered an advanced lead-acid battery from Xtreme Power.

The decision to go with Saft was based on shorter lead-times, an installation design closer to the original A123 proposal, and more competitive pricing in \$/kW compared to competitors. The \$/kW offered by Saft was in line with A123's pricing and gave us the ability to meet our original 500kW proposed output where with the GE Durathon we would have needed to de-rate the system to 250kW.

Though the change in batteries set us back in finalizing our sub-contracts, we stayed on target in meeting our installation dates and within the budget set aside in the grant.

Battery Location and Installation: Another particular challenge we faced was determining a final location for the BESS. Choosing a place for the battery proved to be troublesome due to the weight, dimensions, and mounting requirements of the integrated shipping container. Originally the project had intended an exterior installation but due to limited appropriate space around the perimeter of the Power Plant, as well as neighboring construction in progress, this proved to be a substantial obstacle. We decided on an indoor location as an alternate which added some technical requirements such as Structural Analysis of the decking, Elevation Clearances, and Heat Load Calculations (See Appendix H). All of which were completed and received NAVFAC's record of review and approval. An indoor installation proved to introduce complications, some which were anticipated and some which were not. One of the more difficult obstacles was devising a plan to crane the battery container into the building. A few weeks were lost in coming to an agreement on a final plan for installing the battery which resulted in an equal delay in commencing with the preparatory phase of installation. Ultimately the hurdles were overcome with an end result of a successful installation which the Navy is satisfied with.

BESS Communications Integration

Saft IM20 and Dynapower BESS Site Controller: A number of challenges presented themselves during integration of the communication devices between the Saft IM20 and Dynapower Site Controller. To date, these two devices had never been programmed for integration, so it was our task to bring both parties together to understand the operating requirements of each manufacturer's design. One challenge is that Saft's system is programmed in CANBUS where as Dynapower and GE are using Modbus so conversion within the Site Controller was necessary and proved to be a programming challenge which took multiple weeks and a return trip by the programmer to get the systems to operate as intended. In addition, Dynapower worked with Ameresco and Saft to develop a Battery Charge Management program which took advantage of ISO-NE's "trinary" signal by biasing the battery charge/discharge in order to prevent fading. Low SOC cut-out protection was also written and included in the software update.

BESS Site Controller and ISO-NE Network: Also, during ISO-NE Circuit Testing it was identified that the Site Controller was not reporting Reg High/Low Limits as expected. Dynapower and SGC Engineering worked with Ameresco to better understand the ISO-NE communication register, which operates on yet another protocol known as DNP3 which is converted into Modbus via an RTU housed within the Site Controller cabinet.

BESS Site Controller and GE MCS/FLS: During integration of the BESS Site Controller communications into the GE MCS/FLS system, we experienced challenges here as well. The challenge was rooted in the fact this was the first time GE had worked to integrate with these two specific manufacturers and also as we understand the first time our GE team had integrated a BESS into an FLS schema. The result was that during PVT in December 2015, the BESS was only partially operational. Testing proved that the unit could operate as a "buffer" however additional programming in the C90 controller was necessary in order to operate as a "bridge". *(Please review Sections 2.2 and 6.0 with further explanation of the "buffer" and "bridge" functions)* After some additional programming by GE we received clearance by NAVFAC to perform another round of PVT in December of 2016 however after performing the test and reviewing the post-test data it was determined that the C90 failed to operate the BESS as a "Bridge". The programming error has been identified and the change has been determined to be set aside until a second phase build-out of the microgrid kicks off under Ameresco's ESPC development at Portsmouth and Norfolk shipyards. It is still inconclusive if the BESS is indeed fast enough to respond in concert with the FLS to act as a "Bridge" and carry additional critical loads until additional generation can be brought online. The size of the BESS being 500kW on a 12+MW load makes it difficult to capture if indeed an additional priority load was saved during testing, however we are certain that the FLS calculation did not take it into account as intended. Take-away is that further development is necessary to implement BESS technology as a "Bridge" in microgrids such as this demonstration set out to prove.

Despite these challenges, overall the host site has been pleased with the operational outcome of the FLS and the BESS "Buffer" thus in turn the system has been left operational and is planned to stay activated going forward. We also look forward to performing turn-over and acceptance of the system to the Navy, as it is our understanding that the host site is interested in taking over ownership and operation of the system.

Lessons learned, Ameresco has decided in future projects to source an integrated package from a single vendor when at all possible. There may be opportunity to procure separate systems at a lower price, however the task of bringing multiple parties together on-site or at a select manufacturer's testing facility is a logistical task which must be considered as an added cost.

BESS Reliability / Quality Control

See Appendix K for a complete list of Saft IM20 Warranty Issues to date.

Since installation of the IM20 container in June of 2014 Saft has returned to site to correct a number of component failures including two battery modules which had been identified as having failed cells, and also replacement of all 280 Safety Monitoring Units (SMUs) due to a factory recall identifying a redundant failure of circuitry on multiple IM20 units manufactured within the same time period as the one for this demonstration. We also experienced a failure of the main DC disconnect switch on the battery container, Saft was able to get this covered under warranty with ABB as well. In 2016 we experienced a number of additional component failures on the IM20 unit which prevented us from testing the BESS in sequence with some additional FLS testing in August. The failures were rooted in multiple fire suppression sensors going into trouble as well as half of the shunt trip breakers (5 out of 10) on the battery strings failing. Both issues prevented the system from being operated safely and in turn the unit was left off-line for approximately 2 months. After many hours of troubleshooting, identifying corrective actions, and two site visits Saft was successful in remedying the issues.

Saft has corrected every issue to date under warranty, which is commendable, however Ameresco and NAVFAC share some reservation on the future operational reliability of the unit. In order to assure ongoing reliability of the system, it has been determined that Saft would need to return to PNS to perform at the least a baseline state of health test on the battery cells as well as a thorough visual inspection of internal circuitry. Pending outcome of the testing and inspection, we see potential for additional maintenance or corrective repairs.

When weighing the costs to bring the system into good operating condition and ongoing annual maintenance against the benefits the BESS could provide post demonstration, it has been agreed by Ameresco and the host site that the potential costs outweigh the benefit. This is largely in part due to the unavailability of the BESS to continue participation in the ISO-NE regulation market due to the 500kW max capacity of our unit falling below the 1MW minimum capacity set by ISO-NE. This change in the market participation rules went into effect at the end of the Pilot program for which the demonstration was set up to run.

Battery Fire Suppression System Certification: We learned that the Navy required additional inspection and acceptance of the Battery Fire Suppression System than what was provided with the Saft container and what we had accounted for. The PNS Fire Department set forth requirements the system must meet under NFPA 2001 and NFPA 72 (See Appendix J). Though Saft's system satisfied the majority of requirements there were a couple tests outstanding not previously performed at the Saft factory. This included an "Enclosure Integrity Test" and "Discharge Pipe Integrity Test". Ameresco hired a 3rd party Fire Protection testing company to perform the checks onsite. Out of this inspection there was a smoke sensor deficiency identified pertaining to the interface between sensors and overhead air plenum.

Soft spent several visits onsite to satisfy the Navy Fire Protection Engineers request for smoke detectors meeting the NFPA code, modifications were performed to the overhead plenum within the battery container and after re-inspection the Navy FPE accepted the Fire Suppression System.

Regulation Market Rules: With the move to deregulate the electric utility market beginning in 1999, opportunities have developed in various regions of the U.S. for end users to participate in ancillary services such as Demand Response and Frequency Regulation. With the utilization of battery storage steadily increasing, and the support of FERC, ISO New England developed a pilot program creating a trial period for the technology to participate in Frequency Regulation. ISO-NE's pilot was originally scheduled to expire on Oct. 1st 2014, which aligned well with our planned demonstration period. At that point participants in the Pilot were to be required to comply with the new rules, under FERC Order 755, or discontinue service. The largest challenge in ISO-NE's new program was meeting a 1MW minimum participation capacity (our project is 500kW). In Q1 of 2014 we received notice from ISO-NE that the transition date was being accelerated to May 21st, 2014. Ameresco pursued an extension on the 1MW requirement to the original date of Oct 1st 2014, which we obtained, and proceeded with meeting the additional requirements necessary to participate in the Regulation Market. On May 15th ISO-NE announced that the transition would be delayed due to FERC rejecting the new rules filing, and that the Pilot program would continue operation until March 31st of 2015. After this date all fast response units were to exit the Pilot program and be required to meet the new 1MW requirement.

Interconnection Agreement: Unfortunately, we were unsuccessful in obtaining an Interconnection Agreement in time as required by ISO-NE in order to participate in the Regulation market. In February of 2014 Central Maine Power, the public utility, issued an IA for signing at which point on April 2nd of 2014 the Navy responded to CMP with request to changes in the Terms & Conditions. This request for changes would have put us into a 45+ day petition process with the Maine Public Utilities Commission for review and consideration for approval of changes to the Indemnity clause. Fortunately, the Navy weighed the size of this project (500kW) against the legal trouble to go through the petition process and decided to accept the T&Cs as they were originally worded. Despite this decision, the final signing of the Interconnection Agreement by the Navy did not take place until August of 2014. At this point we were optimistic that we would have approval to proceed with the demonstration from September of 2014 through March of 2015, giving us 7 months of run time in the market. Following this signing we learned from the Navy that they had discovered in the process that the government's master service agreement (N40085-15-F-7703, see Appendix F) to procure electricity from Central Maine Power had expired. This diverted us into an administrative contracting queue to update the master contract terms and add a MOD to include operation of the BESS at PNS. To our dismay this process was extremely slow and ultimately resulted in the passing of the expiration of the Pilot program on March 31st 2015 with a contract finally being signed and executed in May of 2015.

From this point Ameresco then explored alternatives to bring the BESS up to the new Regulation market rules before completion of the ESTCP demonstration period for the FLS which was set for completion in December of 2016. One option we explored was to work with Customized Energy Solutions (CES) to aggregate the 500kW BESS at PNS with other fast response resources within the ISO-NE territory in order to get us up to the 1MW minimum bid capacity. This would include locating another participant site and setting up necessary telemetry/ hardware/ programming.

We met with CES and refined a Scope of Work identifying division of responsibilities in implementation and operation of the system for the duration of the demonstration along with associated costs. Ultimately our efforts did not identify another host site which was ready to activate a system within the timeframe we had for the demonstration period.

Another option Ameresco considered was to increase the size of the BESS at PNS to 1MW. After weighing the cost and logistics to develop and install additional capacity, we determined that this was not an option the host site was interested in at that time. In the same timeframe of considering options, Ameresco learned that PNS was in the process of assembling a request to the Navy to solicit a new Energy Saving Performance Contract for the facility. Our team saw this as an ideal opportunity to expand the BESS under that future contract. In early 2016 Ameresco was given notice that we have been selected to develop the ESPC for PNS, we are now looking forward to expanding upon the BESS in that project and re-visit participation in the ISO-NE Regulation Market.

MCS/FLS Testing and Operation: During Performance Verification Testing (PVT) in December of 2015 we uncovered a number of errors in settings and programming within the GE hardware, namely the F35s, C90, and D400. Even though the majority of commissioning had already been performed, there were certain operations of the system which could not be tested until the PVT, simply because some functions required activation and triggering of the FLS. Due to the extreme sensitivity of the Portsmouth Naval Shipyard maintaining power, we had a small window of approval to perform the PVT. On more than one occasion the tests did not run exactly as reviewed during the preparatory briefings presented to the Base Command. The result was clear concern from Navy personnel on how to proceed with correcting the issues while maintaining assurance that an inadvertent trip would not occur on a critical load. Even though we had two levels of safety in place (software and mechanical based lockouts) to ensure no inadvertent trips, the facility follows strict nuclear related protocols which require an all stop if testing deviates from the plans reviewed during the briefing. GE was able to identify the programming issues in each case within a timely manner and re-brief with the Navy to instill sufficient confidence to resume testing, successfully completing the PVT, and ultimately gaining approval for us to activate the system to commence with the 12 month demonstration period.

Even after completing PVT and activation of the system, in following weeks PNS later experienced an inadvertent trip of loads by the FLS. It was found that the issue manifested from a routine cycling of the Power Plant emergency diesel generators. We were fortunate that the event was isolated to just three (3) loads which were marked as non-critical and did not result in a disconnection from the utility. NAVFAC was able to recover from the isolated outage of these three breakers with minimal disruption to the Shipyard as whole. Working with GE and NAVFAC we determined that the trouble was rooted in the diesel breakers being left in an active infeed state where the two related F35 relays were monitoring and reporting these assets as generation necessary to keep loads satisfied. This state of monitoring was incorrect since the Shipyard was still connected to the utility and would have had no problem maintaining capacity to all loads (both non-critical and critical), where the utility would have simply picked up where the diesel left off. The GE team did an excellent job of being available for conference calls, data analysis, quickly identifying the issue, and returning to site to correct the settings in the two F35s. NAVFAC, Ameresco, and GE then proceeded to go through some additional review of how the C90 and F35s function and take the system through a series of testing scenarios over a three day period, and the end of this testing the FLS was approved to be put back online.

This was an excellent example of how a demonstration can provide great benefit to implementing relatively complex controls related to Microgrids in a grid-stability sensitive environment. It is also a lesson in the value of performing as much simulated testing as possible at the factory prior to integration with a DoD facility.

MIT Lincoln Laboratories hosted a symposium in February of 2017 demonstrating the advancement in simulating microgrid controls. Many of the leading manufacturers of controls hardware attended this event to demonstrate the newest capabilities to perform simulations utilizing their field hardware in testbeds. Ameresco attended the symposium and see this as an excellent opportunity for manufacturers to perform further in-depth testing of systems they design ahead of shipping to the end user's site. Given the sensitive nature of most DoD facilities to continue to operate without interruption to their mission, we highly recommend that future projects pursue this extensive factory testing option ahead of installation and commission on-site.

Islanding and Power Plant Stability: Over the course of the 12 month demonstration period, PNS experienced three accounts in Loss of Utility. In each case a full loss of utility and successful activation of the FLS occurred, however two of these events resulted in the Gas Turbine Generator tripping off-line and a full-blackout of the Shipyard.

The first event took place on 6-21-16 with 4MW of generation on-line from one Gas Turbine Generator and 15MW of load on the facility. The loss of utility was related to a major catastrophic failure of an air switch located just outside the Shipyard on the incoming feed from the utility. A direct short to ground occurred on one phase and in turn resulted in melting of connections on all three phases as well as starting a fire on the ground wire running down the pole. This short resulted in the GTG tripping on a Differential Relay current fault ahead of F12 (utility breaker) opening, which in turn initiates the FLS. The result is that though the FLS operated as designed the Shipyard still went black due to the loss of its only on-line generator. Data from the F35s, C90, and HMI was collected and full analysis can be found in Section 6.0 of this report.

The second live event occurred on 07-08-16 with 6.5MW of generation on-line from one GTG and two Emergency Diesel Generators, which coincidentally were online for routine cycling when the loss of utility occurred. The facility load was 11.6MW at 6:55am during the time of the event which is lower than the typical 16MW peak expected during mid-day. This event resulted in all mission critical feeders going out to the submarines being saved along with all but two breakers in the FLS priority list, the shedding of non-critical loads out at Sub2 relieved the majority of load required to be shed in order to match on-site generation. One thing to note is that the BESS did not dispatch during this event due to the EDGs already being online at the time of FLS, so we were not successful in capturing a live operation of the BESS. Utility power was restored hours later and the FLS was reset and brought back on-line.

The third loss of utility took place on 10-16-16. The disturbance on the grid is believed to have originated from the utility, resulting in a dramatic sag of voltage on one of the three phases, the utility recloser located at CMP's substation was successful in restoring power within seconds of the event however the disturbance was too long for the on-site GTG to ride through. NAVFAC's findings were inconclusive to what the root cause was on the utility's side.

After analyzing data from the FLS reports, it was determined that the system did indeed shed the appropriate amount of load, assuming that the GTGs were still on-line, however the Shipyard still experienced a black-out because generation was already disconnecting. The conclusion between Ameresco/ GE/ NAVFAC is that the opening of the tie-breaker at Franklin Station on-site was not fast enough to protect the GTGs from a shut-down.

A solution which is being reviewed by all teams is to install a Direct Transfer Trip mechanism between the utility's recloser located at their substation and the tie-breakers at Franklin Station at the Shipyard. This would dramatically reduce the amount of time between an opening of the recloser and in turn opening of the F1 and F12 tie-breakers at the Shipyard. Though this would be an upgrade to the Shipyard's existing interconnection system outside of the ESTCP scope we are working with NAVFAC to price and potentially assist with performing this upgrade under a separate funding mechanism; we see that for the ESTCP demonstration that this is a critical piece of knowledge when considering implementation of a microgrid at other locations.

Take-away is that the FLS has operated as designed. One caveat to this is that it has been determined that the trigger for the FLS (opening of the utility tie(s) at F1 and F12) is not sufficiently fast enough under most LoU cases to successfully prevent the Power Plant from tripping off-line, resulting in black-out of the facility in all but one of the events. Essentially, we have identified that the Gas Turbine Generator protective relay settings trip the units ahead of F1 and F12 opening and initiation of the FLS. NAVFAC is working with the local utility CMP to install a Direct Transfer Trip between their point of connection at F1 and F12 back to the utility's substation recloser which feeds the Shipyard. There is reasonable confidence that this solution will enable the Shipyard to disconnect from the utility before the Power Plant gas turbine(s) go into protective shutdown.

The NAVFAC engineering group at PNS is continuing to work with Central Maine Power (local utility) to devise a solution which will serve to open the utility-tie breaker(s) (F1 and F12) faster/earlier in sequence with opening of the feeder recloser which serves the Shipyard back from the utility's substation. This will serve to more quickly disconnect the Shipyard from a failing utility and set the on-site generation into transition Grid mode to Island mode earlier as well as initiate the FLS earlier. This work is anticipated to be funded directly by the government through NAVFAC PWD-ME's budget.

Appendix A POINTS OF CONTACT

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Chip Palombini	Dynapower	802-652-1378 cpalombini@dynapower.com	Inverter & Site Controller

APPENDIX D - EVENT LOGS FOR LIVE EVENT TESTING OF THE FAST LOAD SHED SOLUTION

This Appendix consists of:

HMI Event Log for Live Event #1 with Comments – 4 pages

HMI Event Log for Live Event #2 with Comments – 2 pages

HMI Site Event Recorder for Live Tests 15-12-08

DEVICE Event Logs for Live Events:

F-F35-1 EVT_221_20151120_090604
72-F35-1D EVT_211_20151120_090604
72-F35-2D EVT_212_20151120_090603
72-F35-3D EVT_213_20151120_090604
72-F35-4D EVT_214_20151120_090604
3-F35-1 EVT_231_20151120_090604
3-F35-2D EVT_232_20151120_090604
3-F35-3 EVT_233_20151120_090604

The **HMI Event Log for Live Event #1 & Event #2 with Comments** - The normal sequence (newest event first followed by a time sequence of older events) in the HMI and the Devices has been reversed so that the oldest event is at the beginning of the Log. The intent of this Log is to explain what has action has occurred, if any beyond logging, within the individual device. This has allowed us to develop the specific sequence of events and to establish the timing of specific system events. The net result is a Table for each Live Event documenting the performance of the FLS and the PNS circuit breakers.

The first nine columns of the Table have cataloged the specific Event number as shown in the individual Device (HMI, F-F35-1, 72-F35-1, 72-F35-2, 72-F35-3, 72-F35-4, and 3-F35-2) Event Log. The individual device event logs are attached². The next 8 columns (Device, Date, Hour, Minute, Seconds, Cause, State and Initiating Device) are as shown on the HMI Event Log and the individual Device Event Log. The Comments column explains what event has been logged in the individual device and provides further details on the action associated with the event. One will find that each device has duplicated the key system events. This provides additional verification of the timing of the events.

HMI EVENT LOG: LIVE EVENT #1 - SINGLE GTG (Summer Operation) - December 8, 2015

DEVICE EVENT NUMBER										Device	Date	Hour	Minute	Seconds	Cause	State (Source)	Initiating Device	Comments	Absolute Time (ms) of Event
HMI	F-F35-1	72-F35-1	72-F35-2	72-F35-3	72-F35-4	3-F35-1	3-F35-2	3-F35-3	3-F35-5										
302			407							72-F35-2	Dec 08 2015	14	4	23.972604	GTG2-10A-OPN	On (C14)	72-10A	GTG #2 Taken OFF-LINE by PNS for this specific Test scenario.	
301		315								72-F35-1	Dec 08 2015	14	26	52.833146	72-3A-OPN	On (C16)	72-3A	PNS Manually opened this load breaker for operational issues.	
300				411						72-F35-3	Dec 08 2015	15	48	0.181784	LS Running	On (R129)	HMI	LIVE TEST #1 FLS ENABLED in C90P by HMI and Verified in 72-F35-3	
299					284					72-F35-4	Dec 08 2015	15	48	0.182150	LS Running	On (R129)	HMI	LIVE TEST #1 FLS ENABLED in C90P by HMI and Verified in 72-F35-4	
298		316								72-F35-1	Dec 08 2015	15	48	0.182211	LS Running	On (R129)	HMI	LIVE TEST #1 FLS ENABLED in C90P by HMI and Verified in 72-F35-1	
297			408							72-F35-2	Dec 08 2015	15	48	0.182295	LS Running	On (R129)	HMI	LIVE TEST #1 FLS ENABLED in C90P by HMI and Verified in 72-F35-2	
296						268				3-F35-1	Dec 08 2015	15	48	0.182510	LS Running	On (R129)	HMI	LIVE TEST #1 FLS ENABLED in C90P by HMI and Verified in 3-F35-1	
295							272			3-F35-3	Dec 08 2015	15	48	0.182683	LS Running	On (R129)	HMI	LIVE TEST #1 FLS ENABLED in C90P by HMI and Verified in 3-F35-3	
294	446									F-F35-1	Dec 08 2015	15	48	0.182743	LS Running	On (R129)	HMI	LIVE TEST #1 FLS ENABLED in C90P by HMI and Verified in F-F35-1	
293							406			72-F35-2	Dec 08 2015	15	48	0.183146	LS Running	On (R129)	HMI	LIVE TEST #1 FLS ENABLED in C90P by HMI and Verified in 3-F35-2	
292				412						72-F35-3	Dec 08 2015	15	48	0.231788	LS Normal	On (R130)	C90P	LIVE TEST #1 FLS STATUS Verified in 72-F35-3	
291					285					72-F35-4	Dec 08 2015	15	48	0.232153	LS Normal	On (R130)	C90P	LIVE TEST #1 FLS STATUS Verified in 72-F35-4	
290										72-F35-1	Dec 08 2015	15	48	0.232214	LS Normal	On (R130)	C90P	LIVE TEST #1 FLS STATUS Verified in 72-F35-1	
289			409							72-F35-2	Dec 08 2015	15	48	0.232298	LS Normal	On (R130)	C90P	LIVE TEST #1 FLS STATUS Verified in 72-F35-2	
288						269				3-F35-1	Dec 08 2015	15	48	0.232514	LS Normal	On (R130)	C90P	LIVE TEST #1 FLS STATUS Verified in 3-F35-1	
287							273			3-F35-3	Dec 08 2015	15	48	0.232680	LS Normal	On (R130)	C90P	LIVE TEST #1 FLS STATUS Verified in 3-F35-3	
286	447									F-F35-1	Dec 08 2015	15	48	0.232746	LS Normal	On (R130)	C90P	LIVE TEST #1 FLS STATUS Verified in F-F35-1	
285							407			3-F35-2	Dec 08 2015	15	48	0.233151	LS Normal	On (R130)	C90P	LIVE TEST #1 FLS STATUS Verified in 3-F35-1	
FLS ENABLED FOR LIVE TEST #1																		FLS ENABLED FOR LIVE TEST #1	ELAPSED TIME (Milliseconds)
CALCULATED EVENT START TIME										F-F35-1	Dec 08 2015	15	51	32.974798	EVENT START TIME			ESTIMATED EVENT START TIME= UTILITY UNAVAILABLE Time minus (F1 Time of Opening) F1 Time of Opening is established when a F1 'b' switch closes. The total time delay associated with this equals Aux Relay delay (32ms) + F35 Debounce Time (2ms) = 34ms.	-34.0
CALCULATED UTILITY UNAVAILABLE TIME										F-F35-1	Dec 08 2015	15	51	33.008798	UTILITY UNAVAILABLE	On (VO6)	F-F35-1	ESTIMATED UTILITY UNAVAILABLE Time = (Osc Trigger On (VO64) Time - 2ms. The F-F35-1 triggers OSCILLOGRAPHY when it determines that the UTILITY is UNAVAILABLE. This is established when F1 is OPEN. The F35 monitors the status of a F1 'b' switch. The F1 breaker did not have a spare 'b' switch, so an auxiliary relay was used to 'multiply' an existing 'b' switch. This auxiliary relay adds a 32ms delay to the indication that F1 is OPEN plus the F35 relay introduces a 2ms 'debounce' delay to the indication that F1 is OPEN. The event monitoring of the UTILITY UNAVAILABLE logic was not enabled but can be established by subtracting the 2ms debounce from the Osc Trigger On (VO64) event.	0.0
284				413						72-F35-3	Dec 08 2015	15	51	33.009814	SYS ISL72-17A	On (R110)	C90P	C90P receives UTILITY UNAVAILABLE GOOSE message from F-F35-1 and C90P sends SYS ISL72-17A (DE 413) command to 72-F35-3 to open Loop Feeder Breaker 72-17A at Power Plant to Franklin Annex Breaker F-15A.	1.0
283					414					72-F35-3	Dec 08 2015	15	51	33.009814	SYS ISL72-18A	On (R111)	C90P	C90P receives UTILITY UNAVAILABLE GOOSE message from F-F35-1 and C90P sends SYS ISL72-18A (DE 414) command to 72-F35-3 to open Loop Feeder Breaker 72-18A at Power Plant to Substation 2 Breaker 2-14A.	1.0
282			410							72-F35-2	Dec 08 2015	15	51	33.009994	SYS ISL72-8A	On (R17)	C90P	C90P receives UTILITY UNAVAILABLE GOOSE message from F-F35-1 and C90P sends SYS ISL72-8A (DE 410) command to 72-F35-2 to open Loop Feeder Breaker 72-8A at Power Plant to Franklin Breaker F-6A.	1.2
281										72-F35-2	Dec 08 2015	15	51	33.009994	SYS ISL72-9A	On (R18)	C90P	C90P receives UTILITY UNAVAILABLE GOOSE message from F-F35-1 and C90P sends SYS ISL72-9A (DE 411) command to 72-F35-2 to open Loop Feeder Breaker 72-9A at Power Plant to Substation 2 Breaker 2-6A.	1.2
280	448									F-F35-1	Dec 08 2015	15	51	33.010798	Osc Trigger	On (VO64)	F-F35-1	Oscillography Trigger asserted in F-F35-1 by directly detecting UTILITY UNAVAILABLE (monitoring of status of F1 & F12).	2.0
279	449									F-F35-1	Dec 08 2015	15	51	33.010798	OSCILLOGRAPHY TRIGD		F-F35-1	OSCILLOGRAPHY TRIGD verified	2.0
278							408			3-F35-2	Dec 08 2015	15	51	33.011203	SYS ISL 3-7A	On (R124)	C90P	C90P receives UTILITY UNAVAILABLE GOOSE message from F-F35-1 and C90P sends SYS ISL command to 3-F35-2 (DE 408) to open Loop Feeder Breaker 3-7A at Substation 3 to Franklin Breaker F-4A.	2.4
277								409		3-F35-2	Dec 08 2015	15	51	33.011203	SYS ISL3-13A	On (R125)	C90P	C90P receives UTILITY UNAVAILABLE message from F-F35-1 and C90P sends SYS ISL command to 3-F35-2 (DE 409) to open Loop Feeder Breaker 3-13A at Substation 3 to Franklin Annex Breaker F-14A.	2.4
276										72-F35-3	Dec 08 2015	15	51	33.011901	FAULT RPT TRIG		C90P	FAULT RPT TRIG (DE 415) by SYS ISL72-17A (DE 413) command received at 72-F35-3	3.1

HMI EVENT LOG: LIVE EVENT #1 - SINGLE GTG (Summer Operation) - December 8, 2015

HMI	F-F35-1	DEVICE EVENT NUMBER							Date	Hour	Minute	Seconds	Cause	State (Source)	Initiating Device	Comments	Absolute Time (ms) of Event
		72-F35-1	72-F35-2	72-F35-3	72-F35-4	3-F35-1	3-F35-2	3-F35-3									
275				416					Dec 08 2015	15	51	33.011901	FAULT RPT TRIG		C90P	FAULT RPT TRIG (DE416) by SYS ISL72-18A (DE 414) command received at 72-F35-3	3.1
274				417					Dec 08 2015	15	51	33.011901	Osc Trigger	On (VO64)	C90P	Osc Trigger (DE417) by SYS ISL72-17A (DE413) & SYS ISL72-18A (DE414) commands received at 72-F35-3	3.1
273				418					Dec 08 2015	15	51	33.011901	OSCILLOGRAPHY TRIG'D		72-F35-3	OSCILLOGRAPHY TRIG'D verified	3.1
272				419					Dec 08 2015	15	51	33.011901	Trip 72-17A	On (CO5)	72-F35-3	Trip 72-17A (DE 419) Contact Output Asserted 2ms after SYS ISL72-17A (DE 413) command received at 72-F35-3	3.1
271				420					Dec 08 2015	15	51	33.011901	Trip 72-18A	On (CO6)	72-F35-3	Trip 72-18A (DE 420) Contact Output Asserted 2ms after SYS ISL72-18A (DE414) command received at 72-F35-3	3.1
270				421					Dec 08 2015	15	51	33.011901	Shed 72-5A	On (RI5)	C90P	All SHED commands from C90P detected at 72-F35-3 (DE 421-424) 2ms after initial SYS ISL72-17A & SYS ISL72-18A commands received at 72-F35-3 (DE 413 & 414) & at 72-F35-2 (DE 410 & 411)	3.1
269				422					Dec 08 2015	15	51	33.011901	Shed 72-21A	On (RI12)	C90P		3.1
268				423					Dec 08 2015	15	51	33.011901	Shed 72-25A	On (RI15)	C90P		3.1
267				424					Dec 08 2015	15	51	33.011901	Shed 3-6A	On (RI23)	C90P		3.1
266		318							Dec 08 2015	15	51	33.012019	Shed 72-5A	On (RI5)	C90P		3.2
265		319							Dec 08 2015	15	51	33.012019	Shed 72-21A	On (RI12)	C90P	All SHED commands from C90P detected at 72-F35-1 (DE 318-321) 2ms after initial SYS ISL commands received at 72-F35-3 (DE 413 & 414) & at 72-F35-2 (DE 410 & 411)	3.2
264		320							Dec 08 2015	15	51	33.012019	Shed 72-25A	On (RI15)	C90P		3.2
263		321							Dec 08 2015	15	51	33.012019	Shed 3-6A	On (RI23)	C90P		3.2
262			412						Dec 08 2015	15	51	33.012080	FAULT RPT TRIG		72-F35-2	FAULT RPT TRIG (DE 412) by SYS ISL 72-8A (DE 410) command Received at 72-F35-2	3.3
261			413						Dec 08 2015	15	51	33.012080	FAULT RPT TRIG		72-F35-2	FAULT RPT TRIG (DE 413) by SYS ISL 72-9A (DE 411) command Received at 72-F35-2	3.3
260			414						Dec 08 2015	15	51	33.012080	FAULT RPT TRIG		72-F35-2	FAULT RPT TRIG (DE 414) by unknown	3.3
259			415						Dec 08 2015	15	51	33.012080	Osc Trigger	On (VO64)	C90P	Osc Trigger (DE415) by SYS ISL72-8A (DE410) & Sys ISL72-9A (DE411) commands received at 72-F35-2	3.3
258			416						Dec 08 2015	15	51	33.012080	OSCILLOGRAPHY TRIG'D		72-F35-2	OSCILLOGRAPHY TRIG'D verified	3.3
257			417						Dec 08 2015	15	51	33.012080	Trip 72-8A	On (CO2)	72-F35-2	Trip 72-8A (DE417) Contact Output Asserted 2ms after SYS ISL72-8A (DE 410) command received at 72-F35-2	3.3
256			418						Dec 08 2015	15	51	33.012080	Trip 72-9A	On (CO5)	72-F35-2	Trip 72-9A (DE418) Contact Output Asserted 2ms after SYS ISL72-9A (DE 411) command received at 72-F35-2	3.3
255			419						Dec 08 2015	15	51	33.012080	Shed 72-5A	On (RI5)	C90P		3.3
254			420						Dec 08 2015	15	51	33.012080	Shed 72-21A	On (RI12)	C90P	All SHED commands from C90P detected at 72-F35-2 (DE 419-422) 2ms after initial SYS ISL command received at 72-F35-3 (DE 413 & 414) 72-F35-2 (DE 410 & 411).	3.3
253			421						Dec 08 2015	15	51	33.012080	Shed 72-25A	On (RI15)	C90P		3.3
252			422						Dec 08 2015	15	51	33.012080	Shed 3-6A	On (RI23)	C90P		3.3
251				286					Dec 08 2015	15	51	33.012107	Shed 72-5A	On (RI5)	C90P		3.3
250				287					Dec 08 2015	15	51	33.012107	Shed 72-21A	On (RI12)	C90P		3.3
249				288					Dec 08 2015	15	51	33.012107	Shed 72-25A	On (RI15)	C90P		3.3
248				289					Dec 08 2015	15	51	33.012107	Shed 3-6A	On (RI23)	C90P		3.3
247						270			Dec 08 2015	15	51	33.012832	Shed 72-5A	On (RI5)	C90P		4.0
246						271			Dec 08 2015	15	51	33.012832	Shed 72-21A	On (RI12)	C90P	All SHED commands from C90P detected at 72-F35-1 (DE 270-273) 2ms after initial SYS ISL command received at 72-F35-2 (DE 410 & 411) & 72-F35-3 (DE 413 & 414).	4.0
245						272			Dec 08 2015	15	51	33.012832	Shed 72-25A	On (RI15)	C90P		4.0
244						273			Dec 08 2015	15	51	33.012832	Shed 3-6A	On (RI23)	C90P		4.0
243	450								Dec 08 2015	15	51	33.012879	Trip F-5	On (CO1)	C90P	Trip F-5 (DE 450) Contact Output Asserted 4ms after F-5 LS REQ (VO1) request sent from F-F35-1 to C90P (No DE - Event logging not enabled for LS REQ)	4.1
242	451								Dec 08 2015	15	51	33.012879	Trip F-9	On (CO2)	C90P	Trip F-9 (DE 451) Contact Output Asserted 4ms after F-9 LS REQ (VO2) request sent from F-F35-1 to C90P (No DE - Event logging not enabled for LS REQ)	4.1
241	452								Dec 08 2015	15	51	33.012879	Trip F-10	On (CO5)	C90P	Trip F-10 (DE 452) Contact Output Asserted 4ms after F-10 LS REQ (VO3) request sent from F-F35-1 to C90P (No DE - Event logging not enabled for LS REQ)	4.1
240	453								Dec 08 2015	15	51	33.012879	Shed 72-5A	On (RI5)	C90P		4.1
239	454								Dec 08 2015	15	51	33.012879	Shed 72-21A	On (RI12)	C90P		4.1
238	455								Dec 08 2015	15	51	33.012879	Shed 72-25A	On (RI15)	C90P	All SHED commands from C90P detected at F-F35-1 (DE 453-457) 3ms after initial SYS ISL commands received at 72-F35-2 (DE 410 & 411) & 72-F35-3 (DE 413 & 414).	4.1
237	456								Dec 08 2015	15	51	33.012879	Shed 3-6A	On (RI23)	C90P		4.1
236	457								Dec 08 2015	15	51	33.012879	Shed F5-9-10	On (RI28)	C90P		4.1

HMI EVENT LOG: LIVE EVENT #1 - SINGLE GTG (Summer Operation) - December 8, 2015

DEVICE EVENT NUMBER																	Absolute Time (ms) of Event	
HMI	F-F35-1	72-F35-1	72-F35-2	72-F35-3	72-F35-4	3-F35-1	3-F35-2	3-F35-3	Device	Date	Hour	Minute	Seconds	Cause	State (Source)	Initiating Device	Comments	
235							274		3-F35-3	Dec 08 2015	15	51	33.012912	Shed 72-5A	On (RI5)	C90P	All SHED commands from C90P detected at 3-F35-3 (DE 274-277) 3ms after initial SYS ISL commands received at 72-F35-2 (DE 410 & 411) & 72-F35-3 (DE 413 & 414).	4.1
234							275		3-F35-3	Dec 08 2015	15	51	33.012912	Shed 72-21A	On (RI12)	C90P		4.1
233							276		3-F35-3	Dec 08 2015	15	51	33.012912	Shed 72-25A	On (RI15)	C90P		4.1
232							277		3-F35-3	Dec 08 2015	15	51	33.012912	Shed 3-6A	On (RI23)	C90P		4.1
231							410		3-F35-2	Dec 08 2015	15	51	33.013289	FAULT RPT TRIG		C90P	FAULT RPT TRIG (DE 410) by SYS ISL 3-7A (DE 408) command received at 3-F35-2	4.5
230							411		3-F35-2	Dec 08 2015	15	51	33.013289	FAULT RPT TRIG		C90P	FAULT RPT TRIG (DE 411) by SYS ISL 3-13A (DE 409) command received at 3-F35-2	4.5
229							412		3-F35-2	Dec 08 2015	15	51	33.013289	Osc Trigger	On (VO64)	C90P	OSC Trigger (DE 412) by SYS ISL 3-13A (DE 409) & Sys ISL 3-7A (DE 408) commands received at 3-F35-2	4.5
228							413		3-F35-2	Dec 08 2015	15	51	33.013289	OSCILLOGRAPHY TRIG'D		3-F35-2	OSCILLOGRAPHY TRIG'D verified	4.5
227							414		3-F35-2	Dec 08 2015	15	51	33.013289	Trip 3-7A	On (CO2)	3-F35-2	Trip 3-7A (DE 414) Contact Output Asserted 2ms after SYS ISL3-7A (DE 408) command received at 3-F35-2	4.5
226							415		3-F35-2	Dec 08 2015	15	51	33.013289	Trip 3-13A	On (CO6)	3-F35-2	Trip 3-13A (DE 415) Contact Output Asserted 2ms after SYS ISL3-13A (DE 409) command received at 3-F35-2	4.5
225							416		3-F35-2	Dec 08 2015	15	51	33.013289	Shed 72-5A	On (RI5)	C90P	All SHED commands from C90P detected at 3-F35-2 (DE 416-419) 2ms after initial SYS ISL3-13A (DE 409) and SYS ISL3-7A (DE 408) command received.	4.5
224							417		3-F35-2	Dec 08 2015	15	51	33.013289	Shed 72-21A	On (RI12)	C90P		4.5
223							418		3-F35-2	Dec 08 2015	15	51	33.013289	Shed 72-25A	On (RI15)	C90P		4.5
222							419		3-F35-2	Dec 08 2015	15	51	33.013289	Shed 3-6A	On (RI23)	C90P		4.5
221				425					72-F35-3	Dec 08 2015	15	51	33.013986	FAULT RPT TRIG		72-F35-3	FAULT RPT TRIG (DE 425) by Shed 72-21A (DE 422) command received at 72-F35-3	5.2
220				426					72-F35-3	Dec 08 2015	15	51	33.013986	Trip 72-21A	On (CO9)	72-F35-3	Trip 72-21A (DE 426) Contact Output Asserted 2ms after Shed 72-21A (DE 422) command received at 72-F35-3	5.2
219		322							72-F35-1	Dec 08 2015	15	51	33.014105	Osc Trigger	On (VO64)	C90P	OSC Trigger (DE 322) by Shed 72-5A (DE 318) command received at 72-F35-1	5.3
218		323							72-F35-1	Dec 08 2015	15	51	33.014105	OSCILLOGRAPHY TRIG'D		72-F35-1	OSCILLOGRAPHY TRIG'D verified	5.3
217		324							72-F35-1	Dec 08 2015	15	51	33.014105	Trip 72-5A	On (CO9)	72-F35-1	Trip 72-5A (DE 324) Contact Output Asserted 2ms after Shed 72-5A (DE 318) command received at 72-F35-1. Breaker 72-5A was open for Live Event #1. However, the Breaker was assigned a Priority and the Trip Circuit was not disabled. Tripping of 72-5A shed 0kW of load.	5.3
216					290				72-F35-4	Dec 08 2015	15	51	33.014193	Osc Trigger	On (VO64)	C90P	OSC Trigger (DE 290) by Shed 72-25A (DE 288) command received at 72-F35-4	5.4
215					291				72-F35-4	Dec 08 2015	15	51	33.014193	OSCILLOGRAPHY TRIG'D		72-F35-4	OSCILLOGRAPHY TRIG'D verified	5.4
214					292				72-F35-4	Dec 08 2015	15	51	33.013986	Trip 72-25A	On (CO5)	72-F35-4	Trip 72-25A (DE 292) Contact Output Asserted 2ms after Shed 72-25A (DE 288) command received at 72-F35-4	5.2
213							420		3-F35-2	Dec 08 2015	15	51	33.015370	FAULT RPT TRIG		3-F35-2	FAULT RPT TRIG (DE 420) by Shed 3-6A (DE 419) command received at 3-F35-2	6.6
212							421		3-F35-2	Dec 08 2015	15	51	33.015370	Trip 3-6A	On (CO1)	3-F35-2	The logging of the OPN status of the breakers was not enabled in 3-F35-2. 3-6A-OPN status is based upon Waveform data. The ON status ('b' switch closed) is asserted at ~47.9ms after Shed 3-6A (DE 419) command and ~45.8ms after Trip 3-6A (DE 421) asserted in 3-F35-2.	6.6
211			423						72-F35-2	Dec 08 2015	15	51	33.038937	72-8A-OPN	On (CI2)	72-F35-2	72-8A-OPN (DE 423) On status ('b' switch closed) asserted 28.9 ms after SYS ISL72-8A (DE 410) command and 26.8 ms after Trip 72-8A (DE 417) asserted in 72-F35-2. Power Plant LOOP Feeder to Franklin Substation disconnected by OPEN Breaker 72-8A to Breaker F-6A	30.1
210				427					72-F35-3	Dec 08 2015	15	51	33.039385	72-18-OPN	On (CI4)	72-F35-3	72-18A-OPN (DE 427) ON status ('b' switch closed) asserted 29.6 ms after SYS ISL72-18A (DE 414) command and 27.5ms after Trip 72-18A (DE 420) asserted in 72-F35-3. Power Plant LOOP Feeder to Substation 2 disconnected by OPEN Breaker 72-18A to Breaker 2-14A	30.6
209									72-F35-4	Dec 08 2015	15	51	33.042360	72-25A-OPN	On (CI3)	72-F35-4	72-25A-OPN (DE 293) On status ('b' switch closed) asserted 30.3ms after Shed 72-25A (DE 410) command and 28.4ms after Trip 72-25A (DE 292) asserted in 72-F35-2. Tripping of 72-25A shed 528kw of load.	33.6
208									72-F35-3	Dec 08 2015	15	51	33.042385	72-17A-OPN	On (CI3)	72-F35-3	72-17A-OPN (DE 428) ON status ('b' switch closed) asserted 32.6ms after SYS ISL72-17A (DE 413) command and 30.5ms after Trip 72-17A (DE 428) asserted in 72-F35-3. Power Plant to Franklin Annex LOOP Feeder disconnected by OPEN Breaker 72-17A to Breaker F-15A	33.6

HMI EVENT LOG: LIVE EVENT #1 - SINGLE GTG (Summer Operation) - December 8, 2015

DEVICE EVENT NUMBER																Initiating Device	Comments	Absolute Time (ms) of Event
HMI	F-35-1	72-F35-1	72-F35-2	72-F35-3	72-F35-4	3-F35-1	3-F35-2	3-F35-3	Device	Date	Hour	Minute	Seconds	Cause	State (Source)			
207			429						72-F35-3	Dec 08 2015	15	51	33.043392	72-21A-OPN	On (CI5)	72-F35-3	72-21A-OPN (DE 429) ON status ('b' switch closed) asserted 31.4 ms after Shed 72-21A (DE 422) command and 29.4ms after Trip 72-21A (DE 426) asserted in 72-F35-3. Tripping of 72-21A shed 66kW of load.	34.6
206			424						72-F35-2	Dec 08 2015	15	51	33.044937	72-9A-OPN	On (CI3)	72-F35-2	72-9A ON status ('b' switch) Verified 34.9 ms after SYS ISL72-9A (DE 4110 command and 32.9ms after Trip 72-9A (DE 418) asserted in 72-F35-2. Power Plant LOOP Feeder to Substation 2 disconnected by OPEN Breaker 72-9A to breaker 2-6A.	36.1
							Wave		3-F35-2	Dec 08 2015	15	51	33.051312	3-13A-OPN	On	3-F35-2	3-13A-OPN status is based upon Waveform data. The logging of the OPN status was not enabled in 3-F35-2. The ON status ('b' switch closed) is asserted at ~40.1ms after SYS ISL3-13A (DE 409) command and 38.0ms after Trip 3-13A (DE 414) asserted in 3-F35-2. Substation 3 to Franklin Annex LOOP Feeder disconnected by OPEN Breaker 3-13A to Breaker F-14A.	42.5
							Wave		3-F35-2	Dec 08 2015	15	51	33.058615	3-7A-OPN	On	3-F35-2	The logging of the OPN status was not enabled in 3-F35-2. 3-7A-OPN status is based upon Waveform data. The ON status ('b' switch closed) is asserted at ~47.4ms after SYS ISL3-7A (DE 408) command and 45.3ms after Trip 3-7A (DE 408) asserted in 3-F35-2. Substation 3 to Franklin LOOP Feeder disconnected by OPEN Breaker 3-7A to Breaker F-4A.	49.8
							Wave		3-F35-2	Dec 08 2015	15	51	33.061209	3-6A-OPN	On	3-F35-2	The logging of the OPN status of the breakers was not enabled in 3-F35-2. 3-6A-OPN status is based upon Waveform data. The ON status ('b' switch closed) is asserted at ~47.9ms after Shed 3-6A (DE 419) command and ~45.8ms after Trip 3-6A (DE 421) asserted in 3-F35-2. Tripping of 3-6A shed 599kW of load.	52.4
205					294				72-F35-4	Dec 08 2015	15	51	57.945143	DG2-27A-OPN	Off (CI5)	72-F35-4	DG #2 automatically started & synchronized 25 seconds after detection of Loss of Utility by DCS to facilitate load restoration by PNS.	24.9
204					295				72-F35-4	Dec 08 2015	15	52	13.319978	DG1-26A-OPN	Off (CI4)	72-F35-4	DG #1 automatically started & synchronized 40 seconds after detection of Loss of Utility by DCS to facilitate load restoration by PNS.	40.3
203									C90P	Dec 08 2015	15	53	33.013889	Reset		C90P	C90P RESET by internal setting. C90P Contingency Timer set for 120 seconds following initiation of FLS event. Event not logged, but reset of Shed commands started at 15:53:33.013889	120.0

Note: The Elapsed Time after Utility Unavailable for HMI DE 205, 204, and 203 is expressed as seconds.

HMI EVENT LOG - LIVE EVENT #2 - TWO GTG (Winter Operation) - December 8, 2015

DEVICE EVENT NUMBER												Device	Date	Hour	Minute	Seconds	Cause	State (Source)	Initiating Device	Comments	Absolute Time in ms of Event
HMI	F-F35-1	72-F35-1	72-F35-2	72-F35-3	72-F35-4	72-F35-5	72-F35-6	72-F35-7	72-F35-8	72-F35-9	72-F35-10										
98												72-F35-3	Dec 08 2015	17	38	45.344386	LS Running	On (R29)	HMI	LIVE TEST #1 FLS ENABLED by HMI in C90P and Verified in 72-F35-3	
97			443									72-F35-2	Dec 08 2015	17	38	45.344429	LS Running	On (R29)	HMI	LIVE TEST #1 FLS ENABLED by HMI in C90P and Verified in 72-F35-2	
96												72-F35-4	Dec 08 2015	17	38	45.344622	LS Running	On (R29)	HMI	LIVE TEST #1 FLS ENABLED by HMI in C90P and Verified in 72-F35-4	
95		335										72-F35-1	Dec 08 2015	17	38	45.344955	LS Running	On (R29)	HMI	LIVE TEST #1 FLS ENABLED by HMI in C90P and Verified in 72-F35-1	
94												3-F35-1	Dec 08 2015	17	38	45.345252	LS Running	On (R29)	HMI	LIVE TEST #1 FLS ENABLED by HMI in C90P and Verified in 3-F35-1	
93												3-F35-3	Dec 08 2015	17	38	45.345548	LS Running	On (R29)	HMI	LIVE TEST #1 FLS ENABLED by HMI in C90P and Verified in 3-F35-3	
92	471											F-F35-1	Dec 08 2015	17	38	45.345631	LS Running	On (R29)	HMI	LIVE TEST #1 FLS ENABLED by HMI in C90P and Verified in F-F35-1	
91												3-F35-2	Dec 08 2015	17	38	45.345746	LS Running	On (R29)	HMI	LIVE TEST #1 FLS ENABLED by HMI in C90P and Verified in 3-F35-2	
90												72-F35-3	Dec 08 2015	17	38	45.394393	LS Normal	On (R30)	C90P	LIVE TEST #1 FLS STATUS Verified in 72-F35-3	
89												72-F35-2	Dec 08 2015	17	38	45.394436	LS Normal	On (R30)	C90P	LIVE TEST #1 FLS STATUS Verified in 72-F35-2	
88												72-F35-4	Dec 08 2015	17	38	45.394631	LS Normal	On (R30)	C90P	LIVE TEST #1 FLS STATUS Verified in 72-F35-4	
87		336										72-F35-1	Dec 08 2015	17	38	45.394965	LS Normal	On (R30)	C90P	LIVE TEST #1 FLS STATUS Verified in 72-F35-1	
86												3-F35-1	Dec 08 2015	17	38	45.395260	LS Normal	On (R30)	C90P	LIVE TEST #1 FLS STATUS Verified in 3-F35-1	
85	85											3-F35-3	Dec 08 2015	17	38	45.395556	LS Normal	On (R30)	C90P	LIVE TEST #1 FLS STATUS Verified in 3-F35-3	
84	472											F-F35-1	Dec 08 2015	17	38	45.395940	LS Normal	On (R30)	C90P	LIVE TEST #1 FLS STATUS Verified in F-F35-1	
83												3-F35-2	Dec 08 2015	17	38	45.395756	LS Normal	On (R30)	C90P	LIVE TEST #1 FLS STATUS Verified in 3-F35-2	
FLS ENABLED FOR LIVE TEST #2																				FLS ENABLED FOR LIVE TEST #2	ELAPSED TIME (Milliseconds)
CALCULATED EVENT START TIME												F-F35-1	Dec 08 2015	17	41	57.140574			CALC	ESTIMATED EVENT START TIME= UTILITY UNAVAILABLE Time - (F1 Time of Opening); Where F1 Time of Opening = F1'b closed = Aux Relay 32ms delay+ 2ms F35 Debounce Time) = 34ms	-34.0
CALCULATED UTILITY UNAVAILABLE TIME												F-F35-1	Dec 08 2015	17	41	57.174574	UTILITY UNAVAILABLE		CALC	ESTIMATED UTILITY UNAVAILABLE Time = (Osc Trigger On (VO64) Time - 2ms (arbitrary as this event was not Enabled in F-F35-1)	0.0
82			445									72-F35-2	Dec 08 2015	17	41	57.175494	SYS ISL72-8A	On (R17)	C90P	C90P receives UTILITY UNAVAILABLE GOOSE message from F-F35-1 and C90P sends SYS ISL72-8A (DE 445) command to 72-F35-2 to open Loop Feeder Breaker 72-8A at Power Plant to Franklin Breaker F-8A.	0.9
81												72-F35-2	Dec 08 2015	17	41	57.175494	SYS ISL72-9A	On (R18)	C90P	C90P receives UTILITY UNAVAILABLE GOOSE message from F-F35-1 and C90P sends SYS ISL72-9A (DE 446) command to 72-F35-2 to open Loop Feeder Breaker 72-9A at Power Plant to Substation 2 Breaker 2-6A.	0.9
80												72-F35-3	Dec 08 2015	17	41	57.175575	SYS IS72-17A	On (R10)	C90P	C90P receives UTILITY UNAVAILABLE GOOSE message from F-F35-1 and C90P sends SYS ISL72-17A (DE 451) command to 72-F35-3 to open Loop Feeder Breaker 72-17A at Power Plant to Franklin Annex Breaker F-15A.	1.0
79												72-F35-3	Dec 08 2015	17	41	57.175575	SYS ISL72-18A	On (R11)	C90P	C90P receives UTILITY UNAVAILABLE GOOSE message from F-F35-1 and C90P sends SYS ISL72-18A (DE 452) command to 72-F35-3 to open Loop Feeder Breaker 72-18A at Power Plant to Substation 2 Breaker 2-14A.	1.0
78	473											72-F35-2	Dec 08 2015	17	41	57.176574	Osc Trigger	On (VO64)	F1	Oscillography Trigger asserted in F-F35-1 by directly detecting UTILITY UNAVAILABLE (monitoring of status of F1 & F12).	2.0
77	474											72-F35-2	Dec 08 2015	17	41	57.176574	OSCILLOGRAPHY TRIG'D	72-F35-2	72-F35-2	OSCILLOGRAPHY TRIG'D verified	2.0
76												3-F35-2	Dec 08 2015	17	41	57.176736	SYS ISL 3-7A	On (R124)	C90P	C90P receives UTILITY UNAVAILABLE GOOSE message from F-F35-1 and C90P sends SYS ISL command to 3-F35-2 (DE 438) to open Loop Feeder Breaker 3-7A at Substation 3 to Franklin Breaker F-4A.	2.2
75												3-F35-2	Dec 08 2015	17	41	57.176736	SYS ISL3-13A	On (R125)	C90P	C90P receives UTILITY UNAVAILABLE message from F-F35-1 and C90P sends SYS ISL command to 3-F35-2 (DE 409) to open Loop Feeder Breaker 3-13A at Substation 3 to Franklin Annex Breaker F-14A.	2.2
74												72-F35-2	Dec 08 2015	17	41	57.177589	FAULT RPT TRIG		72-F35-2	FAULT RPT TRIG (DE 447) by SYS ISL72-9A (DE 445) command Received at 72-F35-2	3.0
73												72-F35-2	Dec 08 2015	17	41	57.177589	FAULT RPT TRIG		72-F35-2	FAULT RPT TRIG (DE 448) by SYS ISL72-9A (DE 446) command Received at 72-F35-2	3.0
72												72-F35-2	Dec 08 2015	17	41	57.177589	FAULT RPT TRIG		72-F35-2	FAULT RPT TRIG (DE 449) by unknown	3.0
71												72-F35-2	Dec 08 2015	17	41	57.177589	Osc Trigger	On (VO64)	72-F35-2	OSC Trigger (DE450) by SYS ISL72-9A (DE445) & Sys ISL72-9A (DE446) commands received at 72-F35-2	3.0
70												72-F35-2	Dec 08 2015	17	41	57.177589	OSCILLOGRAPHY TRIG'D	72-F35-2	72-F35-2	OSCILLOGRAPHY TRIG'D verified	3.0
69												72-F35-2	Dec 08 2015	17	41	57.177589	Trip 72-8A	On (CO2)	72-F35-2	Trip 72-8A (DE452) Contact Output Asserted 2ms after SYS ISL72-8A (DE 445) command received at 72-F35-2	3.0
68												72-F35-2	Dec 08 2015	17	41	57.177589	Trip 72-9A	On (CO5)	72-F35-2	Trip 72-9A (DE453) Contact Output Asserted 2ms after SYS ISL72-9A (DE 446) command received at 72-F35-2	3.0
67												72-F35-3	Dec 08 2015	17	41	57.177663	FAULT RPT TRIG		72-F35-3	FAULT RPT TRIG (DE 453) by SYS ISL72-17A (DE 451) command received at 72-F35-3	3.1
66												72-F35-3	Dec 08 2015	17	41	57.177663	FAULT RPT TRIG		72-F35-3	FAULT RPT TRIG (DE416) by SYS ISL72-18A (DE 452) command received at 72-F35-3	3.1

HMI EVENT LOG - LIVE EVENT #2 - TWO GTG (Winter Operation) - December 8, 2015

DEVICE EVENT NUMBER													Device	Date	Hour	Minute	Seconds	Cause	State (Source)	Initiating Device	Comments	Absolute Time in ms of Event
HMI	F-F35-1	72-F35-1	72-F35-2	72-F35-3	72-F35-4	72-F35-5	72-F35-6	72-F35-7	72-F35-8	72-F35-9	72-F35-10	72-F35-11										
65				455									72-F35-3	Dec 08 2015	17	41	57.177663	Osc Trigger	On (VO64)	72-F35-3	OSC Trigger (DE 455) by SYS ISL72-17A (DE451) & SYS ISL72-18A (DE452) commands received at 72-F35-3	3.1
64				456									72-F35-3	Dec 08 2015	17	41	57.177663	OSCILLOGRAPHY TRIG'D	On (CO5)	72-F35-3	OSCILLOGRAPHY TRIG'D verified	3.1
63				457									72-F35-3	Dec 08 2015	17	41	57.177663	Trip 72-17A	On (CO5)	72-F35-3	Trip 72-17A (DE 457) Contact Output Asserted 2ms after SYS ISL72-17A (DE 451) command received at 72-F35-3	3.1
62				458									72-F35-3	Dec 08 2015	17	41	57.177663	Trip 72-18A	On (CO6)	72-F35-3	Trip 72-18A (DE 458) Contact Output Asserted 2ms after SYS ISL72-18A (DE452) command received at 72-F35-3	3.1
61	475												F-F35-1	Dec 08 2015	17	41	57.178658	Trip F-5	On (CO1)	C90P	Trip F-5 (DE 475) Contact Output Asserted 4ms after F-5 LS REQ (VO1) request sent from F-F35-1 to C90P (No DE - Event logging not enabled for LS REQ)	4.1
60	476												F-F35-1	Dec 08 2015	17	41	57.178658	Trip F-9	On (CO2)	C90P	Trip F-9 (DE 476) Contact Output Asserted 4ms after F-9 LS REQ (VO2) request sent from F-F35-1 to C90P (No DE - Event logging not enabled for LS REQ)	4.1
59	477												F-F35-1	Dec 08 2015	17	41	57.178658	Trip F-10	On (CO5)	C90P	Trip F-10 (DE 477) Contact Output Asserted 4ms after F-10 LS REQ (VO3) request sent from F-F35-1 to C90P (No DE-Event logging not enabled for LS REQ)	4.1
58													3-F35-2	Dec 08 2015	17	41	57.178821	FAULT RPT TRIG		72-F35-2	FAULT RPT TRIG (DE 440) by SYS ISL 3-7A (DE 438) command received at 3-F35-2	4.2
57													3-F35-2	Dec 08 2015	17	41	57.178821	FAULT RPT TRIG		72-F35-2	FAULT RPT TRIG (DE 441) by SYS ISL 3-13A (DE 439) command received at 3-F35-2	4.2
56													3-F35-2	Dec 08 2015	17	41	57.178821	Osc Trigger	On (VO64)	72-F35-2	OSC Trigger (DE 442) by SYS ISL 3-13A (DE 439) & Sys ISL 3-7A (DE 438) commands received at 3-F35-2	4.2
55													3-F35-2	Dec 08 2015	17	41	57.178821	OSCILLOGRAPHY TRIG'D	On (VO64)	72-F35-2	OSCILLOGRAPHY TRIG'D verified	4.2
54													3-F35-2	Dec 08 2015	17	41	57.178821	Trip 3-7A	On (CO2)	72-F35-2	Trip 3-7A (DE 444) Contact Output Asserted 2ms after SYS ISL3-7A (DE 438) command received at 3-F35-2	4.2
53													3-F35-2	Dec 08 2015	17	41	57.178821	Trip 3-13A	On (CO6)	72-F35-2	Trip 3-13A (DE 445) Contact Output Asserted 2ms after SYS ISL3-13A (DE 439) command received at 3-F35-2	4.2
52			454										72-F35-2	Dec 08 2015	17	41	57.202742	72-8A-OPN	On (CI2)	72-F35-2	72-8A-OPN (DE 454) On status ('b' switch closed) asserted 28.9 ms after SYS ISL72-8A (DE 445) command and 26.8ms after Trip 72-8A (DE 452) asserted in 72-F35-2. Power Plant LOOP Feeder to Franklin Substation disconnected by OPEN Breaker 72-8A to Breaker F-6A	28.2
51				459									72-F35-3	Dec 08 2015	17	41	57.204011	72-18-OPN	On (CI4)	72-F35-3	72-18A-OPN (DE 459) ON status ('b' switch closed) asserted 29.6 ms after SYS ISL72-18A (DE 452) command and 27.5ms after Trip 72-18A (DE 458) asserted in 72-F35-3. Power Plant LOOP Feeder to Substation 2 disconnected by OPEN Breaker 72-18A to Breaker 2-14A	29.4
50				460									72-F35-3	Dec 08 2015	17	41	57.206011	72-17A-OPN	On (CI3)	72-F35-3	72-17A-OPN (DE 460) ON status ('b' switch closed) asserted 32.6ms after SYS ISL72-17A (DE 451) command and 30.5ms after Trip 72-17A (DE 459) asserted in 72-F35-3. Power Plant to Franklin Annex LOOP Feeder disconnected by OPEN Breaker 72-17A to Breaker F-15A	31.4
49			455										72-F35-2	Dec 08 2015	17	41	57.206725	72-9A-OPN	On (CI3)	72-F35-2	72-9A ON status ('b' switch) Verified 34.9 ms after SYS ISL72-9A (DE-448) command and 32.9ms after Trip-9A (DE 453) asserted in 72-F35-2. Power Plant LOOP Feeder to Substation 2 disconnected by OPEN Breaker 72-9A to Breaker 2-6A.	32.2
WF													3-F35-2	Dec 08 2015	17	41	57.217039	3-13A-OPN	On	3-F35-2	The logging of the OPN status was not enabled in 3-F35-2. 3-13A-OPN status is based upon Waveform data. The ON status ('b' switch closed) is asserted at ~40.3ms after SYS ISL3-13A (DE 439) command and 38.2ms after Trip 3-13A (DE 445) asserted in 3-F35-2. Substation 3 to Franklin Annex LOOP Feeder disconnected by OPEN Breaker 3-13A to Breaker F-14A.	42.5
WF													3-F35-2	Dec 08 2015	17	41	57.222067	3-7A-OPN	On	3-F35-2	The logging of the OPN status was not enabled in 3-F35-2. 3-7A-OPN status is based upon Waveform data. The ON status ('b' switch closed) is asserted at ~45.3ms after SYS ISL3-7A (DE 438) command and 43.2ms after Trip 3-7A (DE 444) asserted in 3-F35-2. Substation 3 to Franklin LOOP Feeder disconnected by OPEN Breaker 3-7A to Breaker F-4A.	47.5
48					313								72-F35-4	Dec 08 2015	17	42	18.08431	DG2-27A-OPN	Off (CI5)	DCS	DG #2 automatically started & synchronized 21 seconds after detection of Loss of Utility by DCS to facilitate load restoration by PNS.	20.9
47					314								72-F35-4	Dec 08 2015	17	42	27.663894	DG1-26A-OPN	Off (CI4)	DCS	DG #1 automatically started & synchronized 31 seconds after detection of Loss of Utility by DCS to facilitate load restoration by PNS.	30.5

Note: The absolute time after Utility Unavailable for HMI DE 48 & 47, is expressed as seconds.

HMI Site Event Recorder // PSNS-MicroGrid

System Date/Time Updated: Events 319 - 304

System Reset: Events 303 - 301

Live Test #1: Events 300 - 204

System Reset: Events 203 - 99

Live Test #2: Events 98 - 47

System Reset: Events 46 - 1

#,Device,Event Number,Time Stamp,Cause

1, 72-F35-2, 466, Dec 08 2015 18:27:19.555631, Trip 72-9A Off (CO5)
2, 72-F35-2, 465, Dec 08 2015 18:27:17.046296, Trip 72-8A Off (CO2)
3, 72-F35-2, 464, Dec 08 2015 18:27:17.046296, Osc Trigger Off (VO64)
4, 72-F35-3, 471, Dec 08 2015 18:27:11.555934, Trip 72-18A Off (CO6)
5, 72-F35-3, 470, Dec 08 2015 18:27:09.086089, Trip 72-17A Off (CO5)
6, 72-F35-3, 469, Dec 08 2015 18:27:09.086089, Osc Trigger Off (VO64)
7, 3-F35-2, 452, Dec 08 2015 18:26:58.025569, Trip 3-13A Off (CO6)
8, 3-F35-2, 451, Dec 08 2015 18:26:55.745121, Trip 3-7A Off (CO2)
9, 3-F35-2, 450, Dec 08 2015 18:26:55.745121, Osc Trigger Off (VO64)
10, F-F35-1, 483, Dec 08 2015 18:26:41.615850, Trip F-10 Off (CO5)
11, F-F35-1, 482, Dec 08 2015 18:26:38.775147, Trip F-9 Off (CO2)
12, 72-F35-1, 339, Dec 08 2015 18:25:17.670461, 72-3A-OPN Off (CI3)
13, 72-F35-2, 463, Dec 08 2015 18:09:47.204416, 72-9A-OPN Off (CI3)
14, 72-F35-3, 468, Dec 08 2015 18:09:08.311929, 72-18-OPN Off (CI4)
15, 72-F35-3, 467, Dec 08 2015 18:09:08.299428, 72-18-OPN On (CI4)
16, 72-F35-3, 466, Dec 08 2015 18:09:08.251941, 72-18-OPN Off (CI4)
17, 72-F35-4, 318, Dec 08 2015 18:04:32.586968, DG1-26A-OPN On (CI4)
18, 72-F35-4, 317, Dec 08 2015 18:04:32.125445, DG2-27A-OPN On (CI5)
19, 72-F35-3, 465, Dec 08 2015 17:55:27.523287, 72-17A-OPN Off (CI3)
20, F-F35-1, 481, Dec 08 2015 17:54:56.182284, Trip F-5 Off (CO1)
21, F-F35-1, 480, Dec 08 2015 17:54:56.182284, Osc Trigger Off (VO64)
22, 72-F35-2, 462, Dec 08 2015 17:53:56.942239, 72-8A-OPN Off (CI2)
23, 72-F35-2, 461, Dec 08 2015 17:53:56.928238, 72-8A-OPN On (CI2)
24, 72-F35-2, 460, Dec 08 2015 17:53:56.878736, 72-8A-OPN Off (CI2)
25, F-F35-1, 479, Dec 08 2015 17:50:03.132004, LS Normal Off (RI30)
26, 3-F35-3, 289, Dec 08 2015 17:50:03.131274, LS Normal Off (RI30)
27, 3-F35-2, 449, Dec 08 2015 17:50:03.130889, LS Normal Off (RI30)
28, 3-F35-1, 285, Dec 08 2015 17:50:03.130397, LS Normal Off (RI30)
29, 72-F35-1, 338, Dec 08 2015 17:50:03.130326, LS Normal Off (RI30)
30, 72-F35-4, 316, Dec 08 2015 17:50:03.129818, LS Normal Off (RI30)
31, 72-F35-2, 459, Dec 08 2015 17:50:03.129750, LS Normal Off (RI30)
32, 72-F35-3, 464, Dec 08 2015 17:50:03.129673, LS Normal Off (RI30)
33, 3-F35-2, 448, Dec 08 2015 17:50:03.082991, SYS ISL3-13A Off (RI25)
34, 3-F35-2, 447, Dec 08 2015 17:50:03.082991, SYS ISL 3-7A Off (RI24)
35, F-F35-1, 478, Dec 08 2015 17:50:03.081995, LS Running Off (RI29)
36, 72-F35-2, 458, Dec 08 2015 17:50:03.081849, SYS ISL72-9A Off (RI8)
37, 72-F35-2, 457, Dec 08 2015 17:50:03.081849, SYS ISL72-8A Off (RI7)
38, 72-F35-3, 463, Dec 08 2015 17:50:03.081774, SYS ISL72-18A Off (RI11)
39, 72-F35-3, 462, Dec 08 2015 17:50:03.081774, SYS IS72-17A Off (RI10)
40, 3-F35-3, 288, Dec 08 2015 17:50:03.081282, LS Running Off (RI29)
41, 3-F35-2, 446, Dec 08 2015 17:50:03.080903, LS Running Off (RI29)

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42, 3-F35-1, 284, Dec 08 2015 17:50:03.080411, LS Running Off (RI29)
 43, 72-F35-1, 337, Dec 08 2015 17:50:03.080337, LS Running Off (RI29)
 44, 72-F35-4, 315, Dec 08 2015 17:50:03.079832, LS Running Off (RI29)
 45, 72-F35-2, 456, Dec 08 2015 17:50:03.079765, LS Running Off (RI29)
 46, 72-F35-3, 461, Dec 08 2015 17:50:03.079689, LS Running Off (RI29)
 47, 72-F35-4, 314, Dec 08 2015 17:42:27.663894, DG1-26A-OPN Off (CI4)
 48, 72-F35-4, 313, Dec 08 2015 17:42:18.068431, DG2-27A-OPN Off (CI5)
 49, 72-F35-2, 455, Dec 08 2015 17:41:57.206725, 72-9A-OPN On (CI3)
 50, 72-F35-3, 460, Dec 08 2015 17:41:57.206011, 72-17A-OPN On (CI3)
 51, 72-F35-3, 459, Dec 08 2015 17:41:57.204011, 72-18-OPN On (CI4)
 52, 72-F35-2, 454, Dec 08 2015 17:41:57.202742, 72-8A-OPN On (CI2)
 53, 3-F35-2, 445, Dec 08 2015 17:41:57.178821, Trip 3-13A On (CO6)
 54, 3-F35-2, 444, Dec 08 2015 17:41:57.178821, Trip 3-7A On (CO2)
 55, 3-F35-2, 443, Dec 08 2015 17:41:57.178821, OSCILLOGRAPHY TRIG'D
 56, 3-F35-2, 442, Dec 08 2015 17:41:57.178821, Osc Trigger On (VO64)
 57, 3-F35-2, 441, Dec 08 2015 17:41:57.178821, FAULT RPT TRIG
 58, 3-F35-2, 440, Dec 08 2015 17:41:57.178821, FAULT RPT TRIG
 59, F-F35-1, 477, Dec 08 2015 17:41:57.178658, Trip F-10 On (CO5)
 60, F-F35-1, 476, Dec 08 2015 17:41:57.178658, Trip F-9 On (CO2)
 61, F-F35-1, 475, Dec 08 2015 17:41:57.178658, Trip F-5 On (CO1)
 62, 72-F35-3, 458, Dec 08 2015 17:41:57.177663, Trip 72-18A On (CO6)
 63, 72-F35-3, 457, Dec 08 2015 17:41:57.177663, Trip 72-17A On (CO5)
 64, 72-F35-3, 456, Dec 08 2015 17:41:57.177663, OSCILLOGRAPHY TRIG'D
 65, 72-F35-3, 455, Dec 08 2015 17:41:57.177663, Osc Trigger On (VO64)
 66, 72-F35-3, 454, Dec 08 2015 17:41:57.177663, FAULT RPT TRIG
 67, 72-F35-3, 453, Dec 08 2015 17:41:57.177663, FAULT RPT TRIG
 68, 72-F35-2, 453, Dec 08 2015 17:41:57.177589, Trip 72-9A On (CO5)
 69, 72-F35-2, 452, Dec 08 2015 17:41:57.177589, Trip 72-8A On (CO2)
 70, 72-F35-2, 451, Dec 08 2015 17:41:57.177589, OSCILLOGRAPHY TRIG'D
 71, 72-F35-2, 450, Dec 08 2015 17:41:57.177589, Osc Trigger On (VO64)
 72, 72-F35-2, 449, Dec 08 2015 17:41:57.177589, FAULT RPT TRIG
 73, 72-F35-2, 448, Dec 08 2015 17:41:57.177589, FAULT RPT TRIG
 74, 72-F35-2, 447, Dec 08 2015 17:41:57.177589, FAULT RPT TRIG
 75, 3-F35-2, 439, Dec 08 2015 17:41:57.176736, SYS ISL3-13A On (RI25)
 76, 3-F35-2, 438, Dec 08 2015 17:41:57.176736, SYS ISL 3-7A On (RI24)
 77, F-F35-1, 474, Dec 08 2015 17:41:57.176574, OSCILLOGRAPHY TRIG'D
 78, F-F35-1, 473, Dec 08 2015 17:41:57.176574, Osc Trigger On (VO64)
 79, 72-F35-3, 452, Dec 08 2015 17:41:57.175575, SYS ISL72-18A On (RI11)
 80, 72-F35-3, 451, Dec 08 2015 17:41:57.175575, SYS IS72-17A On (RI10)
 81, 72-F35-2, 446, Dec 08 2015 17:41:57.175494, SYS ISL72-9A On (RI8)
 82, 72-F35-2, 445, Dec 08 2015 17:41:57.175494, SYS ISL72-8A On (RI7)
 83, 3-F35-2, 437, Dec 08 2015 17:38:45.395756, LS Normal On (RI30)
 84, F-F35-1, 472, Dec 08 2015 17:38:45.395640, LS Normal On (RI30)
 85, 3-F35-3, 287, Dec 08 2015 17:38:45.395556, LS Normal On (RI30)
 86, 3-F35-1, 283, Dec 08 2015 17:38:45.395260, LS Normal On (RI30)
 87, 72-F35-1, 336, Dec 08 2015 17:38:45.394965, LS Normal On (RI30)
 88, 72-F35-4, 312, Dec 08 2015 17:38:45.394631, LS Normal On (RI30)
 89, 72-F35-2, 444, Dec 08 2015 17:38:45.394436, LS Normal On (RI30)
 90, 72-F35-3, 450, Dec 08 2015 17:38:45.394393, LS Normal On (RI30)
 91, 3-F35-2, 436, Dec 08 2015 17:38:45.345746, LS Running On (RI29)
 92, F-F35-1, 471, Dec 08 2015 17:38:45.345631, LS Running On (RI29)
 93, 3-F35-3, 286, Dec 08 2015 17:38:45.345548, LS Running On (RI29)
 94, 3-F35-1, 282, Dec 08 2015 17:38:45.345252, LS Running On (RI29)

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95, 72-F35-1, 335, Dec 08 2015 17:38:45.344955, LS Running On (RI29)
 96, 72-F35-4, 311, Dec 08 2015 17:38:45.344622, LS Running On (RI29)
 97, 72-F35-2, 443, Dec 08 2015 17:38:45.344429, LS Running On (RI29)
 98, 72-F35-3, 449, Dec 08 2015 17:38:45.344386, LS Running On (RI29)
 99, 72-F35-4, 310, Dec 08 2015 16:58:48.411575, Trip 25A Off (CO5)
 100, 72-F35-4, 309, Dec 08 2015 16:58:48.411575, Osc Trigger Off (VO64)
 101, 72-F35-2, 442, Dec 08 2015 16:58:35.915299, Trip 72-9A Off (CO5)
 102, 72-F35-2, 441, Dec 08 2015 16:58:33.064602, Trip 72-8A Off (CO2)
 103, 72-F35-2, 440, Dec 08 2015 16:58:33.064602, Osc Trigger Off (VO64)
 104, 72-F35-3, 448, Dec 08 2015 16:58:20.893713, Trip 72-21A Off (CO9)
 105, 72-F35-3, 447, Dec 08 2015 16:58:17.822595, Trip 72-18A Off (CO6)
 106, 72-F35-3, 446, Dec 08 2015 16:58:14.603734, Trip 72-17A Off (CO5)
 107, 72-F35-3, 445, Dec 08 2015 16:58:14.603734, Osc Trigger Off (VO64)
 108, 72-F35-1, 334, Dec 08 2015 16:58:05.253582, Trip 72-5A Off (CO9)
 109, 72-F35-1, 333, Dec 08 2015 16:58:05.253582, Osc Trigger Off (VO64)
 110, 3-F35-2, 435, Dec 08 2015 16:57:41.800748, Trip 3-13A Off (CO6)
 111, 3-F35-2, 434, Dec 08 2015 16:57:37.881479, Trip 3-7A Off (CO2)
 112, 3-F35-2, 433, Dec 08 2015 16:57:33.941189, Trip 3-6A Off (CO1)
 113, 3-F35-2, 432, Dec 08 2015 16:57:33.941189, Osc Trigger Off (VO64)
 114, 72-F35-2, 439, Dec 08 2015 16:49:31.066095, GTG2-10A-OPN Off (CI4)
 115, 72-F35-3, 444, Dec 08 2015 16:32:49.005889, 72-21A-OPN Off (CI5)
 116, 72-F35-4, 308, Dec 08 2015 16:32:27.576327, 72-25A-OPN Off (CI3)
 117, 72-F35-4, 307, Dec 08 2015 16:32:27.567826, 72-25A-OPN On (CI3)
 118, 72-F35-4, 306, Dec 08 2015 16:32:27.516322, 72-25A-OPN Off (CI3)
 119, F-F35-1, 470, Dec 08 2015 16:28:43.354116, Trip F-10 Off (CO5)
 120, F-F35-1, 469, Dec 08 2015 16:28:40.911906, Trip F-9 Off (CO2)
 121, F-F35-1, 468, Dec 08 2015 16:28:38.192715, Trip F-5 Off (CO1)
 122, F-F35-1, 467, Dec 08 2015 16:28:38.192715, Osc Trigger Off (VO64)
 123, 72-F35-2, 438, Dec 08 2015 16:24:44.493624, 72-9A-OPN Off (CI3)
 124, 72-F35-3, 443, Dec 08 2015 16:24:19.960419, 72-18-OPN Off (CI4)
 125, 72-F35-3, 442, Dec 08 2015 16:24:19.949419, 72-18-OPN On (CI4)
 126, 72-F35-3, 441, Dec 08 2015 16:24:19.899915, 72-18-OPN Off (CI4)
 127, 72-F35-4, 305, Dec 08 2015 16:15:47.084329, DG1-26A-OPN On (CI4)
 128, 72-F35-4, 304, Dec 08 2015 16:15:46.660809, DG2-27A-OPN On (CI5)
 129, 72-F35-3, 440, Dec 08 2015 16:07:36.179428, 72-17A-OPN Off (CI3)
 130, 72-F35-2, 437, Dec 08 2015 16:06:55.601190, 72-8A-OPN Off (CI2)
 131, 72-F35-2, 436, Dec 08 2015 16:06:55.586688, 72-8A-OPN On (CI2)
 132, 72-F35-2, 435, Dec 08 2015 16:06:55.537186, 72-8A-OPN Off (CI2)
 133, F-F35-1, 466, Dec 08 2015 15:56:41.812262, LS Normal Off (RI30)
 134, 3-F35-3, 285, Dec 08 2015 15:56:41.812212, LS Normal Off (RI30)
 135, 3-F35-2, 431, Dec 08 2015 15:56:41.812039, LS Normal Off (RI30)
 136, 3-F35-1, 281, Dec 08 2015 15:56:41.811659, LS Normal Off (RI30)
 137, 72-F35-1, 332, Dec 08 2015 15:56:41.811223, LS Normal Off (RI30)
 138, 72-F35-3, 439, Dec 08 2015 15:56:41.811181, LS Normal Off (RI30)
 139, 72-F35-4, 303, Dec 08 2015 15:56:41.811149, LS Normal Off (RI30)
 140, 72-F35-2, 434, Dec 08 2015 15:56:41.811063, LS Normal Off (RI30)
 141, 3-F35-2, 430, Dec 08 2015 15:56:41.764138, SYS ISL3-13A Off (RI25)
 142, 3-F35-2, 429, Dec 08 2015 15:56:41.764138, SYS ISL 3-7A Off (RI24)
 143, 72-F35-3, 438, Dec 08 2015 15:56:41.763277, SYS ISL72-18A Off (RI11)
 144, 72-F35-3, 437, Dec 08 2015 15:56:41.763277, SYS ISL72-17A Off (RI10)
 145, 72-F35-2, 433, Dec 08 2015 15:56:41.763160, SYS ISL72-9A Off (RI8)
 146, 72-F35-2, 432, Dec 08 2015 15:56:41.763160, SYS ISL72-8A Off (RI7)
 147, F-F35-1, 465, Dec 08 2015 15:56:41.762255, LS Running Off (RI29)

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148, 3-F35-3, 284, Dec 08 2015 15:56:41.762225, LS Running Off (RI29)
 149, 3-F35-2, 428, Dec 08 2015 15:56:41.762053, LS Running Off (RI29)
 150, 3-F35-1, 280, Dec 08 2015 15:56:41.761676, LS Running Off (RI29)
 151, 72-F35-1, 331, Dec 08 2015 15:56:41.761231, LS Running Off (RI29)
 152, 72-F35-3, 436, Dec 08 2015 15:56:41.761193, LS Running Off (RI29)
 153, 72-F35-4, 302, Dec 08 2015 15:56:41.761165, LS Running Off (RI29)
 154, 72-F35-2, 431, Dec 08 2015 15:56:41.761076, LS Running Off (RI29)
 155, 3-F35-3, 283, Dec 08 2015 15:56:39.512822, Reset LED Off (RI31)
 156, 3-F35-2, 427, Dec 08 2015 15:56:39.512644, Reset LED Off (RI31)
 157, 3-F35-1, 279, Dec 08 2015 15:56:39.512270, Reset LED Off (RI31)
 158, F-F35-1, 464, Dec 08 2015 15:56:39.512110, Reset LED Off (RI31)
 159, 72-F35-1, 330, Dec 08 2015 15:56:39.511838, Reset LED Off (RI31)
 160, 72-F35-3, 435, Dec 08 2015 15:56:39.511802, Reset LED Off (RI31)
 161, 72-F35-4, 301, Dec 08 2015 15:56:39.511768, Reset LED Off (RI31)
 162, 72-F35-2, 430, Dec 08 2015 15:56:39.511686, Reset LED Off (RI31)
 163, 3-F35-3, 282, Dec 08 2015 15:56:39.362851, Reset LED On (RI31)
 164, 3-F35-2, 426, Dec 08 2015 15:56:39.362677, Reset LED On (RI31)
 165, 3-F35-1, 278, Dec 08 2015 15:56:39.362301, Reset LED On (RI31)
 166, F-F35-1, 463, Dec 08 2015 15:56:39.362106, Reset LED On (RI31)
 167, 72-F35-1, 329, Dec 08 2015 15:56:39.361871, Reset LED On (RI31)
 168, 72-F35-3, 434, Dec 08 2015 15:56:39.361833, Reset LED On (RI31)
 169, 72-F35-4, 300, Dec 08 2015 15:56:39.361800, Reset LED On (RI31)
 170, 72-F35-2, 429, Dec 08 2015 15:56:39.361713, Reset LED On (RI31)
 171, F-F35-1, 462, Dec 08 2015 15:53:33.016165, Shed F5-9-10 Off (RI28)
 172, F-F35-1, 461, Dec 08 2015 15:53:33.016165, Shed 3-6A Off (RI23)
 173, F-F35-1, 460, Dec 08 2015 15:53:33.016165, Shed 72-25A Off (RI15)
 174, F-F35-1, 459, Dec 08 2015 15:53:33.016165, Shed 72-21A Off (RI12)
 175, F-F35-1, 458, Dec 08 2015 15:53:33.016165, Shed 72-5A Off (RI5)
 176, 3-F35-2, 425, Dec 08 2015 15:53:33.014870, Shed 3-6A Off (RI23)
 177, 3-F35-2, 424, Dec 08 2015 15:53:33.014870, Shed 72-25A Off (RI15)
 178, 3-F35-2, 423, Dec 08 2015 15:53:33.014870, Shed 72-21A Off (RI12)
 179, 3-F35-2, 422, Dec 08 2015 15:53:33.014870, Shed 72-5A Off (RI5)
 180, 3-F35-3, 281, Dec 08 2015 15:53:33.014462, Shed 3-6A Off (RI23)
 181, 3-F35-3, 280, Dec 08 2015 15:53:33.014462, Shed 72-25A Off (RI15)
 182, 3-F35-3, 279, Dec 08 2015 15:53:33.014462, Shed 72-21A Off (RI12)
 183, 3-F35-3, 278, Dec 08 2015 15:53:33.014462, Shed 72-5A Off (RI5)
 184, 3-F35-1, 277, Dec 08 2015 15:53:33.014386, Shed 3-6A Off (RI23)
 185, 3-F35-1, 276, Dec 08 2015 15:53:33.014386, Shed 72-25A Off (RI15)
 186, 3-F35-1, 275, Dec 08 2015 15:53:33.014386, Shed 72-21A Off (RI12)
 187, 3-F35-1, 274, Dec 08 2015 15:53:33.014386, Shed 72-5A Off (RI5)
 188, 72-F35-1, 328, Dec 08 2015 15:53:33.013970, Shed 3-6A Off (RI23)
 189, 72-F35-1, 327, Dec 08 2015 15:53:33.013970, Shed 72-25A Off (RI15)
 190, 72-F35-1, 326, Dec 08 2015 15:53:33.013970, Shed 72-21A Off (RI12)
 191, 72-F35-1, 325, Dec 08 2015 15:53:33.013970, Shed 72-5A Off (RI5)
 192, 72-F35-3, 433, Dec 08 2015 15:53:33.013909, Shed 3-6A Off (RI23)
 193, 72-F35-3, 432, Dec 08 2015 15:53:33.013909, Shed 72-25A Off (RI15)
 194, 72-F35-3, 431, Dec 08 2015 15:53:33.013909, Shed 72-21A Off (RI12)
 195, 72-F35-3, 430, Dec 08 2015 15:53:33.013909, Shed 72-5A Off (RI5)
 196, 72-F35-2, 428, Dec 08 2015 15:53:33.013903, Shed 3-6A Off (RI23)
 197, 72-F35-2, 427, Dec 08 2015 15:53:33.013903, Shed 72-25A Off (RI15)
 198, 72-F35-2, 426, Dec 08 2015 15:53:33.013903, Shed 72-21A Off (RI12)
 199, 72-F35-2, 425, Dec 08 2015 15:53:33.013903, Shed 72-5A Off (RI5)
 200, 72-F35-4, 299, Dec 08 2015 15:53:33.013889, Shed 3-6A Off (RI23)

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201, 72-F35-4, 298, Dec 08 2015 15:53:33.013889, Shed 72-25A Off (RI15)
 202, 72-F35-4, 297, Dec 08 2015 15:53:33.013889, Shed 72-21A Off (RI12)
 203, 72-F35-4, 296, Dec 08 2015 15:53:33.013889, Shed 72-5A Off (RI5)
 204, 72-F35-4, 295, Dec 08 2015 15:52:13.319978, DG1-26A-OPN Off (CI4)
 205, 72-F35-4, 294, Dec 08 2015 15:51:57.945143, DG2-27A-OPN Off (CI5)
 206, 72-F35-2, 424, Dec 08 2015 15:51:33.044937, 72-9A-OPN On (CI3)
 207, 72-F35-3, 429, Dec 08 2015 15:51:33.043392, 72-21A-OPN On (CI5)
 208, 72-F35-3, 428, Dec 08 2015 15:51:33.042385, 72-17A-OPN On (CI3)
 209, 72-F35-4, 293, Dec 08 2015 15:51:33.042360, 72-25A-OPN On (CI3)
 210, 72-F35-3, 427, Dec 08 2015 15:51:33.039385, 72-18-OPN On (CI4)
 211, 72-F35-2, 423, Dec 08 2015 15:51:33.038937, 72-8A-OPN On (CI2)
 212, 3-F35-2, 421, Dec 08 2015 15:51:33.015370, Trip 3-6A On (CO1)
 213, 3-F35-2, 420, Dec 08 2015 15:51:33.015370, FAULT RPT TRIG
 214, 72-F35-4, 292, Dec 08 2015 15:51:33.014193, Trip 25A On (CO5)
 215, 72-F35-4, 291, Dec 08 2015 15:51:33.014193, OSCILLOGRAPHY TRIG'D
 216, 72-F35-4, 290, Dec 08 2015 15:51:33.014193, Osc Trigger On (VO64)
 217, 72-F35-1, 324, Dec 08 2015 15:51:33.014105, Trip 72-5A On (CO9)
 218, 72-F35-1, 323, Dec 08 2015 15:51:33.014105, OSCILLOGRAPHY TRIG'D
 219, 72-F35-1, 322, Dec 08 2015 15:51:33.014105, Osc Trigger On (VO64)
 220, 72-F35-3, 426, Dec 08 2015 15:51:33.013986, Trip 72-21A On (CO9)
 221, 72-F35-3, 425, Dec 08 2015 15:51:33.013986, FAULT RPT TRIG
 222, 3-F35-2, 419, Dec 08 2015 15:51:33.013289, Shed 3-6A On (RI23)
 223, 3-F35-2, 418, Dec 08 2015 15:51:33.013289, Shed 72-25A On (RI15)
 224, 3-F35-2, 417, Dec 08 2015 15:51:33.013289, Shed 72-21A On (RI12)
 225, 3-F35-2, 416, Dec 08 2015 15:51:33.013289, Shed 72-5A On (RI5)
 226, 3-F35-2, 415, Dec 08 2015 15:51:33.013289, Trip 3-13A On (CO6)
 227, 3-F35-2, 414, Dec 08 2015 15:51:33.013289, Trip 3-7A On (CO2)
 228, 3-F35-2, 413, Dec 08 2015 15:51:33.013289, OSCILLOGRAPHY TRIG'D
 229, 3-F35-2, 412, Dec 08 2015 15:51:33.013289, Osc Trigger On (VO64)
 230, 3-F35-2, 411, Dec 08 2015 15:51:33.013289, FAULT RPT TRIG
 231, 3-F35-2, 410, Dec 08 2015 15:51:33.013289, FAULT RPT TRIG
 232, 3-F35-3, 277, Dec 08 2015 15:51:33.012912, Shed 3-6A On (RI23)
 233, 3-F35-3, 276, Dec 08 2015 15:51:33.012912, Shed 72-25A On (RI15)
 234, 3-F35-3, 275, Dec 08 2015 15:51:33.012912, Shed 72-21A On (RI12)
 235, 3-F35-3, 274, Dec 08 2015 15:51:33.012912, Shed 72-5A On (RI5)
 236, F-F35-1, 457, Dec 08 2015 15:51:33.012879, Shed F5-9-10 On (RI28)
 237, F-F35-1, 456, Dec 08 2015 15:51:33.012879, Shed 3-6A On (RI23)
 238, F-F35-1, 455, Dec 08 2015 15:51:33.012879, Shed 72-25A On (RI15)
 239, F-F35-1, 454, Dec 08 2015 15:51:33.012879, Shed 72-21A On (RI12)
 240, F-F35-1, 453, Dec 08 2015 15:51:33.012879, Shed 72-5A On (RI5)
 241, F-F35-1, 452, Dec 08 2015 15:51:33.012879, Trip F-10 On (CO5)
 242, F-F35-1, 451, Dec 08 2015 15:51:33.012879, Trip F-9 On (CO2)
 243, F-F35-1, 450, Dec 08 2015 15:51:33.012879, Trip F-5 On (CO1)
 244, 3-F35-1, 273, Dec 08 2015 15:51:33.012832, Shed 3-6A On (RI23)
 245, 3-F35-1, 272, Dec 08 2015 15:51:33.012832, Shed 72-25A On (RI15)
 246, 3-F35-1, 271, Dec 08 2015 15:51:33.012832, Shed 72-21A On (RI12)
 247, 3-F35-1, 270, Dec 08 2015 15:51:33.012832, Shed 72-5A On (RI5)
 248, 72-F35-4, 289, Dec 08 2015 15:51:33.012107, Shed 3-6A On (RI23)
 249, 72-F35-4, 288, Dec 08 2015 15:51:33.012107, Shed 72-25A On (RI15)
 250, 72-F35-4, 287, Dec 08 2015 15:51:33.012107, Shed 72-21A On (RI12)
 251, 72-F35-4, 286, Dec 08 2015 15:51:33.012107, Shed 72-5A On (RI5)
 252, 72-F35-2, 422, Dec 08 2015 15:51:33.012080, Shed 3-6A On (RI23)
 253, 72-F35-2, 421, Dec 08 2015 15:51:33.012080, Shed 72-25A On (RI15)

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254, 72-F35-2, 420, Dec 08 2015 15:51:33.012080, Shed 72-21A On (RI12)
 255, 72-F35-2, 419, Dec 08 2015 15:51:33.012080, Shed 72-5A On (RI5)
 256, 72-F35-2, 418, Dec 08 2015 15:51:33.012080, Trip 72-9A On (CO5)
 257, 72-F35-2, 417, Dec 08 2015 15:51:33.012080, Trip 72-8A On (CO2)
 258, 72-F35-2, 416, Dec 08 2015 15:51:33.012080, OSCILLOGRAPHY TRIG'D
 259, 72-F35-2, 415, Dec 08 2015 15:51:33.012080, Osc Trigger On (VO64)
 260, 72-F35-2, 414, Dec 08 2015 15:51:33.012080, FAULT RPT TRIG
 261, 72-F35-2, 413, Dec 08 2015 15:51:33.012080, FAULT RPT TRIG
 262, 72-F35-2, 412, Dec 08 2015 15:51:33.012080, FAULT RPT TRIG
 263, 72-F35-1, 321, Dec 08 2015 15:51:33.012019, Shed 3-6A On (RI23)
 264, 72-F35-1, 320, Dec 08 2015 15:51:33.012019, Shed 72-25A On (RI15)
 265, 72-F35-1, 319, Dec 08 2015 15:51:33.012019, Shed 72-21A On (RI12)
 266, 72-F35-1, 318, Dec 08 2015 15:51:33.012019, Shed 72-5A On (RI5)
 267, 72-F35-3, 424, Dec 08 2015 15:51:33.011901, Shed 3-6A On (RI23)
 268, 72-F35-3, 423, Dec 08 2015 15:51:33.011901, Shed 72-25A On (RI15)
 269, 72-F35-3, 422, Dec 08 2015 15:51:33.011901, Shed 72-21A On (RI12)
 270, 72-F35-3, 421, Dec 08 2015 15:51:33.011901, Shed 72-5A On (RI5)
 271, 72-F35-3, 420, Dec 08 2015 15:51:33.011901, Trip 72-18A On (CO6)
 272, 72-F35-3, 419, Dec 08 2015 15:51:33.011901, Trip 72-17A On (CO5)
 273, 72-F35-3, 418, Dec 08 2015 15:51:33.011901, OSCILLOGRAPHY TRIG'D
 274, 72-F35-3, 417, Dec 08 2015 15:51:33.011901, Osc Trigger On (VO64)
 275, 72-F35-3, 416, Dec 08 2015 15:51:33.011901, FAULT RPT TRIG
 276, 72-F35-3, 415, Dec 08 2015 15:51:33.011901, FAULT RPT TRIG
 277, 3-F35-2, 409, Dec 08 2015 15:51:33.011203, SYS ISL3-13A On (RI25)
 278, 3-F35-2, 408, Dec 08 2015 15:51:33.011203, SYS ISL 3-7A On (RI24)
 279, F-F35-1, 449, Dec 08 2015 15:51:33.010798, OSCILLOGRAPHY TRIG'D
 280, F-F35-1, 448, Dec 08 2015 15:51:33.010798, Osc Trigger On (VO64)
 281, 72-F35-2, 411, Dec 08 2015 15:51:33.009994, SYS ISL72-9A On (RI8)
 282, 72-F35-2, 410, Dec 08 2015 15:51:33.009994, SYS ISL72-8A On (RI7)
 283, 72-F35-3, 414, Dec 08 2015 15:51:33.009814, SYS ISL72-18A On (RI11)
 284, 72-F35-3, 413, Dec 08 2015 15:51:33.009814, SYS IS72-17A On (RI10)
 285, 3-F35-2, 407, Dec 08 2015 15:48:00.233151, LS Normal On (RI30)
 286, F-F35-1, 447, Dec 08 2015 15:48:00.232746, LS Normal On (RI30)
 287, 3-F35-3, 273, Dec 08 2015 15:48:00.232680, LS Normal On (RI30)
 288, 3-F35-1, 269, Dec 08 2015 15:48:00.232514, LS Normal On (RI30)
 289, 72-F35-2, 409, Dec 08 2015 15:48:00.232298, LS Normal On (RI30)
 290, 72-F35-1, 317, Dec 08 2015 15:48:00.232214, LS Normal On (RI30)
 291, 72-F35-4, 285, Dec 08 2015 15:48:00.232153, LS Normal On (RI30)
 292, 72-F35-3, 412, Dec 08 2015 15:48:00.231788, LS Normal On (RI30)
 293, 3-F35-2, 406, Dec 08 2015 15:48:00.183146, LS Running On (RI29)
 294, F-F35-1, 446, Dec 08 2015 15:48:00.182743, LS Running On (RI29)
 295, 3-F35-3, 272, Dec 08 2015 15:48:00.182683, LS Running On (RI29)
 296, 3-F35-1, 268, Dec 08 2015 15:48:00.182510, LS Running On (RI29)
 297, 72-F35-2, 408, Dec 08 2015 15:48:00.182295, LS Running On (RI29)
 298, 72-F35-1, 316, Dec 08 2015 15:48:00.182211, LS Running On (RI29)
 299, 72-F35-4, 284, Dec 08 2015 15:48:00.182150, LS Running On (RI29)
 300, 72-F35-3, 411, Dec 08 2015 15:48:00.181784, LS Running On (RI29)
 301, 72-F35-1, 315, Dec 08 2015 14:26:52.833146, 72-3A-OPN On (CI3)
 302, 72-F35-2, 407, Dec 08 2015 14:04:23.972904, GTG2-10A-OPN On (CI4)
 303, F-F35-1, 445, Dec 08 2015 13:01:59.886120, OSCILLOGRAPHY CLEAR
 304, 3-F35-3, 271, Dec 08 2015 09:20:11.092204, DATE/TIME CHANGED
 305, 3-F35-1, 267, Dec 08 2015 09:19:40.687542, DATE/TIME CHANGED
 306, 72-F35-4, 283, Dec 08 2015 09:17:25.884259, DATE/TIME CHANGED

Untitled

307, 3-F35-3, 270, Dec 08 2015 09:16:47.630713, DATE/TIME CHANGED
308, F-F35-1, 444, Dec 08 2015 09:16:38.436685, DATE/TIME CHANGED
309, 72-F35-1, 314, Dec 08 2015 09:16:15.949628, DATE/TIME CHANGED
310, 3-F35-1, 266, Dec 08 2015 09:16:15.486844, DATE/TIME CHANGED
311, 72-F35-3, 409, Dec 08 2015 09:15:25.177813, DATE/TIME CHANGED
312, 72-F35-3, 410, Dec 08 2015 09:15:20.999352, DATE/TIME CHANGED
313, 3-F35-3, 269, Dec 08 2015 09:14:51.323616, DATE/TIME CHANGED
314, 72-F35-2, 406, Dec 08 2015 09:14:20.628781, DATE/TIME CHANGED
315, 3-F35-2, 404, Dec 08 2015 09:14:14.819094, DATE/TIME CHANGED
316, 3-F35-2, 405, Dec 08 2015 09:14:10.944372, DATE/TIME CHANGED
317, 72-F35-4, 282, Dec 08 2015 09:14:00.435920, DATE/TIME CHANGED
318, 3-F35-1, 265, Dec 08 2015 09:13:41.200197, DATE/TIME CHANGED
319, 3-F35-3, 268, Dec 08 2015 09:13:30.077829, DATE/TIME CHANGED
320, F-F35-1, 443, Dec 08 2015 09:13:17.644851, DATE/TIME CHANGED
321, F-F35-1, 442, Dec 08 2015 09:13:02.276611, DATE/TIME CHANGED

Event Recorder - Ameresco-PNS PVT Live\Live Test Event Files\F-F35-1\
EVT_231_2015112 9 6

Event Number	Date/Time	Cause	Data
483	Dec 08 2015 18:26:41.615850	Trip F-10 Off (CO5)	
482	Dec 08 2015 18:26:38.775147	Trip F-9 Off (CO2)	
481	Dec 08 2015 17:54:56.182284	Trip F-5 Off (CO1)	
480	Dec 08 2015 17:54:56.182284	Osc Trigger Off (VO64)	
479	Dec 08 2015 17:50:03.132004	LS Normal Off (RI30)	
478	Dec 08 2015 17:50:03.081995	LS Running Off (RI29)	
477	Dec 08 2015 17:41:57.178658	Trip F-10 On (CO5)	
476	Dec 08 2015 17:41:57.178658	Trip F-9 On (CO2)	
475	Dec 08 2015 17:41:57.178658	Trip F-5 On (CO1)	
474	Dec 08 2015 17:41:57.176574	OSCILLOGRAPHY TRIG'D	
473	Dec 08 2015 17:41:57.176574	Osc Trigger On (VO64)	
472	Dec 08 2015 17:38:45.395640	LS Normal On (RI30)	
471	Dec 08 2015 17:38:45.345631	LS Running On (RI29)	
470	Dec 08 2015 16:28:43.354116	Trip F-10 Off (CO5)	
469	Dec 08 2015 16:28:40.911906	Trip F-9 Off (CO2)	
468	Dec 08 2015 16:28:38.192715	Trip F-5 Off (CO1)	
467	Dec 08 2015 16:28:38.192715	Osc Trigger Off (VO64)	
466	Dec 08 2015 15:56:41.812262	LS Normal Off (RI30)	
465	Dec 08 2015 15:56:41.762255	LS Running Off (RI29)	
464	Dec 08 2015 15:56:39.512110	Reset LED Off (RI31)	
463	Dec 08 2015 15:56:39.362106	Reset LED On (RI31)	
462	Dec 08 2015 15:53:33.016165	Shed F5-9-10 Off (RI28)	
461	Dec 08 2015 15:53:33.016165	Shed 3-6A Off (RI23)	
460	Dec 08 2015 15:53:33.016165	Shed 72-25A Off (RI15)	
459	Dec 08 2015 15:53:33.016165	Shed 72-21A Off (RI12)	
458	Dec 08 2015 15:53:33.016165	Shed 72-5A Off (RI5)	
457	Dec 08 2015 15:51:33.012879	Shed F5-9-10 On (RI28)	
456	Dec 08 2015 15:51:33.012879	Shed 3-6A On (RI23)	
455	Dec 08 2015 15:51:33.012879	Shed 72-25A On (RI15)	
454	Dec 08 2015 15:51:33.012879	Shed 72-21A On (RI12)	
453	Dec 08 2015 15:51:33.012879	Shed 72-5A On (RI5)	
452	Dec 08 2015 15:51:33.012879	Trip F-10 On (CO5)	
451	Dec 08 2015 15:51:33.012879	Trip F-9 On (CO2)	
450	Dec 08 2015 15:51:33.012879	Trip F-5 On (CO1)	
449	Dec 08 2015 15:51:33.010798	OSCILLOGRAPHY TRIG'D	
448	Dec 08 2015 15:51:33.010798	Osc Trigger On (VO64)	
447	Dec 08 2015 15:48:00.232746	LS Normal On (RI30)	
446	Dec 08 2015 15:48:00.182743	LS Running On (RI29)	
445	Dec 08 2015 13:01:59.886120	OSCILLOGRAPHY CLEAR	
444	Dec 08 2015 09:16:38.436685	DATE/TIME CHANGED	
443	Dec 08 2015 09:13:17.644851	DATE/TIME CHANGED	
442	Dec 08 2015 09:13:02.276611	DATE/TIME CHANGED	

Live Event #1: Events 2 - 57
System Reset: Events 58 - 7
Live Event #2: Events 71 - 77
System Reset: Events 78 - 8

Event Recorder - Ameresco-PNS PVT Live\Live Test Event Files\72-F35-1D\
 EVT_211_20151120090600

Event Number	Date/Time	Cause	Data
339	Dec 08 2015 18:25:17.670461	72-3A-OPN Off (CI3)	
338	Dec 08 2015 17:50:03.130326	LS Normal Off (RI30)	
337	Dec 08 2015 17:50:03.080337	LS Running Off (RI29)	
336	Dec 08 2015 17:38:45.394965	LS Normal On (RI30)	
335	Dec 08 2015 17:38:45.344955	LS Running On (RI29)	
334	Dec 08 2015 16:58:05.253582	Trip 72-5A Off (CO9)	
333	Dec 08 2015 16:58:05.253582	Osc Trigger Off (VO64)	
332	Dec 08 2015 15:56:41.811223	LS Normal Off (RI30)	
331	Dec 08 2015 15:56:41.761231	LS Running Off (RI29)	
330	Dec 08 2015 15:56:39.511838	Reset LED Off (RI31)	
329	Dec 08 2015 15:56:39.361871	Reset LED On (RI31)	
328	Dec 08 2015 15:53:33.013970	Shed 3-6A Off (RI23)	
327	Dec 08 2015 15:53:33.013970	Shed 72-25A Off (RI15)	
326	Dec 08 2015 15:53:33.013970	Shed 72-21A Off (RI12)	
325	Dec 08 2015 15:53:33.013970	Shed 72-5A Off (RI5)	
324	Dec 08 2015 15:51:33.014105	Trip 72-5A On (CO9)	
323	Dec 08 2015 15:51:33.014105	OSCILLOGRAPHY TRIG'	
322	Dec 08 2015 15:51:33.014105	Osc Trigger On (VO64)	
321	Dec 08 2015 15:51:33.012019	Shed 3-6A On (RI23)	
320	Dec 08 2015 15:51:33.012019	Shed 72-25A On (RI15)	
319	Dec 08 2015 15:51:33.012019	Shed 72-21A On (RI12)	
318	Dec 08 2015 15:51:33.012019	Shed 72-5A On (RI5)	
317	Dec 08 2015 15:48:00.232214	LS Normal On (RI30)	
316	Dec 08 2015 15:48:00.182211	LS Running On (RI29)	
315	Dec 08 2015 14:26:52.833146	72-3A-OPN On (CI3)	
314	Dec 08 2015 09:16:15.949628	DATE/TIME CHANGED	

Live Event #1: Events 01 - 02
 System Reset: Events 025 - 000
 Live Event #2: Events 005 - 006
 System Reset: Events 007 - 009

Event Recorder - Ameresco-PNS PVT Live\Live Test Event Files\72-F35-2D\
EVT_212_2015112 9 6

Event Number	Date/Time	Cause	Data
466	Dec 08 2015 18:27:19.555631	Trip 72-9A Off (CO5)	
465	Dec 08 2015 18:27:17.046296	Trip 72-8A Off (CO2)	
464	Dec 08 2015 18:27:17.046296	Osc Trigger Off (VO64)	
463	Dec 08 2015 18:09:47.204416	72-9A-OPN Off (CI3)	
462	Dec 08 2015 17:53:56.942239	72-8A-OPN Off (CI2)	
461	Dec 08 2015 17:53:56.928238	72-8A-OPN On (CI2)	
460	Dec 08 2015 17:53:56.878736	72-8A-OPN Off (CI2)	
459	Dec 08 2015 17:50:03.129750	LS Normal Off (RI30)	
458	Dec 08 2015 17:50:03.081849	SYS ISL72-9A Off (RI8)	
457	Dec 08 2015 17:50:03.081849	SYS ISL72-8A Off (RI7)	
456	Dec 08 2015 17:50:03.079765	LS Running Off (RI29)	
455	Dec 08 2015 17:41:57.206725	72-9A-OPN On (CI3)	
454	Dec 08 2015 17:41:57.202742	72-8A-OPN On (CI2)	
453	Dec 08 2015 17:41:57.177589	Trip 72-9A On (CO5)	
452	Dec 08 2015 17:41:57.177589	Trip 72-8A On (CO2)	
451	Dec 08 2015 17:41:57.177589	OSCILLOGRAPHY TRIG'	
450	Dec 08 2015 17:41:57.177589	Osc Trigger On (VO64)	
449	Dec 08 2015 17:41:57.177589	FAULT RPT TRIG	
448	Dec 08 2015 17:41:57.177589	FAULT RPT TRIG	
447	Dec 08 2015 17:41:57.177589	FAULT RPT TRIG	
446	Dec 08 2015 17:41:57.175494	SYS ISL72-9A On (RI8)	
445	Dec 08 2015 17:41:57.175494	SYS ISL72-8A On (RI7)	
444	Dec 08 2015 17:38:45.394436	LS Normal On (RI30)	
443	Dec 08 2015 17:38:45.344429	LS Running On (RI29)	
442	Dec 08 2015 16:58:35.915299	Trip 72-9A Off (CO5)	
441	Dec 08 2015 16:58:33.064602	Trip 72-8A Off (CO2)	
440	Dec 08 2015 16:58:33.064602	Osc Trigger Off (VO64)	
439	Dec 08 2015 16:49:31.066095	GTG2-10A-OPN Off (CI4)	
438	Dec 08 2015 16:24:44.493624	72-9A-OPN Off (CI3)	
437	Dec 08 2015 16:06:55.601190	72-8A-OPN Off (CI2)	
436	Dec 08 2015 16:06:55.586688	72-8A-OPN On (CI2)	
435	Dec 08 2015 16:06:55.537186	72-8A-OPN Off (CI2)	
434	Dec 08 2015 15:56:41.811063	LS Normal Off (RI30)	
433	Dec 08 2015 15:56:41.763160	SYS ISL72-9A Off (RI8)	
432	Dec 08 2015 15:56:41.763160	SYS ISL72-8A Off (RI7)	
431	Dec 08 2015 15:56:41.761076	LS Running Off (RI29)	
430	Dec 08 2015 15:56:39.511686	Reset LED Off (RI31)	
429	Dec 08 2015 15:56:39.361713	Reset LED On (RI31)	
428	Dec 08 2015 15:53:33.013903	Shed 3-6A Off (RI23)	
427	Dec 08 2015 15:53:33.013903	Shed 72-25A Off (RI15)	
426	Dec 08 2015 15:53:33.013903	Shed 72-21A Off (RI12)	
425	Dec 08 2015 15:53:33.013903	Shed 72-5A Off (RI5)	
424	Dec 08 2015 15:51:33.044937	72-9A-OPN On (CI3)	
423	Dec 08 2015 15:51:33.038937	72-8A-OPN On (CI2)	
422	Dec 08 2015 15:51:33.012080	Shed 3-6A On (RI23)	
421	Dec 08 2015 15:51:33.012080	Shed 72-25A On (RI15)	
420	Dec 08 2015 15:51:33.012080	Shed 72-21A On (RI12)	
419	Dec 08 2015 15:51:33.012080	Shed 72-5A On (RI5)	
418	Dec 08 2015 15:51:33.012080	Trip 72-9A On (CO5)	
417	Dec 08 2015 15:51:33.012080	Trip 72-8A On (CO2)	
416	Dec 08 2015 15:51:33.012080	OSCILLOGRAPHY TRIG'	
415	Dec 08 2015 15:51:33.012080	Osc Trigger On (VO64)	
414	Dec 08 2015 15:51:33.012080	FAULT RPT TRIG	

Event Recorder - Ameresco-PNS PVT Live\Live Test Event Files\72-F35-2D\
EVT_212_20151120090600

Event Number	Date/Time	Cause	Data
413	Dec 08 2015 15:51:33.012080	FAULT RPT TRIG	
412	Dec 08 2015 15:51:33.012080	FAULT RPT TRIG	
411	Dec 08 2015 15:51:33.009994	SYS ISL72-9A On (RI8)	
410	Dec 08 2015 15:51:33.009994	SYS ISL72-8A On (RI7)	
409	Dec 08 2015 15:48:00.232298	LS Normal On (RI30)	
408	Dec 08 2015 15:48:00.182295	LS Running On (RI29)	
407	Dec 08 2015 14:04:23.972904	GTG2-10A-OPN On (CI4)	
406	Dec 08 2015 09:14:20.628781	DATE/TIME CHANGED	

Live Test #1: Events 006-020
System Reset: Events 025-002
Live Test # 2: Events 000-055
System Reset: Events 056-066

Event Number	Date/Time	Cause	Data
471	Dec 08 2015 18:27:11.555934	Trip 72-18A Off (CO6)	
470	Dec 08 2015 18:27:09.086089	Trip 72-17A Off (CO5)	
469	Dec 08 2015 18:27:09.086089	Osc Trigger Off (VO64)	
468	Dec 08 2015 18:09:08.311929	72-18-OPN Off (CI4)	
467	Dec 08 2015 18:09:08.299428	72-18-OPN On (CI4)	
466	Dec 08 2015 18:09:08.251941	72-18-OPN Off (CI4)	
465	Dec 08 2015 17:55:27.523287	72-17A-OPN Off (CI3)	
464	Dec 08 2015 17:50:03.129673	LS Normal Off (RI30)	
463	Dec 08 2015 17:50:03.081774	SYSISL72-18A Off (RI11)	
462	Dec 08 2015 17:50:03.081774	SYS IS72-17A Off (RI10)	
461	Dec 08 2015 17:50:03.079689	LS Running Off (RI29)	
460	Dec 08 2015 17:41:57.206011	72-17A-OPN On (CI3)	
459	Dec 08 2015 17:41:57.204011	72-18-OPN On (CI4)	
458	Dec 08 2015 17:41:57.177663	Trip 72-18A On (CO6)	
457	Dec 08 2015 17:41:57.177663	Trip 72-17A On (CO5)	
456	Dec 08 2015 17:41:57.177663	OSCILLOGRAPHY TRIG'	
455	Dec 08 2015 17:41:57.177663	Osc Trigger On (VO64)	
454	Dec 08 2015 17:41:57.177663	FAULT RPT TRIG	
453	Dec 08 2015 17:41:57.177663	FAULT RPT TRIG	
452	Dec 08 2015 17:41:57.175575	SYSISL72-18A On (RI11)	
451	Dec 08 2015 17:41:57.175575	SYS IS72-17A On (RI10)	
450	Dec 08 2015 17:38:45.394393	LS Normal On (RI30)	
449	Dec 08 2015 17:38:45.344386	LS Running On (RI29)	
448	Dec 08 2015 16:58:20.893713	Trip 72-21A Off (CO9)	
447	Dec 08 2015 16:58:17.822595	Trip 72-18A Off (CO6)	
446	Dec 08 2015 16:58:14.603734	Trip 72-17A Off (CO5)	
445	Dec 08 2015 16:58:14.603734	Osc Trigger Off (VO64)	
444	Dec 08 2015 16:32:49.005889	72-21A-OPN Off (CI5)	
443	Dec 08 2015 16:24:19.960419	72-18-OPN Off (CI4)	
442	Dec 08 2015 16:24:19.949419	72-18-OPN On (CI4)	
441	Dec 08 2015 16:24:19.899915	72-18-OPN Off (CI4)	
440	Dec 08 2015 16:07:36.179428	72-17A-OPN Off (CI3)	
439	Dec 08 2015 15:56:41.811181	LS Normal Off (RI30)	
438	Dec 08 2015 15:56:41.763277	SYSISL72-18A Off (RI11)	
437	Dec 08 2015 15:56:41.763277	SYS IS72-17A Off (RI10)	
436	Dec 08 2015 15:56:41.761193	LS Running Off (RI29)	
435	Dec 08 2015 15:56:39.511802	Reset LED Off (RI31)	
434	Dec 08 2015 15:56:39.361833	Reset LED On (RI31)	
433	Dec 08 2015 15:53:33.013909	Shed 3-6A Off (RI23)	
432	Dec 08 2015 15:53:33.013909	Shed 72-25A Off (RI15)	
431	Dec 08 2015 15:53:33.013909	Shed 72-21A Off (RI12)	
430	Dec 08 2015 15:53:33.013909	Shed 72-5A Off (RI5)	
429	Dec 08 2015 15:51:33.043392	72-21A-OPN On (CI5)	
428	Dec 08 2015 15:51:33.042385	72-17A-OPN On (CI3)	
427	Dec 08 2015 15:51:33.039385	72-18-OPN On (CI4)	
426	Dec 08 2015 15:51:33.013986	Trip 72-21A On (CO9)	
425	Dec 08 2015 15:51:33.013986	FAULT RPT TRIG	
424	Dec 08 2015 15:51:33.011901	Shed 3-6A On (RI23)	
423	Dec 08 2015 15:51:33.011901	Shed 72-25A On (RI15)	
422	Dec 08 2015 15:51:33.011901	Shed 72-21A On (RI12)	
421	Dec 08 2015 15:51:33.011901	Shed 72-5A On (RI5)	
420	Dec 08 2015 15:51:33.011901	Trip 72-18A On (CO6)	
419	Dec 08 2015 15:51:33.011901	Trip 72-17A On (CO5)	

Event Recorder - Ameresco-PNS PVT Live\Live Test Event Files 72-005-000
 EVT_213_201511200090600

Event Number	Date/Time	Cause	Data
418	Dec 08 2015 15:51:33.011901	OSCILLOGRAPHY TRIG'	
417	Dec 08 2015 15:51:33.011901	Osc Trigger On (VO64)	
416	Dec 08 2015 15:51:33.011901	FAULT RPT TRIG	
415	Dec 08 2015 15:51:33.011901	FAULT RPT TRIG	
414	Dec 08 2015 15:51:33.009814	SYSISL72-18A On (RI11)	
413	Dec 08 2015 15:51:33.009814	SYS IS72-17A On (RI10)	
412	Dec 08 2015 15:48:00.231788	LS Normal On (RI30)	
411	Dec 08 2015 15:48:00.181784	LS Running On (RI29)	
410	Dec 08 2015 09:15:20.999352	DATE/TIME CHANGED	

Live Test #1: Events 001 - 029
 System Reset: Events 000 - 008
 Live Tests #2: Events 009 - 060
 System Reset: Events 061 - 071

Event Recorder - Ameresco-PNS PVT Live\Live Test Event Files\72-F35-4D\
EVT_214_2015112 9 6

Event Number	Date/Time	Cause	Data
318	Dec 08 2015 18:04:32.586968	DG1-26A-OPN On (CI4)	
317	Dec 08 2015 18:04:32.125445	DG2-27A-OPN On (CI5)	
316	Dec 08 2015 17:50:03.129818	LS Normal Off (RI30)	
315	Dec 08 2015 17:50:03.079832	LS Running Off (RI29)	
314	Dec 08 2015 17:42:27.663894	DG1-26A-OPN Off (CI4)	
313	Dec 08 2015 17:42:18.068431	DG2-27A-OPN Off (CI5)	
312	Dec 08 2015 17:38:45.394631	LS Normal On (RI30)	
311	Dec 08 2015 17:38:45.344622	LS Running On (RI29)	
310	Dec 08 2015 16:58:48.411575	Trip 25A Off (CO5)	
309	Dec 08 2015 16:58:48.411575	Osc Trigger Off (VO64)	
308	Dec 08 2015 16:32:27.576327	72-25A-OPN Off (CI3)	
307	Dec 08 2015 16:32:27.567826	72-25A-OPN On (CI3)	
306	Dec 08 2015 16:32:27.516322	72-25A-OPN Off (CI3)	
305	Dec 08 2015 16:15:47.084329	DG1-26A-OPN On (CI4)	
304	Dec 08 2015 16:15:46.660809	DG2-27A-OPN On (CI5)	
303	Dec 08 2015 15:56:41.811149	LS Normal Off (RI30)	
302	Dec 08 2015 15:56:41.761165	LS Running Off (RI29)	
301	Dec 08 2015 15:56:39.511768	Reset LED Off (RI31)	
300	Dec 08 2015 15:56:39.361800	Reset LED On (RI31)	
299	Dec 08 2015 15:53:33.013889	Shed 3-6A Off (RI23)	
298	Dec 08 2015 15:53:33.013889	Shed 72-25A Off (RI15)	
297	Dec 08 2015 15:53:33.013889	Shed 72-21A Off (RI12)	
296	Dec 08 2015 15:53:33.013889	Shed 72-5A Off (RI5)	
295	Dec 08 2015 15:52:13.319978	DG1-26A-OPN Off (CI4)	
294	Dec 08 2015 15:51:57.945143	DG2-27A-OPN Off (CI5)	
293	Dec 08 2015 15:51:33.042360	72-25A-OPN On (CI3)	
292	Dec 08 2015 15:51:33.014193	Trip 25A On (CO5)	
291	Dec 08 2015 15:51:33.014193	OSCILLOGRAPHY TRIG'	
290	Dec 08 2015 15:51:33.014193	Osc Trigger On (VO64)	
289	Dec 08 2015 15:51:33.012107	Shed 3-6A On (RI23)	
288	Dec 08 2015 15:51:33.012107	Shed 72-25A On (RI15)	
287	Dec 08 2015 15:51:33.012107	Shed 72-21A On (RI12)	
286	Dec 08 2015 15:51:33.012107	Shed 72-5A On (RI5)	
285	Dec 08 2015 15:48:00.232153	LS Normal On (RI30)	
284	Dec 08 2015 15:48:00.182150	LS Running On (RI29)	
283	Dec 08 2015 09:17:25.884259	DATE/TIME CHANGED	

Live Test #1: Events 283 - 295
System Reset: Events 296 - 318
Live Tests # 2: Events 311 - 318
System Reset: Events 315 - 318

Event Recorder - Ameresco-PNS PVT Live\Live Test Event Files\3-F35-1\
EVT_231_201511296

Event Number	Date/Time	Cause	Data
285	Dec 08 2015 17:50:03.130397	LS Normal Off (RI30)	
284	Dec 08 2015 17:50:03.080411	LS Running Off (RI29)	
283	Dec 08 2015 17:38:45.395260	LS Normal On (RI30)	
282	Dec 08 2015 17:38:45.345252	LS Running On (RI29)	
281	Dec 08 2015 15:56:41.811659	LS Normal Off (RI30)	
280	Dec 08 2015 15:56:41.761676	LS Running Off (RI29)	
279	Dec 08 2015 15:56:39.512270	Reset LED Off (RI31)	
278	Dec 08 2015 15:56:39.362301	Reset LED On (RI31)	
277	Dec 08 2015 15:53:33.014386	Shed 3-6A Off (RI23)	
276	Dec 08 2015 15:53:33.014386	Shed 72-25A Off (RI15)	
275	Dec 08 2015 15:53:33.014386	Shed 72-21A Off (RI12)	
274	Dec 08 2015 15:53:33.014386	Shed 72-5A Off (RI5)	
273	Dec 08 2015 15:51:33.012832	Shed 3-6A On (RI23)	
272	Dec 08 2015 15:51:33.012832	Shed 72-25A On (RI15)	
271	Dec 08 2015 15:51:33.012832	Shed 72-21A On (RI12)	
270	Dec 08 2015 15:51:33.012832	Shed 72-5A On (RI5)	
269	Dec 08 2015 15:48:00.232514	LS Normal On (RI30)	
268	Dec 08 2015 15:48:00.182510	LS Running On (RI29)	
267	Dec 08 2015 09:19:40.687542	DATE/TIME CHANGED	
266	Dec 08 2015 09:16:15.486844	DATE/TIME CHANGED	
265	Dec 08 2015 09:13:41.200197	DATE/TIME CHANGED	

Live Test #1: Events 265 - 27
System Reset: Events 27 - 281
Live Test #2: Events 282 - 28
System Reset: Events 28 - 285

Event Recorder - Ameresco-PNS PVT Live\Live Test Event Files\3-F35-2D\
EVT_232_2015112 9 6

Event Number	Date/Time	Cause	Data
452	Dec 08 2015 18:26:58.025569	Trip 3-13A Off (CO6)	
451	Dec 08 2015 18:26:55.745121	Trip 3-7A Off (CO2)	
450	Dec 08 2015 18:26:55.745121	Osc Trigger Off (VO64)	
449	Dec 08 2015 17:50:03.130889	LS Normal Off (RI30)	
448	Dec 08 2015 17:50:03.082991	SYS ISL3-13A Off (RI25)	
447	Dec 08 2015 17:50:03.082991	SYS ISL 3-7A Off (RI24)	
446	Dec 08 2015 17:50:03.080903	LS Running Off (RI29)	
445	Dec 08 2015 17:41:57.178821	Trip 3-13A On (CO6)	
444	Dec 08 2015 17:41:57.178821	Trip 3-7A On (CO2)	
443	Dec 08 2015 17:41:57.178821	OSCILLOGRAPHY TRIG'	
442	Dec 08 2015 17:41:57.178821	Osc Trigger On (VO64)	
441	Dec 08 2015 17:41:57.178821	FAULT RPT TRIG	
440	Dec 08 2015 17:41:57.178821	FAULT RPT TRIG	
439	Dec 08 2015 17:41:57.176736	SYS ISL3-13A On (RI25)	
438	Dec 08 2015 17:41:57.176736	SYS ISL 3-7A On (RI24)	
437	Dec 08 2015 17:38:45.395756	LS Normal On (RI30)	
436	Dec 08 2015 17:38:45.345746	LS Running On (RI29)	
435	Dec 08 2015 16:57:41.800748	Trip 3-13A Off (CO6)	
434	Dec 08 2015 16:57:37.881479	Trip 3-7A Off (CO2)	
433	Dec 08 2015 16:57:33.941189	Trip 3-6A Off (CO1)	
432	Dec 08 2015 16:57:33.941189	Osc Trigger Off (VO64)	
431	Dec 08 2015 15:56:41.812039	LS Normal Off (RI30)	
430	Dec 08 2015 15:56:41.764138	SYS ISL3-13A Off (RI25)	
429	Dec 08 2015 15:56:41.764138	SYS ISL 3-7A Off (RI24)	
428	Dec 08 2015 15:56:41.762053	LS Running Off (RI29)	
427	Dec 08 2015 15:56:39.512644	Reset LED Off (RI31)	
426	Dec 08 2015 15:56:39.362677	Reset LED On (RI31)	
425	Dec 08 2015 15:53:33.014870	Shed 3-6A Off (RI23)	
424	Dec 08 2015 15:53:33.014870	Shed 72-25A Off (RI15)	
423	Dec 08 2015 15:53:33.014870	Shed 72-21A Off (RI12)	
422	Dec 08 2015 15:53:33.014870	Shed 72-5A Off (RI5)	
421	Dec 08 2015 15:51:33.015370	Trip 3-6A On (CO1)	
420	Dec 08 2015 15:51:33.015370	FAULT RPT TRIG	
419	Dec 08 2015 15:51:33.013289	Shed 3-6A On (RI23)	
418	Dec 08 2015 15:51:33.013289	Shed 72-25A On (RI15)	
417	Dec 08 2015 15:51:33.013289	Shed 72-21A On (RI12)	
416	Dec 08 2015 15:51:33.013289	Shed 72-5A On (RI5)	
415	Dec 08 2015 15:51:33.013289	Trip 3-13A On (CO6)	
414	Dec 08 2015 15:51:33.013289	Trip 3-7A On (CO2)	
413	Dec 08 2015 15:51:33.013289	OSCILLOGRAPHY TRIG'	
412	Dec 08 2015 15:51:33.013289	Osc Trigger On (VO64)	
411	Dec 08 2015 15:51:33.013289	FAULT RPT TRIG	
410	Dec 08 2015 15:51:33.013289	FAULT RPT TRIG	
409	Dec 08 2015 15:51:33.011203	SYS ISL3-13A On (RI25)	
408	Dec 08 2015 15:51:33.011203	SYS ISL 3-7A On (RI24)	
407	Dec 08 2015 15:48:00.233151	LS Normal On (RI30)	
406	Dec 08 2015 15:48:00.183146	LS Running On (RI29)	
405	Dec 08 2015 09:14:10.944372	DATE/TIME CHANGED	
404	Dec 08 2015 09:14:14.819094	DATE/TIME CHANGED	

Live Test #1: Events 9 - 21
System Reset: Events 22 - 5
Live Test #2: Events 6 - 5
System Reset: Events 6 - 52

Event Recorder - Ameresco-PNS PVT Live\Live Test Event Files\3-F35-3\
EVT_233_2015112 9 6

Event Number	Date/Time	Cause	Data
289	Dec 08 2015 17:50:03.131274	LS Normal Off (RI30)	
288	Dec 08 2015 17:50:03.081282	LS Running Off (RI29)	
287	Dec 08 2015 17:38:45.395556	LS Normal On (RI30)	
286	Dec 08 2015 17:38:45.345548	LS Running On (RI29)	
285	Dec 08 2015 15:56:41.812212	LS Normal Off (RI30)	
284	Dec 08 2015 15:56:41.762225	LS Running Off (RI29)	
283	Dec 08 2015 15:56:39.512822	Reset LED Off (RI31)	
282	Dec 08 2015 15:56:39.362851	Reset LED On (RI31)	
281	Dec 08 2015 15:53:33.014462	Shed 3-6A Off (RI23)	
280	Dec 08 2015 15:53:33.014462	Shed 72-25A Off (RI15)	
279	Dec 08 2015 15:53:33.014462	Shed 72-21A Off (RI12)	
278	Dec 08 2015 15:53:33.014462	Shed 72-5A Off (RI5)	
277	Dec 08 2015 15:51:33.012912	Shed 3-6A On (RI23)	
276	Dec 08 2015 15:51:33.012912	Shed 72-25A On (RI15)	
275	Dec 08 2015 15:51:33.012912	Shed 72-21A On (RI12)	
274	Dec 08 2015 15:51:33.012912	Shed 72-5A On (RI5)	
273	Dec 08 2015 15:48:00.232680	LS Normal On (RI30)	
272	Dec 08 2015 15:48:00.182683	LS Running On (RI29)	
271	Dec 08 2015 09:20:11.092204	DATE/TIME CHANGED	

Live Test #1: Events 271 - 277
System Reset: Events 278 - 285
Live Test #2: Events 286 - 287
System Reset: Events 288 - 289

APPENDIX E - FAST LOAD SHED SYSTEM DRAWINGS

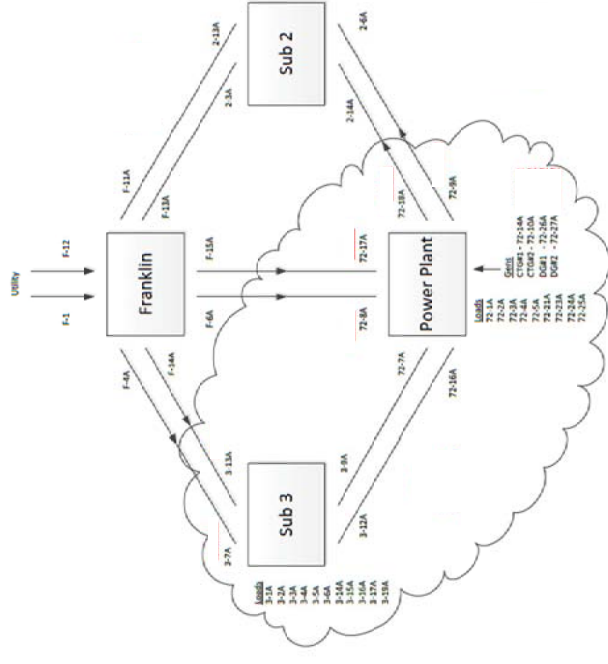
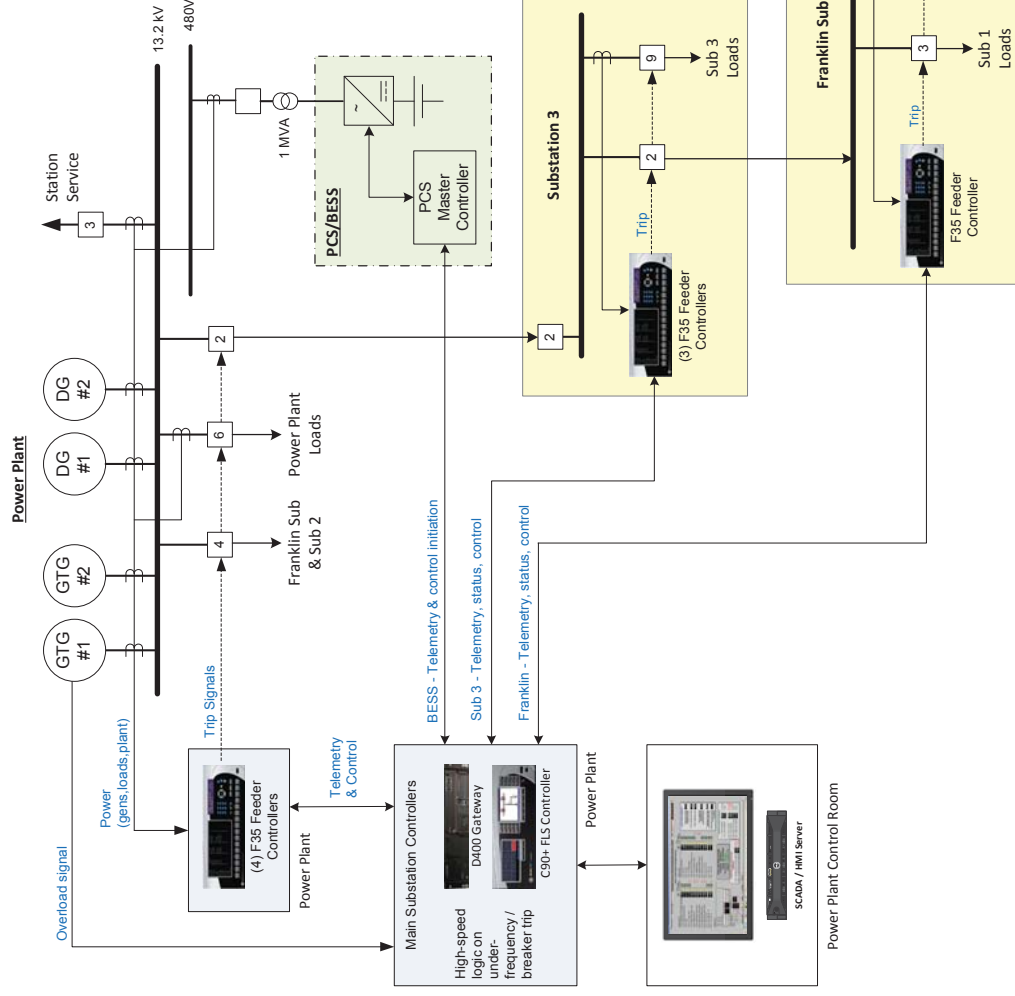
PNS FLS System Overview – Data & Control

PNS FLS System Overview – Communication Architecture Sh.1

PNS FLS System Overview – Communication Architecture Sh.2

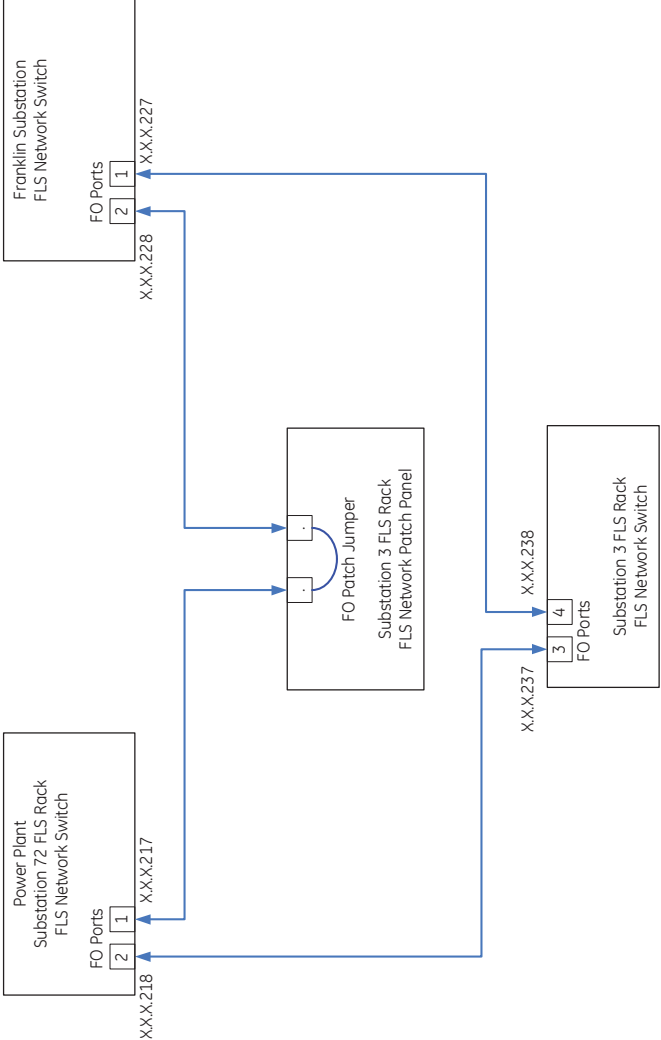
Portsmouth Naval Shipyard Fast Load Shed System Data and Control Scheme

20-Apr-2016

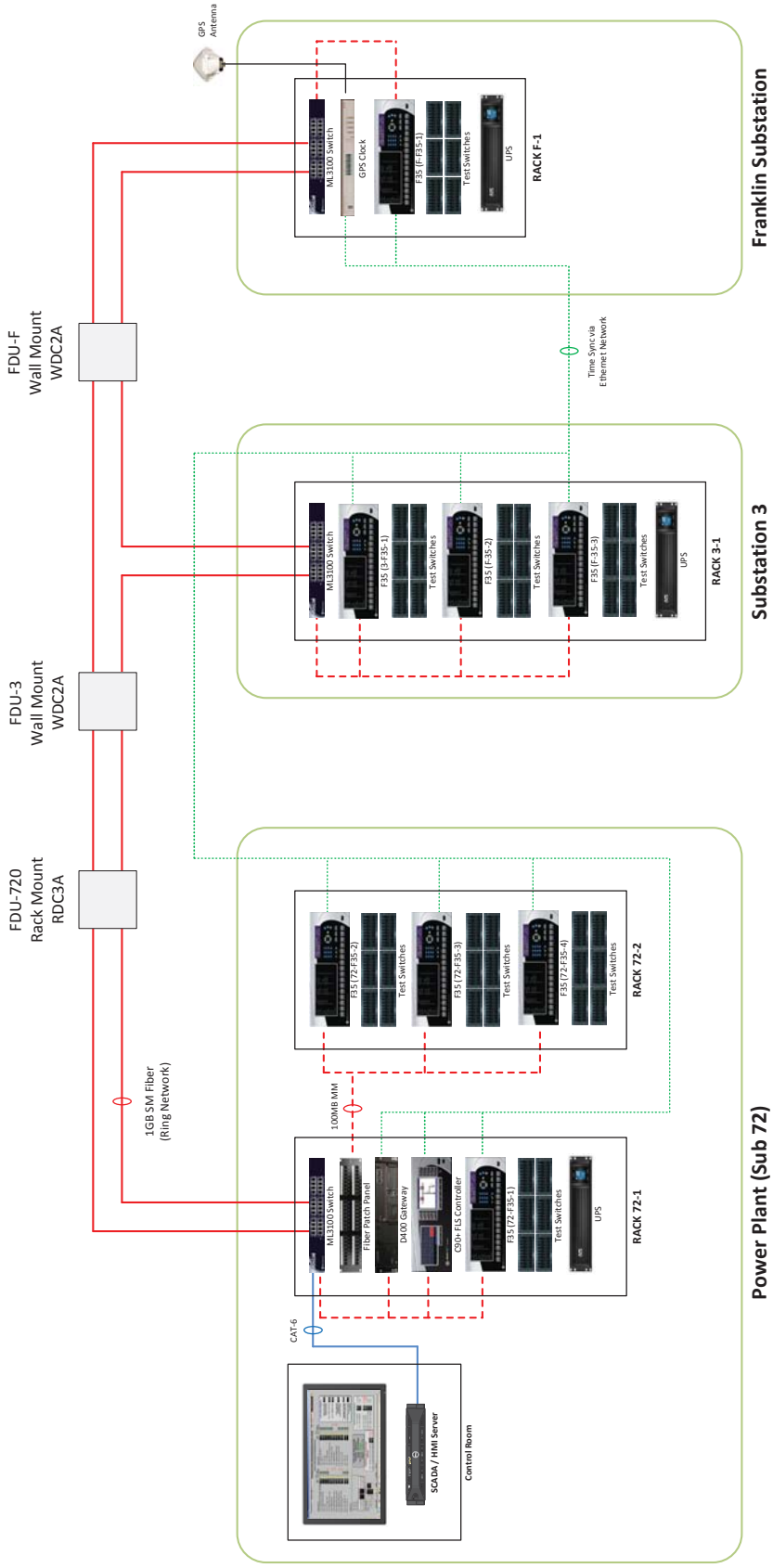


Portsmouth Naval Shipyard
Fast Load Shed System
Communication Network Architecture – Sheet 1

FLS Ethernet Ring Network



Portsmouth Naval Shipyard
Fast Load Shed System
Communication Network Architecture – Sheet 2



1GB SM Fiber

100MB MM Fiber

CAT-6 Ethernet

Time Sync via Ethernet

APPENDIX F – CMP INTERCONNECTION AGREEMENT AND ISO-NE REG MARKET CHECKLIST

Level 3 Interconnection Agreement

This Agreement is made and entered into this 4th day of August 2014 by and between Naval Facilities Engineering Command Mid-Atlantic on behalf of Commander Navy Region, Mid-Atlantic ("Interconnection Customer") located at Navy Yard Line, Kittery, Maine, and Central Maine Power Company, a Maine corporation having its office and principal place of business in Augusta, Kennebec County, Maine, existing under the laws of the State of Maine, ("T&D Utility"). Interconnection Customer and T & D Utility each may be referred to as a "Party," or collectively as the "Parties."

Recitals:

Whereas, Interconnection Customer is proposing to develop a Small Generator Facility, consisting of an 500 kW Battery Energy Storage System, consistent with the Interconnection Requests completed by Interconnection Customer on November 22, 2013; and

Whereas, Interconnection Customer desires to interconnect the Small Generator Facility with T & D Utility's Electric Distribution System.

Now, therefore, in consideration of and subject to the mutual covenants contained herein, the Parties agree as follows:

Article 1. Scope and Limitations of Agreement

- 1.1 This Agreement shall be used for all approved Level 2, Level 3, and Level 4 Interconnection Requests according to the procedures set forth in the Standard Small Generator Interconnection Rule.
- 1.2 This Agreement governs the terms and conditions under which the Small Generator Facility will interconnect to, and operate in Parallel with, T & D Utility's Electric Distribution System.
- 1.3 This Agreement does not constitute an agreement to purchase or deliver the Interconnection Customer's power.
- 1.4 Nothing in this Agreement is intended to affect any other agreement between T & D Utility and the Interconnection Customer. However, in the event that the provisions of this agreement are in conflict with the provisions of the T & D Utility tariff, the T & D Utility tariff shall control.
- 1.5 Responsibilities of the Parties
 - 1.5.1 The Parties shall perform all obligations of this Agreement in accordance with all Applicable Laws and Regulations, and Operating Requirements.
 - 1.5.2 The Interconnection Customer shall construct, interconnect, operate and maintain its Small Generator Facility, and construct, operate, and maintain its Interconnection Equipment in accordance with the applicable manufacturer's recommended maintenance schedule, in accordance with this Agreement.
 - 1.5.3 T & D Utility shall construct, own, operate, and maintain its Electric Distribution System and Interconnection Facilities in accordance with this Agreement.

- 1.5.4 The Interconnection Customer agrees to construct its facilities or systems in accordance with applicable specifications that meet or exceed the National Electrical Code, the American National Standards Institute, IEEE, Underwriters Laboratories, and any other Operating Requirements.
- 1.5.5 Each Party shall operate, maintain, repair, and inspect, and shall be fully responsible for the facilities that it now or subsequently may own unless otherwise specified in the Exhibits to this Agreement and shall do so in a manner as to reasonably minimize the likelihood of a disturbance adversely affecting or impairing the other party
- 1.5.6 Each Party shall be responsible for the safe installation, maintenance, repair and condition of their respective lines and appurtenances on their respective sides of the Point of Common Coupling.
- 1.6 Parallel Operation Obligations Once the Small Generator Facility has been authorized to commence parallel operation, the Interconnection Customer shall abide by all written rules and procedures developed by the T & D Utility which pertain to the parallel operation of the Small Generator Facility, copies of which are provided as an Exhibit to this Agreement.
- 1.7 Reactive Power
The Interconnection Customer shall design its Small Generator Facility to maintain a composite power delivery at continuous rated power output at the Point of Common Coupling at a power factor within the range of 0.95 leading to 0.95 lagging.

Article 2. Inspection, Testing, Authorization, and Right of Access

- 2.1 Equipment Testing and Inspection
The Interconnection Customer shall test and inspect its Small Generator Facility and Interconnection Facilities prior to interconnection, and in accordance with IEEE 1547 Standards.
- 2.2 Certificate of Completion
Prior to commencing parallel operation, the Interconnection Customer shall provide T & D Utility with a Certificate of Completion in the form of Attachment 6 of the Interconnection Forms and Agreements. The Certificate of Completion must either be signed by an electrical inspector with the authority to approve the interconnection or be accompanied by the electrical inspector's own form authorizing interconnection of the Small Generation Facility.
- 2.3 Parallel Operation Obligations
The Interconnection Customer shall abide by all permissible written rules and procedures developed by the T & D Utility which pertain to the parallel operation of the Small Generation Facility. In the event of conflicting provisions the Interconnection Procedures shall take precedence over the T & D Utility's rule or procedure. Copies of the Utilities rules and procedures for parallel operation are either provided as an Exhibit to this Agreement or an Exhibit that provides a reference to a website where copies of the rule or procedure is maintained.

2.4 Right of Access

At reasonable hours, and upon reasonable notice, or at any time without notice in the event of an emergency or hazardous condition, Company shall have access to Customer's premises for any reasonable purpose in connection with the performance of the obligations imposed on it by this Agreement or if necessary to meet its legal obligation to provide service to its Customers.

Article 3. Effective Date, Term, Termination, and Disconnection

3.1 Effective Date

This Agreement shall become effective upon execution by the Parties.

3.2 Term of Agreement

This Agreement shall become effective on the Effective Date and shall remain in effect perpetually, unless terminated earlier in accordance with Article 3.3 of this Agreement.

3.3 Termination

No termination shall become effective until the Parties have complied with all Applicable Laws and Regulations applicable to such termination.

3.3.1 The Interconnection Customer may terminate this Agreement at any time by giving T & D Utility 20 Business Days written notice.

3.3.2 Either Party may terminate this Agreement after Default pursuant to Article 6.6.

3.3.3 Upon termination of this Agreement, the Small Generator Facility will be disconnected from T & D Utility's Electric Distribution System. The termination of this Agreement shall not relieve either Party of its liabilities and obligations, owed or continuing at the time of the termination.

3.3.4 The provisions of this Article shall survive termination or expiration of this Agreement.

3.4 Temporary Disconnection

The T & D Utility may temporarily disconnect the Small Generator Facility from its Electric Distribution System for so long as reasonably necessary in the event one or more of the following conditions or events occurs:

3.4.1 Emergency Conditions

"Emergency Condition" shall mean a condition or situation: (1) that in the judgment of the Party making the claim is imminently likely to endanger life or property; or (2) that, in the case of T & D Utility, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to the Electric Distribution System, T & D Utility's Interconnection Facilities or (3) that, in the case of the Interconnection Customer, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Small Generator Facility or the Interconnection Equipment. Under Emergency Conditions, T & D Utility or the Interconnection Customer may immediately suspend interconnection service and temporarily disconnect the Small Generator Facility. T & D Utility shall notify the Interconnection Customer promptly when it becomes aware of an Emergency Condition that may reasonably be expected to affect the Interconnection Customer's operation of the Small Generator Facility. The

Interconnection Customer shall notify T & D Utility promptly when it becomes aware of an Emergency Condition that may reasonably be expected to affect T & D Utility's Electric Distribution System. To the extent information is known, the notification shall describe the Emergency Condition, the extent of the damage or deficiency, the expected effect on the operation of both Parties' facilities and operations, its anticipated duration, and the necessary corrective action.

3.4.2 Routine Maintenance, Construction, and Repair

T & D Utility may interrupt interconnection service or curtail the output of the Small Generator Facility and temporarily disconnect the Small Generator Facility from T & D Utility's Electric Distribution System when necessary for routine maintenance, construction, and repairs on T & D Utility's Electric Distribution System. T & D Utility shall provide the Interconnection Customer with five Business Days notice prior to such interruption. T & D Utility shall use reasonable efforts to coordinate such reduction or temporary disconnection with the Interconnection Customer.

3.4.3 Forced Outages

During any forced outage, T & D Utility may suspend interconnection service to effect immediate repairs on T & D Utility's Electric Distribution System. T & D Utility shall use reasonable efforts to provide the Interconnection Customer with prior notice. If prior notice is not given, T & D Utility shall, upon request, provide the Interconnection Customer written documentation after the fact explaining the circumstances of the disconnection.

3.4.4 Adverse Operating Effects

T & D Utility shall provide the Interconnection Customer with a written notice of its intention to disconnect the Small Generator Facility if, based on Good Utility Practice, the T & D Utility determines that operation of the Small Generator Facility will likely cause disruption or deterioration of service to other Customers served from the same electric system, or if operating the Small Generator Facility could cause damage to T & D Utility's Electric Distribution System. Supporting documentation used to reach the decision to disconnect shall be provided to the Interconnection Customer upon request. T & D Utility may disconnect the Small Generator Facility if, after receipt of the notice, the Interconnection Customer fails to remedy the adverse operating effect within a reasonable time which shall be at least five Business Days from the date the Interconnection Customer receives the T & D Utility's written notice supporting the decision to disconnect, unless Emergency Conditions exist in which case the provisions of Article 3.4.1 apply.

3.4.5 Modification of the Small Generator Facility

The Interconnection Customer must receive written authorization from T & D Utility before making any change to the Small Generator Facility that may have a material impact on the safety or reliability of the Electric Distribution System. Such authorization shall not be unreasonably withheld. Modifications shall be done in accordance with Good Utility Practice. If the Interconnection Customer makes such modification without T & D Utility's prior written authorization, the latter shall have the right to temporarily disconnect the Small Generator Facility.

3.4.6 Reconnection

The Parties shall cooperate with each other to restore the Small Generator Facility, Interconnection Facilities, and T & D Utility's Electric Distribution System to their normal operating state as soon as reasonably practicable following a temporary disconnection.

Article 4. Cost Responsibility for Interconnection Facilities and Distribution Upgrades

4.1 Interconnection Facilities

- 4.1.1 The Interconnection Customer shall pay for the cost of the Interconnection Facilities itemized in **Exhibit A** to this Agreement. If a Facilities Study was performed, T & D Utility shall identify its Interconnection Facilities necessary to safely interconnect the Small Generator Facility with T & D Utility's Electric Distribution System, the cost of those facilities, and the time required to build and install those facilities.
- 4.1.2 The Interconnection Customer shall be responsible for its share of all reasonable expenses, including overheads, associated with (1) owning, operating, maintaining, repairing, and replacing its Interconnection Equipment, and (2) operating, maintaining, repairing, and replacing T & D Utility's Interconnection Facilities as set forth in **Exhibit A** to this Agreement.

4.2 Distribution Upgrades

T & D Utility shall design, procure, construct, install, and own any Distribution Upgrades. The actual cost of the Distribution Upgrades, including overheads, shall be directly assigned to the Interconnection Customer.

Article 5. Billing, Payment, Milestones, and Financial Security

5.1 Billing and Payment Procedures and Final Accounting

- 5.1.1 T & D Utility shall bill the Interconnection Customer for the design, engineering, construction, and procurement costs of T & D Utility provided Interconnection Facilities and Distribution Upgrades contemplated by this Agreement as set forth in **Exhibit A** to this Agreement, on a monthly basis, or as otherwise agreed by the Parties. The Interconnection Customer shall pay each bill within thirty (30) calendar days of receipt, or as otherwise agreed to by the Parties.
- 5.1.2 Within ninety (90) calendar days of completing the construction and installation of T & D Utility's Interconnection Facilities and Distribution Upgrades described in **Exhibit A** to this Agreement, T & D Utility shall provide the Interconnection Customer with a final accounting report of any difference between (1) the actual cost incurred to complete the construction and installation and the budget estimate provided to the Interconnection Customer and a written explanation for any significant variation. (2) the Interconnection Customer's previous deposit and aggregate payments to T & D Utility for such Interconnection Facilities and Distribution Upgrades. If the Interconnection Customer's cost responsibility exceeds its previous deposit and aggregate payments, T & D Utility shall invoice the Interconnection Customer for the amount due and the Interconnection Customer shall make payment to T & D Utility within thirty (30) calendar days. If the Interconnection Customer's previous deposit and aggregate payments exceed its cost responsibility under this Agreement, T & D Utility shall refund to the Interconnection Customer an amount equal to the

difference within thirty (30) calendar days of the final accounting report.

5.2 Interconnection Customer Deposit

At least twenty (20) Business Days prior to the commencement of the design, procurement, installation, or construction of a discrete portion of T & D Utility's Interconnection Facilities and Distribution Upgrades, the Interconnection Customer shall provide T & D Utility with a deposit equal to 50 percent of the cost estimated for its Interconnection Facilities prior to its beginning design of such facilities.

Article 6. Assignment, Liability, Indemnity, Force Majeure, Consequential Damages, and Default

6.1 Assignment

This Agreement may be assigned by either Party upon fifteen (15) Business Days prior written notice, and with the opportunity to object by the other Party. When required, consent to assignment shall not be unreasonably withheld; provided that:

- 6.1.1 Either Party may assign this Agreement without the consent of the other Party to any affiliate of the assigning Party with an equal or greater credit rating and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this Agreement;
- 6.1.2 The Interconnection Customer shall have the right to assign this Agreement, without the consent of T & D Utility, for collateral security purposes to aid in providing financing for the Small Generator Facility;
- 6.1.3 Any attempted assignment that violates this Article is void and ineffective. Assignment shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof. An assignee is responsible for meeting the same obligations as the Interconnection Customer.

6.2 Limitation of Liability and Indemnification

- 6.2.1 Notwithstanding any other Paragraph of this Agreement, T&D Utility shall assume all liability for and shall indemnify Interconnection Customer for any claims, losses, costs, and expenses of any kind or character to the extent that they result from T&D Utility's negligence in connection with the design, construction, or operation of its facilities as described on **Exhibit A**; provided, however, that T&D Utility shall have no obligation to indemnify Interconnection Customer for claims brought by claimants who cannot recover directly from T&D Utility. Such indemnity shall include, but is not limited to, financial responsibility for: (a) Interconnection Customer's monetary losses; (b) reasonable costs and expenses of defending an action or claim made by a third person; (c) damages related to the death or injury of a third person; (d) damages to the property of Interconnection Customer; (e) damages to the property of a third person. In no event shall T&D Utility be liable for consequential, special, incidental or punitive damages, including, without limitation, loss of profits, loss of revenue, or loss of production. T&D Utility does not assume liability for any costs for damages arising from the disruption of the business of Interconnection Customer or for Interconnection Customer's costs and expenses of prosecuting or defending an action or claim against T&D Utility. This paragraph does not create a liability on the part of T&D Utility to Interconnection Customer or a third person, but requires indemnification where such liability exists. The

limitations of liability provided in this paragraph do not apply in cases of gross negligence or intentional wrongdoing.

- 6.2.2 Notwithstanding any other provision of this Agreement, the liability, if any, of the Government relating to this Agreement, for injury or loss of property, or personal injury or death shall be governed exclusively by the provisions of the Federal Tort Claims Act (28 U.S.C. §§ 1346, and 2671-2680). Subject to applicable Federal, State and local law, each Party's liability to the other for any loss, cost, claim, injury, liability, or expense, including reasonable attorney's fees, relating to or arising from any act or omission in its performance of this agreement shall be limited to the amount of direct damages actually incurred, and in no event shall either Party be liable to the other for any indirect, special, consequential, or punitive damages.
- 6.2.3 T&D Utility and Interconnection Customer shall each be responsible for the safe installation, maintenance, repair and condition of their respective lines and appurtenances on their respective sides of the point of delivery. T&D Utility does not assume any duty of inspecting Interconnection Customer's lines, wires, switches, or other equipment and will not be responsible therefor. Interconnection Customer assumes all responsibility for the electric service supplied hereunder and the facilities used in connection therewith at or beyond the point of delivery, the point of delivery being the point where the electric energy first leaves the wire or facilities provided and owned by T&D Utility and enters the wire or facilities provided by Interconnection Customer.

6.3 RESERVED

6.4 Consequential Damages

Neither Party shall be liable under any provision of this Agreement for any losses, damages, costs or expenses for any special, indirect, incidental, consequential, or punitive damages, including but not limited to loss of profit or revenue, loss of the use of equipment, cost of capital, cost of temporary equipment or services, whether based in whole or in part in contract, in tort, including negligence, strict liability, or any other theory of liability; provided, however, that damages for which a Party may be liable to the other Party under another agreement will not be considered to be special, indirect, incidental, or consequential damages hereunder.

6.5 Force Majeure

- 6.5.1 As used in this Article, a Force Majeure Event shall mean "any act of God, labor disturbance, act of the public enemy, war, acts of terrorism, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure Event does not include an act of negligence or intentional wrongdoing."
- 6.5.2 If a Force Majeure Event prevents a Party from fulfilling any obligations under this Agreement, the Party affected by the Force Majeure Event (Affected Party) shall promptly notify the other Party of the existence of the Force Majeure Event. The notification must specify in reasonable detail the circumstances of the Force Majeure Event, its expected duration, and the steps that the Affected Party is taking to mitigate the effects of the event on its performance, and if the initial notification was verbal, it should be

promptly followed up with a written notification. The Affected Party shall keep the other Party informed on a continuing basis of developments relating to the Force Majeure Event until the event ends. The Affected Party will be entitled to suspend or modify its performance of obligations under this Agreement (other than the obligation to make payments) only to the extent that the effect of the Force Majeure Event cannot be reasonably mitigated. The Affected Party will use reasonable efforts to resume its performance as soon as possible.

6.6 Default

- 6.6.1 No Default shall exist where such failure to discharge an obligation (other than the payment of money) is the result of a Force Majeure Event as defined in this Agreement, or the result of an act or omission of the other Party. Upon a Default, the non-defaulting Party shall give written notice of such Default to the defaulting Party. Except as provided in Article 6.6.2, the defaulting Party shall have 60 calendar days from receipt of the Default notice within which to cure such Default; provided however, if such Default is not capable of cure within 60 calendar days, the defaulting Party shall commence such cure within 20 calendar days after notice and continuously and diligently complete such cure within six months from receipt of the Default notice; and, if cured within such time, the Default specified in such notice shall cease to exist.
- 6.6.2 If a Default is not cured as provided for in this Article, or if a Default is not capable of being cured within the period provided for herein, the non-defaulting Party shall have the right to terminate this Agreement by written notice at any time until cure occurs, and be relieved of any further obligation hereunder and, whether or not that Party terminates this Agreement, to recover from the defaulting Party all amounts due hereunder, plus all other damages and remedies to which it is entitled at law or in equity. The provisions of this Article will survive termination of this Agreement.

Article 7. Insurance

In connection with Interconnection Customer's performance of its duties and obligations under this Agreement, Interconnection Customer agrees that during the term of the Agreement it shall self-insure, subject to and in accordance with the Federal Tort Claims Act, 28 U.S.C. 1346(b) and 2671-2680, the Antideficiency Act, 31 U.S.C. 1341, 1342, 1349, 1350 and 1351, and the Automatic Payment of Judgments Act, 31 U.S.C. 1304 (collectively "Federal Statutes") to cover (with a combined single limit of not more than two million dollars (\$2,000,000) for each occurrence) against claims resulting from bodily injury, wrongful death, and property damage arising out of Interconnection Customer's ownership and/or operations of the Small Generator Facility under this Agreement. Subject to and in accordance with the Federal Statutes, Customer's self-insurance shall include T&D Utility as an additional insured and shall be primary and not excess to or contributing with any insurance or self-insurance maintained by T&D Utility. Notice of all cancellations, terminations, alterations, and material changes of such self-insurance shall be submitted to T&D Utility.

Article 8. Dispute Resolution (see provisions in the Maine Public Utilities Commission's Standard Small Generator Interconnection Rules)

Article 9. Miscellaneous

9.1 Governing Law and Regulatory Authority

This Agreement shall be governed by the laws of the United States of America and, to the extent that there is no applicable or controlling federal law, the laws of the State of Maine, without regard to conflicts of law principles, with the exception that the procedural laws and evidentiary rules of the State of Maine relating to governmental immunities and the authority of T&D Utility to execute and perform its obligations under this Agreement shall apply.

9.2 Amendment

The Parties may amend this Agreement by a written instrument duly executed by both Parties.

9.3 No Third-Party Beneficiaries

This Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and where permitted, their assigns.

9.4 Waiver

9.4.1 The failure of a Party to this Agreement to insist, on any occasion, upon strict performance of any provision of this Agreement will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

9.4.2 Any waiver at any time by either Party of its rights with respect to this Agreement shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this Agreement. Termination or default of this Agreement for any reason by Interconnection Customer shall not constitute a waiver of the Interconnection Customer's legal rights to obtain an interconnection from T & D Utility. Any waiver of this Agreement shall, if requested, be provided in writing.

9.5 Entire Agreement

This Agreement, including all Exhibits, constitutes the entire Agreement between the Parties with reference to the subject matter hereof, and supersedes all prior and contemporaneous understandings or agreements, oral or written, between the Parties with respect to the subject matter of this Agreement. There are no other agreements, representations, warranties, or covenants which constitute any part of the consideration for, or any condition to, either Party's compliance with its obligations under this Agreement.

9.6 Multiple Counterparts

This Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

9.7 No Partnership

This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon either Party. Neither Party shall

have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

9.8 Severability

If any provision or portion of this Agreement shall for any reason be held or adjudged to be invalid or illegal or unenforceable by any court of competent jurisdiction or other Governmental Authority, (1) such portion or provision shall be deemed separate and independent, (2) the Parties shall negotiate in good faith to restore insofar as practicable the benefits to each Party that were affected by such ruling, and (3) the remainder of this Agreement shall remain in full force and effect.

9.9 Environmental Releases

Each Party shall notify the other Party, first orally and then in writing, of the release any hazardous substances, any asbestos or lead abatement activities, or any type of remediation activities related to the Small Generator Facility or the Interconnection Facilities, each of which may reasonably be expected to affect the other Party. The notifying Party shall (1) provide the notice as soon as practicable, provided such Party makes a good faith effort to provide the notice no later than 24 hours after such Party becomes aware of the occurrence, and (2) promptly furnish to the other Party copies of any publicly available reports filed with any governmental authorities addressing such events.

9.10 Subcontractors

Nothing in this Agreement shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this Agreement; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this Agreement in providing such services and each Party shall remain primarily liable to the other Party for the performance of such subcontractor.

9.10.1 The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this Agreement. The hiring Party shall be fully responsible to the other Party for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made; provided, however, that in no event shall T & D Utility be liable for the actions or inactions of the Interconnection Customer or its subcontractors with respect to obligations of the Interconnection Customer under this Agreement. Any applicable obligation imposed by this Agreement upon the hiring Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.

9.10.2 The obligations under this Article will not be limited in any way by any limitation of subcontractor's insurance.

Article 10. Notices

10.1 General

Unless otherwise provided in this Agreement, any written notice, demand, or request required or authorized in connection with this Agreement ("Notice") shall be deemed properly given if delivered in person, delivered by recognized national courier service, or sent by first class mail, postage prepaid, to the person specified below:

If to Interconnection Customer:

PWD Maine Utilities and Energy Manager
Bldg. 43
Portsmouth Naval Shipyard
Portsmouth, NH 03801
stephen.dakin@navy.mil
(207) 438-6625

If to T & D Utility:

Central Maine Power Company
Attention: Carol A. Purinton, Manager - Interconnection Services
83 Edison Drive
Augusta, ME 04336
Phone: 207-623-7356
Fax: 207-623-7380

With Copy to:

Legal Department
Central Maine Power Company
83 Edison Drive
Augusta, ME 04336
Phone: 207-621-6546
Fax: 207-621-6538

10.2.1 Billing and Payment

Billings and payments shall be sent to the addresses set out below:

If to Interconnection Customer:

Commander Navy Region
C/O US NAVY/4490086595011
PO Box 30088
College Station, TX 77842-3088

If to T & D Utility:

Central Maine Power Company
Attention: Carol A. Purinton, Project Manager
83 Edison Drive
Augusta, ME 04336
Phone: 207-623-7356
Fax: 207-623-7380

10.3 Designated Operating Representative

The Parties may also designate operating representatives to conduct the communications which may be necessary or convenient for the administration of this Agreement. This person will also serve as the point of contact with respect to operations and maintenance of the Party's facilities.

If to Interconnection Customer:

PWD Maine Utilities and Energy Manager
Bldg. 43
Portsmouth Naval Shipyard
Portsmouth, NH 03801
stephen.dakin@navy.mil
(207) 438-6625

If to T & D Utility:

Central Maine Power Company
Attention: Carol A. Purinton, Manager - Interconnection Services
83 Edison Drive
Augusta, ME 04336
Phone: 207-623-7356
Fax: 207-623-7380

Article 11. Signatures

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed by their respective duly authorized representatives.

For the Transmission Provider: Central Maine Power Company

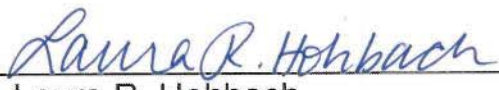
Name:  Date: 8/6/14
Eric N. Stinneford

Title: Vice-President Controller, Treasurer & Clerk

Name:  Date: 8/6/14
Carol A. Purinton

Title: Manager - interconnection Services

For the Interconnection Customer: Naval Facilities Engineering Command Mid-Atlantic on behalf of Commander Navy Region Mid-Atlantic

Name:  Date: 8/12/14
Laura R. Hohbach

Title: Contracting Officer

Exhibits (if any): Exhibit A

Exhibit A

To Level 3 Interconnection Agreement
Commander Navy Region, Mid-Atlantic
&
Central Maine Power Company

This exhibit to the Level 3 Interconnection Agreement between Naval Facilities Engineering Command Mid-Atlantic on behalf of Commander Navy Region, Mid-Atlantic ("Interconnection Customer") and Central Maine Power Company ("T&D Utility"), dated 18 July 2014, documents the following facts:

1. That the Interconnection Customer has completed the installation and interconnection of the following facilities:

Small Generator Facility, consisting of an 500 kW Battery Energy Storage System, consistent with the Interconnection Requests completed by Interconnection Customer on November 22, 2013

To T&D Utility's Electric Distribution System, and;

2. That the Interconnection Customer is required to pay the amount of \$0.00 to T&D Utility for the necessary charges described in Paragraph 4.1.1 of the Agreement for the installation and interconnection of said facilities. Future charges for the facilities, as described in Paragraph 4.1.2 of the Agreement will be billed separately to the Interconnection Customer.

Section B - Supplies or Services and Prices

ITEM NO	SUPPLIES/SERVICES	QUANTITY	UNIT	UNIT PRICE	AMOUNT
0001	Electric Svc-Navy Base Rd, Dallas PLT ME FFP Meter Number: L120153860 Contractor Account Number: 524-040-3457-001 Government Account Number: ML_PS_EL_NM_RD_001 FOB: Destination	1	Task	\$36,712.00	\$36,712.00 EST

NET AMT	\$36,712.00 (EST.)

ITEM NO	SUPPLIES/SERVICES	QUANTITY	UNIT	UNIT PRICE	AMOUNT
0002	Electric Svc - Navy Yard Line Kittery ME FFP Meter Number: AB05408218 Contractor Account Number: 449-008-6595-011 Government Account Number: ML_PS_EL_00001 FOB: Destination	1	Task	\$2,716,067.06	\$2,716,067.06 EST

NET AMT	\$2,716,067.06 (EST.)

Section E - Inspection and Acceptance

INSPECTION AND ACCEPTANCE TERMS

Supplies/services will be inspected/accepted at:

CLIN	INSPECT AT	INSPECT BY	ACCEPT AT	ACCEPT BY
0001	Destination	Government	Destination	Government
0002	Destination	Government	Destination	Government

Section F - Deliveries or Performance

DELIVERY INFORMATION

CLIN	DELIVERY DATE	QUANTITY	SHIP TO ADDRESS	UIC
0001	POP 15-MAY-2015 TO 14-MAY-2016	N/A	NAVFAC MID ATLANTIC KIMBERLY C. KAISER PWD MAINE - FEAD PORTSMOUTH PORTSMOUTH NAVAL SHIPYARD BLDG 59 PORTSMOUTH NH 03801-2032 207-438-4617 FOB: Destination	N40085
0002	POP 15-MAY-2015 TO 14-MAY-2016	N/A	NAVFAC MID ATLANTIC JACKIE JOHNSTON PWD MAINE - FEAD PORTSMOUTH PORTSMOUTH NAVAL SHIPYARD BLDG 59 PORTSMOUTH NH 03801-2032 (207) 921-1638 FOB: Destination	N40085

Section G - Contract Administration Data

BILLING INFORMATION

Navy bills are to be mailed directly from the vendor/utility provider to the Navy's vendor (Heartland Energy Partners) for processing at the address shown below. Therefore, the "Bill To" and/or "Mail To" should be addressed as follows:

Utility Invoice Processing Center

***(Insert respective Government Account Number)**

Box 159

9226 Third Avenue

Norfolk VA 23511-2313

The Government account number that corresponds to your account number has been provided in the table below titled, "LIST OF SERVICE POINTS." Please note: The mailing address MUST include the respective Government Account Number(s).

LIST OF SERVICE POINTS

Contractor Account Number	Government Account Number	Meter Number	Service Location	Tariff Schedule	Prior Contract No.
524-040-3457-001	ML_PS_EL_NM_RD_001	L120153860	Navy Base Rd – Dallas PLT ME	MGS-P-TOU	N62470-94-C-9429
449-008-6595-011	ML_PS_EL_00001	AB05408218	Navy Yard Line, Kittery, ME	LGS-P-TOU	N62470-94-C-9542

Section I - Contract Clauses

CLAUSES INCORPORATED BY REFERENCE

52.204-10	Reporting Executive Compensation and First-Tier Subcontract Awards	JUL 2013
52.225-13	Restrictions on Certain Foreign Purchases	JUN 2008
52.225-20	Prohibition on Conducting Restricted Business Operations in Sudan--Certification	AUG 2009
52.225-25	Prohibition on Contracting with Entities Engaging in Certain Activities or Transactions Relating to Iran-- Representation and Certifications.	DEC 2012
52.232-33	Payment by Electronic Funds Transfer--System for Award Management	JUL 2013
52.233-3	Protest After Award	AUG 1996
52.233-4	Applicable Law for Breach of Contract Claim	OCT 2004
52.236-5	Material and Workmanship	APR 1984
52.241-4	Change in Class of Service	FEB 1995
52.241-5	Contractor's Facilities	FEB 1995
52.241-11	Multiple Service Locations	FEB 1995
52.243-1 Alt II	Changes--Fixed-Price (Aug 1987) - Alternate II	APR 1984
52.249-8	Default (Fixed-Price Supply & Service)	APR 1984
252.203-7000	Requirements Relating to Compensation of Former DoD Officials	SEP 2011
252.203-7001	Prohibition On Persons Convicted of Fraud or Other Defense-Contract-Related Felonies	DEC 2008
252.204-7003	Control Of Government Personnel Work Product	APR 1992
252.204-7004 Alt A	System for Award Management Alternate A	FEB 2014
252.241-7001	Government Access	DEC 1991

CLAUSES INCORPORATED BY FULL TEXT

52.241-3 SCOPE AND DURATION OF CONTRACT (FEB 1995)

(a) For the period 15 May 2015 through 14 May 2016 the Contractor agrees to furnish and the Government agrees to purchase electric utility service in accordance with the applicable tariff(s), rules, and regulations as approved by the applicable governing regulatory body and as set forth in the contract.

(b) It is expressly understood that neither the Contractor nor the Government is under any obligation to continue any service under the terms and conditions of this contract beyond the expiration date.

(c) The Contractor shall provide the Government with one complete set of rates, terms, and conditions of service which are in effect as of the date of this contract and any subsequently approved rates.

(d) The Contractor shall be paid at the applicable rate(s) under the tariff and the Government shall be liable for the minimum monthly charge, if any, specified in this contract commencing with the period in which service is initially furnished and continuing for the term of this contract. Any minimum monthly charge specified in this contract shall be equitably prorated for the periods in which commencement and termination of this contract become effective.

(End of clause)

52.241-6 SERVICE PROVISIONS (FEB 1995)

(a) Measurement of service. (1) All service furnished by the Contractor shall be measured by suitable metering equipment of standard manufacture, to be furnished, installed, maintained, repaired, calibrated, and read by the Contractor at its expense. When more than a single meter is installed at a service location, the readings thereof may be billed conjunctively, if appropriate. In the event any meter fails to register (or registers incorrectly) the service furnished, the parties shall agree upon the length of time of meter malfunction and the quantity of service delivered during such period of time. An appropriate adjustment shall be made to the next invoice for the purpose of correcting such errors. However, any meter which registers not more than the amount specified by contractor's applicable governing body as measured in terms of percent slow or fast shall be deemed correct.

(2) The Contractor shall read all meters at periodic intervals of approximately 30 days or in accordance with the policy of the cognizant regulatory body or applicable bylaws. All billings based on meter readings of less than the amount specified by contractor's applicable governing body as measured in terms of days shall be prorated accordingly.

(b) Meter test. (1) The Contractor, at its expense, shall periodically inspect and test Contractor-installed meters at intervals not exceeding the amount specified by contractor's applicable governing body as measured in terms of year(s) The Government has the right to have representation during the inspection and test.

(2) At the written request of the Contracting Officer, the Contractor shall make additional tests of any or all such meters in the presence of Government representatives. The cost of such additional tests shall be borne by the Government if the percentage of errors is found to be not more than the amount specified by contractor's applicable governing body as measured in terms of percent slow or fast.

(3) No meter shall be placed in service or allowed to remain in service which has an error in registration in excess of the amount specified by contractor's applicable governing body as measured in terms of percent under normal operating conditions.

(c) Change in volume or character. Reasonable notice shall be given by the Contracting Officer to the Contractor regarding any material changes anticipated in the volume or characteristics of the utility service required at each location.

(d) Continuity of service and consumption. The Contractor shall use reasonable diligence to provide a regular and uninterrupted supply of service at each service location, but shall not be liable for damages, breach of contract or otherwise, to the Government for failure, suspension, diminution, or other variations of service occasioned by or in consequence of any cause beyond the control of the Contractor, including but not limited to acts of God or of the public enemy, fires, floods, earthquakes, or other catastrophe, strikes, or failure or breakdown of transmission or other facilities. If any such failure, suspension, diminution, or other variation of service shall aggregate more than the amount specified by contractor's applicable governing body as measured in terms of hour(s) during any billing period hereunder, an equitable adjustment shall be made in the monthly billing specified in this contract (including the minimum monthly charge).

(End of clause)

As allowed by FAR 41.501 (d), the following terms and conditions apply to this task order. The terms and conditions are substantially the same as FAR 52.241-7 CHANGE IN RATES OR TERMS AND CONDITIONS OF SERVICE FOR REGULATED SERVICES (FEB 1995):

(a) This clause applies to the extent services furnished under this contract are subject to regulation by a regulatory

body. In the same manner that it notifies all other customers of proposed changes to its filed tariffs, the Contractor agrees to give notice of

(1) the filing of an application for change in rates or terms and conditions of service concurrently with the filing of the application and

(2) any changes pending with the regulatory body as of the date of contract award. Such notice shall fully describe the proposed change. The Contractor agrees to continue furnishing service under this contract in accordance with the amended tariff, and the Government agrees to pay for such service at the higher or lower rates as of the date when such rates are made effective.

(b) The Contractor agrees that throughout the life of this contract the applicable published and unpublished rate schedule(s) shall not be in excess of the lowest cost published and unpublished rate schedule(s) available to any other customers of the same class under similar conditions of use and service.

(c) Any changes to rates or terms and conditions of service shall be made a part of this contract upon approval of such changes by the applicable regulatory body. The effective date of the change shall be the effective date by the regulatory body. Any factors not governed by the regulatory body will have an effective date as agreed to by the parties.

252.241-7000 SUPERSEDING CONTRACT. (DEC 1991)

This contract supersedes contract No. N62470-94-C-9429 and N62470-94-C-9542 which provided similar services. Any capital credits accrued to the Government, any remaining credits due to the Government under the connection charge, or any termination liability are transferred to this contract.

(End of clause)

5252.201-9300 CONTRACTING OFFICER AUTHORITY (JUN 1994)

In no event shall any understanding or agreement between the Contractor and any Government employee other than the Contracting Officer on any contract, modification, change order, letter or verbal direction to the Contractor be effective or binding upon the Government. All such actions must be formalized by a proper contractual document executed by an appointed Contracting Officer. The Contractor is hereby put on notice that in the event a Government employee other than the Contracting Officer directs a change in the work to be performed, it is the Contractor's responsibility to make inquiry of the Contracting Officer before making the deviation. Payments will not be made without being authorized by an appointed Contracting Officer with the legal authority to bind the Government.

Section J - List of Documents, Exhibits and Other Attachments

EXHIBIT A

Central Maine Power Company
AUTHORIZATION FOR ELECTRIC SERVICE, CHANGE IN ELECTRIC SERVICE, OR DISCONNECTION OF
ELECTRIC SERVICE UNDER
CONTRACT NO. GS-00P-06-BSD-0466

Ordering Agency: Naval Facilities Engineering Command Mid-AtlanticAddress: 9324 Maryland Ave Norfolk, VA 23511-3095

Pursuant to Contract No. GS-00P-06-BSD-0466 between the Contractor and the United States Government and subject to all the provisions thereof, service to the United States Government under such contract shall be rendered or modified as hereinafter stated. Contract Article 2 and 4 shall be followed for the initiation of service under this contract.

PREMISES TO BE SERVED: See Service Locations set forth in Section G above.SERVICE ADDRESS: See Service Locations set forth in Section G above.NATURE OF SERVICE: Continue ServiceOTHER TERMS AND CONDITIONS: See terms and conditions set forth above.POINT OF DELIVERY: See Section G above. Delivery points may be added by modification to this orderTERM OF SERVICE: See Section F above

SERVICE HEREUNDER SHALL BE UNDER RATE SCHEDULE NO. LGS ST TOU and MGS-P-TOU * Hereafter amended or modified by the regulatory body having jurisdiction. (see article 5 of this contract.)

For LGS P TOU:ESTIMATED ANNUAL ENERGY USAGE: 25,305,000.00 kWhESTIMATED ANNUAL SERVICE COST: \$2,716,067.06ESTIMATED CONNECTION/SPECIAL FACILITIES CHARGE: \$ 0.00ACCOUNTING AND APPROPRIATION DATA FOR SERVICE: Operations and Maintenance, Navy funds provided separatelyFOR CONNECTION/SPECIAL FACILITIES CHARGE: \$ 0.00For MGS P TOU:ESTIMATED ANNUAL ENERGY USAGE: 311,760 kWhESTIMATED ANNUAL SERVICE COST: \$35,712.00ESTIMATED CONNECTION/SPECIAL FACILITIES CHARGE: \$ 0.00ACCOUNTING AND APPROPRIATION DATA FOR SERVICE: Operations and Maintenance, Navy funds provided separatelyFOR CONNECTION/SPECIAL FACILITIES CHARGE: \$ 0.00CLAUSES INCORPORATED BY REFERENCE: See clauses incorporated above.

BILLS WILL BE RENDERED TO THE ORDERING AGENCY FOR PAYMENT AS SHOWN IN SECTION G OF THIS TASK ORDER.

The foregoing shall be effective upon the return of the fully executed original Authorization by the Contractor to the ordering Agency.

ACCEPTED:

NAVFAC MIDLANT
 (Ordering Agency)
 By: [Signature]
 (Authorized Signature)
 Title: Contracting Officer
 Date: 5/13/15

Central Maine Power Company
 (Contractor)
 By: [Signature]
 (Authorized Signature)
 Title: President & CEO
 Date: _____

*CMP rate schedules are available at <http://www.cmpco.com/YourHome/pricing/pricingSchedules/default.html>

Designated Entity (DE) Responsibility Checklist

Instructions

Please review the Definitions below. This Checklist is to be completed by the Operations Management contact of the DE.

After reading the definitions, please proceed to the Checklist on page 2 and check each box to acknowledge the equipment and staffing capabilities to perform as a DE based on the asset(s) and its capabilities being managed for dispatch. **Only check a box if you meet the requirement for all assets with that capability. If the DE does not meet the item for each asset, then the box should be left unchecked.** The 1st column applies to for any DE regardless of asset capabilities. Other columns apply if the DE is responsible for at least one asset with that capability. Some items may not apply or indicate that a waiver may be an option. DEs are subject to audit to verify compliance.

EDC = Electronic Dispatch Capable

AGC = Automatic Generator Control

BS = Black Start Capable resource

FS = Fast Start (ie Claim 10 and/or Claim 30)

PSS = Power System Stabilizer

Definitions:

Designated Entity (DE):

The person or organization which is continuously available, designated by the Lead Market Participant of a Generator, in accordance with the notice provisions set forth in ISO New England Operating Procedure No. 14, to receive Dispatch Instructions for generation and/or Dispatchable Asset Related Demand. The Designated Entity is the only entity to which the ISO will communicate Dispatch Instructions. (Per OP 14)

DE Location:

Physical location of the Designated Entity (DE) which is a fixed location in the continental United States

Electronic Dispatch Capability (EDC)

The ability, through the installation and maintenance of adequate hardware and software and communications infrastructure within the Continental United States, to provide for the electronic transmission, receipt, and acknowledgment of data relative to the dispatch of Generators to carry out the real-time dispatch processes from ISO issuance of Dispatch Instructions to the actual increase or decrease in output of dispatchable Generators. Generators are considered to have EDC when they are capable of receiving, responding to, and changing output in response to electronic Dispatch Instructions issued to the ISO Communications Front End (CFE) connected Remote Terminal Unit (RTU) of its DE. (OP 14 II.A.7)

Remote Terminal Unit (RTU)

A communication system (hardware and software) that enables a DE to receive, acknowledge, and implement ISO dispatch instructions electronically 24 hours a day, 7 days a week. (See Electronic Dispatch Capability)

Dedicated Voice Communication Telephone

A continuously manned voice communication line which is used exclusively for ISO New England Dispatch and dispatch-related purposes. Also referred to as Dedicated Bell Line (DBL).

Auto Ring Down circuit (ARD)

A continuously manned voice communication circuit which instantaneously connects the ISO directly to the DE

Approved Mode of Communication for all ISO Directives received over ARD or Dedicated Communication Circuits:

In accordance with [NERC Reliability Standard COM-002-2](#) Requirement #2 all directives shall take place as follows:

“Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall issue directives in a clear, concise, and definitive manner; shall ensure **the recipient of the directive repeats the information back correctly**; and shall acknowledge the response as correct or repeat the original statement to resolve any misunderstandings.”

This [NERC Reliability Standard](#) is applicable to all Reliability, Balancing, Transmission and Generator Operators.

ALL	EDC	AGC	BS	FS	PSS	A Designated Entity shall be able to provide or shall possess:
☒						1. Communications equipment, hardware, & software required to receive, acknowledge receipt and implement ISO dispatch instructions in a timely manner: (OP14 II.A.7 & II.C.3)
☐	☒					a. ISO Connected RTU (Communications Front End – CFE) (OP18.V.A.1)
☐						b. Generator net MW measured on low side of GSU with 10 second scan rate (OP18V.A.1 & V.C.2)
☐						c. Generator net MVAR measured on low side of GSU with 10 second scan rate (OP18 V.A.1 & V.C.2) (OP12IV.A.)
☐						d. Generator Breaker Status with 4 second scan rate (OP 18 V.A.1. & V.C.1)
						e. AVR Indicator that displays mode and voltage with a 10 second scan rate (or has AVR exemption) (OP18 .C.2)(OP12IV.A.)
		☒				f. If Regulation Capable, Regulation transducer with 4 second scan rate (OP 18 V.C.1)
	☒					2. Points of contact ≤ # ISO CFE connected RTUs for receipt of Electronic Dispatch instructions (OP14 II.A.7)
	☒					3. Electronic Dispatch Capability (EDC) Installed. (OP14 II.A.7)
☒						4. Knowledge of DE Registration Requirements. (OP14 II.C)
	☒					5. Controlling ≤ 5 Generating units with a single ISO connected RTU. (OP14 II.A.2)
☒						6. Dedicated Voice Communication Circuit (OP14 IIC.2.)
	☐	☐				7. Dedicated Auto Ring Down Circuit (Sum of EDC Assets ≥ 50MW or at least one unit AGC) (OP14 IIC.2.)
						8. Display of following parameters for each generator dispatched: (OP 14 II.C.4.)
	☐					a. Acknowledgement Required (OP 14 II.C.4.)
	☐					b. Message Type (all of the following) (OP 14 II.C.4.)
	☐					i. Normal (OP 14 II.C.4.)
	☐					ii. Emergency (OP 14 II.C.4.)
	☐					iii. Start up (OP 14 II.C.4.)
	☐					iv. Shut down (OP 14 II.C.4.)
	☐					c. Desired Dispatch Point (DDP) (OP 14 II.C.4.)
	☐					d. Actual Generation (OP 14 II.C.4.)
	☐					e. Economic Minimum Limit (OP 14 II.C.4.)
	☐					f. Economic Maximum Limit (OP 14 II.C.4.)
	☐					g. Emergency Minimum Limit (OP 14 II.C.4.)
	☐					h. Response Rate Manual and Regulation(OP 14 II.C.4.)
		☒				i. If Regulation Capable, Regulation High Limit (OP 14 II.C.4.)
		☒				j. If Regulation Capable, Regulation Low Limit (OP 14 II.C.4.)
	☐					k. Unit Control Mode (OP 14 II.C.4.)
	☐					l. Heartbeat (state of ED signal) (OP 14 II.C.4.)
☒						9. Staff on duty to communicate with ISO System Operators at all times (OP 14.II.C.5)
	☒					10. Understand that Verbal dispatch orders from ISO New England take precedence over EDC (OP 14 II.C.8)
☒						a. Repeat all ISO directives back to ISO correctly; ISO shall acknowledge the response as correct or repeat the original statement to resolve any misunderstanding (NERC COM-002-2 B.R2.)
☒						11. Redecclare offer data as soon as practicable (M-11 2.5.3.27.b)(M-11.3.2.1.6) (OP 14 II.F.1)
				☐		12. (Fast Starts Units) Manually acknowledge Start up signal within 60 seconds and comply immediately <i>requiring physical action by staff at the D</i> ; or have exemption to allow electronic acknowledgement for Auto-start unit(s). (OP 14.II.F.2) *
				☐		13. (Fast Start Units) Manually acknowledge Shut down signal within 60 seconds and comply immediately <i>requiring physical action by staff at the D</i> ; or have exemption to allow electronic acknowledgement for Auto-start unit(s). (OP 14.II.F.2) *
	☒					14. Manually acknowledge Emergency Messages within 60 seconds and comply without delay. <i>This acknowledgement requires physical action by staff at the DE immediately requiring physical action by staff at the D</i> ; or have exemption to allow electronic acknowledgement for Auto-start unit(s). (OP 14.II.F.3) *
	☐					15. Emergency Messages are displayed with unique audible and visual displays for each generator (OP 14 II.E.1)
		☐				16. Understand that units on Regulation to be taken off and follow Emergency DDP (OP 14.II.F.3)
☐						17. Will notify ISO and LCC whenever AVR taken OOS, shall set to control voltage in accordance with a voltage schedule provided by the Local Control Center, and shall not allow voltage regulator to be overridden by any supplemental control system; or have AVR exemption (OP 14 II.H, OP12 IV.A & Appendix B)
					☐	18. If Power System Stabilizer (PSS) equipped, maintain PSS in good operating condition and promptly report any problems w/ PSS operation. Operate in or out of service as appropriate. Promptly report if PSS status (in/out of service) is to be changed. (OP 14 II.L; M/LCC 8)
			☐			19. Notify ISO of problems with Black Start Capability (if Dedicated Blackstart Resource) (OP 14 II.M)
☒						20. Respond to verbal instructions of LCC System Operators (OP12 IV.A)

Comments - Designated Entity Responsibility Checklist

DE #: TBD

DE Name: Ameresco_DE_Portsmouth_BESS

Asset#: 43730

Asset Name: Ameresco_Portsmouth_Naval_BESS

- 1
 - a. Y RTU
 - b. N Not a generator
 - c. N Not a generator
 - d. N Not a generator
 - e. N Not applicable
 - f. Y Unit on Regulation as ATRR
- 2 Y 1 RTU - 1 POC
- 3 Y Only for Regulation Market, Not as a generator
- 4 Y Recongizing 4 Forms provided by Jon Lowell 01/31/14, no ATRR in OP14 or m-RPA
- 5 Y 1 to 1
- 6 Y Phone manned 24/7, control room line, not Dedicated
- 7 N Technical and Financial burden for a asset $\leq$ 1MW
- 8 Y See below for Section 8.
 - a.
 - b. *Each DE is required to display to their DE Operator, the following parameters for each ATRR, as defined in OP 14 DRAFT - Section III.A.4*
 - i.
 - ii.
 - iii. *a. AGC Setpoint*
 - iv. *b. Actual Injection / Consumption*
 - c. *c. Response Rate*
 - d. *d. Regulation High Limit*
 - e. *e. Regulation Low Limit*
 - f. *f. ATRR Availability*
 - g. *g. On Regulation Status*
 - h. *h. Heartbeat*
 - i.
 - j.
 - k.
 - l.
- 9 Y Staff available by phone 24/7, prompt technician dispatch
- 10 Y
 - a. Y Visual display for confirmation of signal received from ISO
- 11 Y Ability to contact ISO to declare offer
- 12 N
- 13 N
- 14 N Request exemption, to allow electronic acknowledgement
- 15 N Refer back up to item 8.
- 16 N ATRR Not participating in Emergency DDP
- 17 N
- 18 N
- 19 N
- 20 Y LCC will have same phone number as in item 6.

APPENDIX K - BESS FIELD QUALITY ISSUE TRACKING SHEET

No.	Date of Entry	PROBLEM	STATUS	ROOT CAUSE	CORRECTIVE ACTION	PREVENTIVE ACTION	Notes
1	10/19/2015	(5) FSS Sensors Reporting Trouble Faults First Fault Occurrences: Sensor 1-06 08/22/2016 Sensor 1-12 09/30/2016 Sensor 1-13 08/25/2016 Sensor 1-15 10/19/2015 Sensor 1-16 07/18/2016) System was rendered unoperational for a period of 2-4 weeks at the time of each failure due to 3rd party controller following monitoring and control specifications provided by Saft.	CLOSED	-10/4/16: Saft notes that this is a global quality issue. RCI underway but not complete Ameresco speculates both the high humidity conditions and placement of sensors could have caused failures, but we need Saft to properly root cause.	All sensors were replaced with a new model	Sensor cleaning required annually per Doc HPF-11 Cleaning Procedure sent by SAFT. Note:	-10/4/16: Saft will determine if 6 sensors are available for containment replacement, with answer by 10/5 AM -10/5/16: Nicole reports new sensors will ship by 10/6. -01/04/17: Zone 07 was removed in Dec '16 and Saft says WW Gay has approved the determination that it does not need to be replaced. -01/31/2017: Saft verbally communicated that the "No field repair of the detectors..." statement only applies to the "Sensing Chamber" module (which should never be opened) but Saft states cleaning in the field is
2	9/20/2016	Battery strings 2,4,5,8 and 9 are open and won't connect to DC bus	OPEN	Saft technician discovered shunt trips were inoperable and showed physical signs of damage/discoloration 01/04/17: Saft reports defective ABB breakers as RC and not caught before shipment. AMRC voices some disagreement and requests further root cause investigation 01/31/17: Saft reports 2-3% failure of shunt trip manufacturing on ABB breakers	All 5 modules that were replaced on November 02 by Robert and returned to SAFT	Not yet taken. What testing or action was put in place to prevent failed parts from shipping to customer?	Saft tech discovered burned shunt relay within breaker. -10/4/2016: Saft's engineering point of view is that the system could operate. But, Ameresco's stance is we can't assume that safety risk 12/8/2016: AMRC still has concerns about the risk of the other 5 modules 01/31/2016: SAFT to conduct 8D root cause investigation and provide report to Ameresco
3	12/3/2014	ABB Breaker - DC Breaker will not close	CLOSED	Undetermined	Replaced under warranty	Not yet taken	
4	10/1/2014	After replacing SMUs, Tech was attempting to balance battery modules but was unable to balance some modules. Found defective battery cells in those modules.	CLOSED	Diagnosed to be a cell issue, but exact cause unknown	Replaced 2 Modules Nov 2015	Not yet taken	Resolution of this issue also improved power capability at high and low SOC
5	9/1/2014	Battery strings were tripping and unable to be reset.	CLOSED	SMUs had component failures, suspected to be attributed to PCB Manufacturer.	Replaced all 290 SMU boards	Not yet taken	
6	Aug/Sept 2014	FSS Sensor and Air Plenum - Sensor placement in relation to plenum openings does not meet sensor manufacturer's suggested operating environment.	CLOSED	Undetermined	SAFT moved multiple sensors and field modified the plenum.	Not yet taken	Photos of pre-existing conditions are available upon request.
7	July/Aug 2014	High levels of moisture and puddling of water found in container	OPEN	Dehumidification system was not programmed or set up for operation as part of installation	No Action was taken. Puddles naturally evaporated Oct-2016: Robert (Saft tech) discovered HVAC unit had never been properly wired or programmed in factory. He corrected on site.	Not yet taken	delivery of unit if we need desacent. No response from Saft. -Humidity remained high in container even after evaporation.(e.g. phenolic labels would not stick) -After Robert programmed humidification, labels properly adhere. -Troy has photos of corrosion presence in container. -AMRC calculates ~2quarts of water removed in 1-2 days after humidification settings were enabled 1/4/17: AMRC requests Capacity Test be performed to verify remaining capacity of system in response to concerns about cell health. Saft sent test procedure to AMRC. AMRC also requests 1 year extension of warranty based upon concerns of possible damage to components and electrical equipment after prolonged exposure to life. Saft to review request with management 01/31/2017: Saft and AMRC agreed to have Saft field technician conduct field assessment of the state of components

APPENDIX I - POWER PLANT INTERACTION REPORT



Electrical Engineering Services



Ameresco/GE/Solar/Diesel Fast Load Shed Interaction Report

**Portsmouth Naval Shipyard
GE Fast Load Shed System
SGC Project #1109003**

Prepared by:
SGC ENGINEERING
8/24/2015
Rev.1

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1. Executive Summary

The Portsmouth Naval Shipyard (PNS) has the ability to fulfill its power requirements from multiple different sources. Central Maine Power (CMP) provides power from the grid via the Franklin and Franklin Annex substations. PNS also has various distributed resources including (2) 5 MW combustion turbine generators (CTG) and (2) 2 MW diesel generators. (DGEN). Under normal conditions, the two CTGs run continuously to reduce power imported from CMP. When PNS is disconnected from the grid via two utility breakers opening at Franklin and Franklin Annex, a signal is sent to the DGENs and the CTGs. That signal starts the DGENS and forces the CTGs into island mode and they begin to regulate frequency. When the DGENS come online, after a short delay to allow their frequency to stabilize, they lock onto the frequency provided by the CTGs and add capacity to the local distributed generation. This scenario is sustainable as long as the load of PNS is less than the power available from all on line generation sources. If, when in island mode, the load at PNS exceeds the total generation capacity of the two CTGs (before the DGENS are on line), one of the CTGs will trip on under frequency (81U) and cause a cascading failure event where the other CTG will also collapse and cause a PNS wide blackout.

The GE Fast Load Shed system is designed to prevent this scenario by shedding just enough load to keep the on line distributed sources up and running. This is done by monitoring the loads on selected PNS feeders as well as the total spinning reserves of the CTGs. The spinning reserve is the amount of power the CTGs can produce according to present turbine and atmospheric conditions. A user selected preset algorithm in the GE system calculates which loads can be shed in order to keep the load under the total amount of power available. This keeps the distributed resources on line and avoids a cascading generator trip event and blackout. Once the DGENS spool up, synchronize with the CTGs, and are back online, additional loads that had been previously shed via the GE FLS can be brought back online.

This report investigates the interaction of the power loads and power production systems to ensure the FLS operation will be seamless. It is recommended a few operational changes at the CTGs (Section 4) and the GE FLS system (Section 5) be made. With these changes and a very fast communications system, this goal can be achieved.

2. Load Share Operational Description

Each of the generation (CTG1, CTG2, DG1, DG2) sources proportionally share the load via a Woodward 2301A (or compatible) Load Sharing module (LSM). This device operates much like a voltage divider. Each LSM is electrically daisy chained to the others in the load sharing system. The LSMs are adjusted on an individual basis per generator. The full voltage of the LSM is scaled proportional to the full load of each individual generator. This ensures proportional load sharing regardless of the differences in generator size.

There are two basic modes used for paralleling generation sources: droop mode, where speed decreases with load, and island mode, where speed (therefore frequency) remains constant. Only the island mode will be discussed here. For a description of droop mode paralleling, see the LSM manual in Section 10 of this document.

The LSM paralleling system consists of a load matching circuit and a load amplifier circuit. As discussed above in section 1, auxiliary contacts on the utility tie breakers are used, in series, to select island mode load-sharing operation.



In island mode, the internal LSM load-sharing-line relay is energized, the droop signal is disabled permitting island mode load sharing, and the load-matching circuit is connected to the load-sharing lines delivering equal reference voltage to all generators in the LSM system.

With only one CTG online, it would pick up the available load (as long as the load was less than the capacity of the generator) and remain at island (synchronous) speed. If additional units are online, the load matching circuit corrects the fuel input to proportion the load via a remote speed set point input. An amplifier in the load-sensing circuit computes the load carried by each phase of the generator. The current load on each phase is multiplied by the cosine of the phase difference between the current and the voltage, and the three phases are added to determine the total load. The output of the load amplifier is adjusted and fine tuned with the load gain potentiometer. By setting the load-gain voltage on each unit to the same level at full load, proportional load sharing is achieved. Regardless of differences in generator-set capacities in the system, each generator set is loaded to the same percentage of its capacity. DG1, DG2, CTG1, and CTG2 will now all receive the same load reference voltage and share their loads proportionally.

3. Island Mode Signal to CTGs

The CTGs and DGENs get their signal that the utility breakers, F1 and F12 (via series wired 52b contacts), are open, and hence PNS is now in island mode, from the CR934 follower relay in the Prime Automation (PA) cabinet. There is a cable that runs directly from the PA cabinet to the F1 and F12 auxiliary contacts for this purpose. During the FLS installation, a new relay, 94UFLS, will be installed and will operate upon loss of utility via these contacts. This new relay will indicate loss of utility to the FLS system located in the Franklin sub and also duplicate the existing signal to energize the existing CR934 follower relay. All systems connected to the existing CR934 will operate normally.

The cables that run to the CTGs, to indicate loss of utility, have been traced directly to CR934 in the PA cabinet. It should be noted that while investigating this signal, spare conductors were found in CTG 1 that were labeled as going to Franklin sub, Cubicle 1, A contacts. This cable, after investigation on the Franklin end, was found to be located in Cubicle 0B. These were the original conductors used for the island signal before the Prime Automation cabinet was installed. This can be seen on SGC drawing 110900485, Solar drawing 5789-149480, 72981-149320, and Prime Automation 0019-SCH, Sh. 9 in Appendix A of this document.

4. Alterations to the CTG system

In order to allow adequate time for the distributed resources to maintain power production and prevent a PNS blackout, the FLS system must react fast enough to prevent the CTGs from going into an overload situation and going off line. This can be achieved in two ways. The first way is to ensure the FLS is fast enough to shed enough load before an overload condition occurs. By combining the reaction times of the relays, processors, fiber optics, trip relays, and breaker clearing time, it has been determined that the FLS system can respond in a timely manner and prevent a blackout. See Table 1 for a time comparison time line. The second way to ensure the CTG system will allow enough time for the FLS to operate is to ensure the T5 control on the CTG system remain in the "on" state during an islanding situation. The T5 control is the temperature control system that detects a fuel overload and over temperature in the T5



stage of the turbine. When the T5 control system alarms (High-High) due to excessive fuel use and over temperature, the CTG system shuts down immediately. There are two levels to the T5 control, a High, with a 20-30 second delay before shutdown, and a High-High, that acts almost instantly with no preset delay. Presently, when the CTGs are grid tied, the T5 control limits the power produced by the CTGs. When islanded, the T5 control is not active and an overload situation is indicated by under frequency.

Setting the parameters on the T5 control to remain “on” during an islanding event will regulate the temperature, and therefore the fuel input, to prevent immediate shutdown and cascading failure due to overload. It is fairly difficult to overload a CTG with the T5 control on. This change will give the FLS the extra cycles to guarantee a complete shedding process and ensure the DGENs have adequate time to spool up. Solar has agreed to make this change on Ameresco’s behalf to ensure this system works properly.

The CTG system will still trip on under frequency, even if the T5 control is “on”, it is just delayed, so it is imperative that the FLS system shed load in time to ensure frequency stability. As shown in Table 1, the FLS system is still more than 3 times faster than it needs to be considering the present 81U settings of the CTG system, but adding the T5 control in island mode will give more time for the DGENs to spool up and ensure a quick restoration of the PNS grid. **The BESS system will assist in this as the FLS system will command the system into discharge AVR mode immediately upon detecting loss of utility.** This quick and immediate burst of power will help the CTG system ride through the start up period of the DGENs.

The timing of the tripping processes is listed in Table 1. Please note that this timing table assumes worst case scenario and uses the slowest times possible for the FLS system and the quickest times for the CTG system. For the purposes of this table, it is assumed that electricity propagates on copper and fiber at the same speeds and thus can be cancelled from each equation. Copper can be anywhere from 50 to 90% as fast as fiber, but the differences are insignificant compared to the overall times and on the order of microseconds. This worst case scenario assumption will add to the safety factor of the FLS system shedding breakers in time to ensure the CTG system continues to stay on line and providing power.

CTG timing (mS)	Comments	FLS timing (mS)
0	52 contact on Utility breakers F1 and F12 operate	0
16	CTG 1 81U GE electromechanical protective relay 12SFF32A1A detects an 81U condition assuming frequency is below 58 Hz. Worst case assuming frequency is below 58 on loss of utility.	
22	Interposing relay 94UFLS operates and sends signal via copper to local FLS panel and to F1 follower relay CR934 in Prime Automation cabinet.	22
	FLS system recognizes input from 94UFLS.	23
	F-F35-1 relay at Franklin logic processing complete.	25
	F-F35-1 relay sends GOOSE message via fiber indicating utility separation has occurred.	31
	GOOSE message received by C90+ Automation Controller.	32
	GOOSE message processed by C90+	38
	C90+ logic processing complete.	39
	GOOSE message issued by C90+ and transmitted via fiber to appropriate X-F35-X closest to breaker that will be shed.	45
	X-F35-X receives GOOSE message to shed.	46
47	F1 follower relay CR934 operates and sends loss of utility signal to both CTG interposing relays (K205) via copper.	
	X-F35-X processes GOOSE message to shed.	52
	X-F35-X logic processing complete.	54
57	CTG loss of utility interposing relays (K205) operate and relay signal via copper to PLCs via Flex I/O input ZF2051, channel 2.	
	X-F35-X form A contact operates and energizes trip coil via copper. GE exclusively uses these form A contacts instead of the form C contacts as they are twice as fast.	58
62	CTG PLC input is recognized.	



70	CTG 1 81U GE electromechanical protective relay 12SFF32A1A operates. There is no reported time delay on this relay. GE manual GEK- 49923 states operate time of 70 ms but relay testing sheets report an operation time of 407 mS worst case. This relay will be used as worst case as CTG 2 81U has a delay of 2500 mS under 58 Hz.	
75	PLC implements logic after first scan. CTG 1 has PLC 5 with scan time of 28 mS. CTG 2 has Control Logix platform with scan time of 13 mS which was used here. CTGs are now in island mode.	
120	If 81U relay operated per the timing in the GE instruction manual, this is when generator breaker would open assuming 3 cycle operation. This would be the worst case scenario and is probably closer to 5 cycles. At 5 cycles, the generator breaker would be open at 150 mS.	
	Trip coil of selected load shed breaker operates and breaker is open. This is based on worst case timing of 5 cycles from trip signal received to breaker open.	141
407	CTG 1 81U protective relay operates as per the test reports assuming 81U is immediately detected at initial loss of utility. (< 58 Hz) 81U relay sends trip signal via copper to CTG 1 generator breaker	
457	Generator breaker opens and CTG 1 goes off line. This is using the optimistic operating time of 3 cycles for the breaker and is probably closer to 5 cycles.	
2530	CTG 2 CGCM 81U relay send signal to trip CTG 2 generator breaker via copper. This value is based on test reports.	
2580	CTG 2 breaker opens and CTG 2 goes off line assuming < 58 Hz on initial loss of utility. This is based on best case scenario of 3 cycle breaker operate time.	

Table 1. FLS and CTG operating timing comparisons

5. Alterations to the GE FLS system

After discussions with the Solar regional technical manager, a few options were suggested for the FLS system to ensure proper operation. Because the PNS system is dynamic and the CTGs spinning reserves (amount of load head room before maximum load is reached based on present turbine and atmospheric conditions) change with atmospheric conditions, it was suggested that the FLS system continue to monitor the spinning reserves of the distributed generation and initiate further load sheds as needed even after the initial load shed event. In addition to monitoring the spinning reserves of the distributed generation after the initial shed event, a suggestion was made that the FLS should monitor frequency on the PNS system and shed on an 81U event, low frequency. The suggested 81U frequency level to initiate the second tier of load sheds was 57 Hertz.

It was also suggested that instead of a definite 81U cutoff level, a frequency rate of change could be used. The faster the drop in frequency (or use steps of frequency if rate of change is not available, the bigger the step, the faster the trip), the faster the FLS would shed the load when it arrived at the 81U trip point.

6. Power Plant BOP communications and A/B tag retrieval

In Section 11, some of the tags available (there are many more available, but have not been used before and therefore are not listed) in the BOP system have been listed. Existing tags of interest to the GE team might be load1pct, load2pct, DG1LC, DG2LC, TG1LC, TG2LC, DG1_LF, DG2_LF, TG1_LF and TG2_LF. These are all load type points for the generation machines. There are actual loads, percentage loads, and demand loads. The tags for the CTG values of spinning reserves were not apparent when looking through the list. After discussions with I and C Engineering of Newburyport, MA (ph. 978-465-2220), and specifically Bob Long (617-308-1528), the BOP PLC system was found to not contain any premade MODBUS registers. The entire PNS power system is operating as an Allen Bradley system as the BOP,



CTG, and DGEN control systems are all Allen Bradley platforms. Any tags (as in spinning reserves) from the CTG systems that are requested to be used by GE must be retrieved from the A/B CTG control platforms (PLC5 (CTG 1) and ControlLogix (CTG 2)), stored in an A/B register, and then placed in the FLS system where ever required and in whatever order GE requests.

The DGEN system presently has a connection with the A/B BOP system. The DGEN system has three A/B control platforms, one for DGEN 1, one for DGEN 2, and one for DGEN 1 and DGEN 2 common items. The BOP system only issues commands to the DGEN system and, at this time, does not read from it. If tags are needed from the DGEN system, configuration will be required to allow the BOP system to read from it, or the DGEN system will have to push selected data arrays to the BOP system and then to the GE system as with the CTG systems. No cabling will be required for this, just software configuration in the DGEN and BOP systems.

The base of the communication connection point between the FLS system and the BOP A/B system will be Remote I/O cabinet 1, behind the newest air compressors, on the operating floor of the Power Plant. The existing ProSoft communications card (slot 10, model# MV156-MCMR) has two ports for MODBUS RTU communications via RJ45 jacks (and adapter cables for RS485), but they are both used. The FLS system will connect to the BOP system at the end of the least used MODBUS RTU run, in one of the new air compressors cabinets. These two air compressors are the only two devices on that run. This would not require another card (for MODBUS TCP, if required) to be installed and can be done while PNS is in operation. This connection scheme would require much less configuration and very little risk as opposed to setting up a new card. The FLS system connection point on the C90+ would be the RS485 port D on the power supply card on the rear of the device. The BOP Prosoft card is configured as a master (perfect since the C90+ only acts as a slave) and is presently configured for MODBUS RTU, the preferred MODBUS protocol of I and C Engineering and the BOP system. Programming assistance will be required from I and C Engineering for the above communications tasks.

7. Present settings of CTG#1 CGCM (Combined generator control module) as of 12/9/2014

It should be noted that the control system on CTG1 consists of a DECS 200 and PLC5 and on CTG2 a CGCM and ControlLogix PLC.

PROJECT CGCM PROTECTION FUNCTIONS CONFIGURATION REPORT

Basler Electric classified CGCM Protection Functions as follows:

The protective functions in the CGCM are time-proven and designed to provide a high degree of reliability, repeatability, longevity and accuracy. The CGCM is designed to meet or exceed applicable CE standards, but was not tested to all standards that many North American utilities use to define utility grade protection. However, the CGCM does possess many of the features that define utility grade protection.

The CGCM may be used as primary protection in applications not requiring utility grade protection or in utility applications where the authority having jurisdiction has approved the CGCM for use as primary protection. In applications requiring utility grade protection where the local authority has not evaluated or approved the CGCM, the CGCM may be used for secondary protection in conjunction with a primary protection system.



In Solar's standard design the CGCM protection functions are set to be used as secondary protection in conjunction with a primary protection system. When coordination conflicts arise between the standard CGCM protection function settings and zone protection schemes established by customers, the changes to the CGCM settings, proposed by the customer/vendor, resulting from a relay coordination study, need to be checked by systems engineering.

1.	Generator Overcurrent (51/51V)			
	Setpoint	175	% Rated I	
	Curve	9	ANSI C50.13	
	Voltage Restraint	100	% Rated V	
	Time Dial	4		
	Specification			
	Description	Range	Increment	Accuracy
	Pickup	10 320% of rated generator current	1%	+/- 2% of rated current
	Time delay	Characteristic Inverse per ANSI C50.13 configurable	0.1 s	
2.	Reverse Power Protection (32R)			
	Pickup	5	%	
	Time delay	10	s	
	Specification			
	Description	Range	Increment	Accuracy
	Pickup	1...100% of rated generator VA	1%	+/- 0.5% rated VA
	Time delay	0.10...300 s	0.10 s	+/- 0.1 s
3.	Loss of Field Protection (Reverse VAR 40Q)			
	Pickup	40	% Rate VA	
	Time delay	5	s	
	Specification			
	Description	Range	Increment	Accuracy
	Time Delay	0.10...300 s	0.10 s	+/- 0.1 s
4.	Loss of Field Protection (Loss of Excitation Current 40)			
	Pickup	0.28	A	
	Time Delay	0.2	s	
	Specification			
	Description	Range	Increment	Accuracy
	Pickup	0.1...15 A	0.1 A	
	Time Delay	0.1...9.9 s	0.1 s	

5.	Undervoltage Protection (27)			
	Pickup	85	%	
	Time Delay	10	s	
Specification				
	Description	Range	Increment	Accuracy
	Pickup	60...100% of rated generator voltage	1%	+/- 2% of rated voltage
	Time Delay	0.1...300 s	+/- 0.1 s	
6.	Overvoltage Protection (59)			
	Pickup	115	%	
	Time Delay	2	s	
Specification				
	Description	Range	Increment	Accuracy
	Pickup	100...140% of rated generator voltage	1%	+/- 2% of rated voltage
	Time Delay	0.1...300 s	+/- 0.1 s	
7.	Overfrequency Protection (81O)			
	Pickup	62.4	Hz	
	Time Delay	20	s	
Specification				
	Description	Range	Increment	Accuracy
	Pickup	30...70 Hz	0.01 Hz	+/- 2% Hz
	Time Delay	0.1...300 s	0.10 s	+/- 0.1 s
8.	Underfrequency Protection (81U)			
	Pickup	57.6	Hz	
	Time Delay	20	s	
Specification				
	Description	Range	Increment	Accuracy
	Pickup	30...70 Hz	0.01 Hz	+/- 2% Hz
	Time Delay	0.1...300 s	0.10 s	+/- 0.1 s
9.	Overexcitation Voltage (59F)			
	Pickup	105.6	VDC	
	Time Delay	10	s	
Specification				
	Description	Range	Increment	Accuracy
	Pickup	1...200 VDC	1 VDC	
	Time Delay	0.1...30 s	0.1 s	
10.	Loss of Sensing (60FL)			



The CGCM built-in Loss of Sensing protection is done internally in the module as follows:
 For three-wire and four-wire sensing, Loss of sensing detection is based on the logical combination of several conditions. The conditions include the following.

1. The average positive sequence voltage is greater than 8.8% of the AVR setpoint
2. The negative sequence voltage is greater than 25% of the positive sequence voltage
3. The negative sequence current is less than 17.7% of the positive sequence current
4. The positive sequence current is less than 1% of rated current for 0.1 s
5. The generator positive sequence voltage is less than 8.8% of the AVR setpoint
6. The positive sequence current is less than 200% of the rated current for 0.1 s

The three phase loss of sensing is expressed by the following logical formula.

Loss of Sensing = (1 and 2 and (3 or 4) or (5 and 6)

For single-phase sensing, Loss of sensing is detected when the following conditions exist in the proper logical combination.

1. The average generator terminal line-to-line voltage is less than 70% of the AVR setpoint
2. The positive sequence current is less than 200% of the rated current
3. The negative sequence current is less than or equal to 17.7% of the positive sequence current
4. The positive sequence current is less than 1% of rated current for 0.1 s

The single phase loss of sensing is expressed by the following logical formula.

Loss of Sensing = (1 and 2) and (3 or 4)

Specification

Description	Range
Pickup	See above
Time Delay	0.1 s for normal operation, 1 s during the soft start

11. Loss of Excitation Power (PMG) (27)

If voltage to the PMG power inputs falls below 10 VAC for 350msec., a Loss of Excitation Power fault occurs. When single phase PMG is selected, the CGCM senses phases A and C for this function.

Specification

Description	Range
Pickup	<10 VAC single-phase <50 VAC three-phase or Imbalance greater than 20%
Time delay	<400 ms

12. Phase Rotation Fault (47)

The CGCM calculates the negative sequence voltage of the three-phase generator voltage sensing input. When the generator phase rotation is opposite to the user-configured wiring rotation, the level of the generator negative sequence voltage increases to approximately 100%. The pickup value for this function is fixed at 66%. When the pickup value is exceeded, timing is started. A phase rotation fault is also indicated when a phase loss condition occurs.

Specification

Description	Range	Increment	Accuracy
Pickup	66% of rated voltage		+/- 2% of rated voltage



Time Delay		1 s	+/- 0.1 s	
13.	Rotating Diode Failure			
Open Diode Pickup		10	%	
Shorted Diode Pickup		30	%	
Time Delay		20	s	
Specification				
Description		Range	Increment	Accuracy
Open Diode Pickup			0...100% of ripple current	
Shorted Diode Pickup			0...100% of ripple current	
Time Delay			0.1...300 s	
Detection Inhibited			Field Current < 1.5VDC Generator Frequency < 45 Hz > 70 Hz	
14.	Sync-Check			
Frequency Match				
Lower Limit		-0.1	Hz	
Upper Limit		0.1	Hz	
Voltage Match				
Lower Limit		-1	%	
Upper Limit		1	%	
Phase Match				
Lower Limit		-10	deg	
Upper Limit		10	deg	
Acceptance Delay		0.5	sec	

8. CTG#1 Protective Relay Test Reports and Settings

AC Electric Corp.
Engineering Services
 Auburn, ME (207)-784-7341

Protective Relay Test Sheet

Customer Name: Ameresco Job Location: Portsmouth Naval
 Substation: Power Plant / 15kV Lineup Bay: Unit # 15
 Circuit I.D.: CTG#1 Generator Under / Over Voltage Protection
 Manufacturer and Type: Circuit Shield Voltage Relay (Type 27/59)
 Nameplate Data: 410D4470 Device: 27/59 Instruction Book: 7.4.1.7-1
 Neutral P/N: N/A Device: - Instruction Book: -
 Device Ratings: Tap Range 60-150VAC, 48/125VDC Contr
 Tested by: SEH Date: 10/7/14 AC Job #: _____

SETTINGS	27/59
59 Tap	140
59 Time Dial	2
59 Curve	Def. Med.
27 Tap	100
27 Time Dial	2
27 Curve	Def. Med.

Visual Inspection & Maintenance			
Cover: <u>OK</u>	Disc Gap: <u>N/A</u>	Glass ch'd: <u>OK</u>	Taps Tight: <u>OK</u>
Spral Spring: <u>N/A</u>	Moisture: <u>OK</u>	Relay ch'd: <u>OK</u>	Connect Tight: <u>OK</u>
Bearing: <u>N/A</u>	Foreign Mat: <u>OK</u>	Cont. ch'd: <u>N/A</u>	Insul Resist: <u>N/A</u>

Test Results					
A=Amp	s=Second	as found			as left (same as found unless noted)
		Specs.	27/59		
Over Voltage Pickup	140V				
Time Delay 0-154V Step	1.8-2.2s				
Time Delay 0-168V Step	1.8-2.2s				
Under Voltage Dropout	100V				
Time Delay 120-60V Step	1.8-2.2s				
Time Delay 120-0V Step	1.8-2.2s				
* Push to Test	Pass or Fail				
Targets / LEDs	Pass or Fail				

Notes: Aux. contacts verified – OK.
 Used +/- 10% for timing tolerance. No tolerance listed in I.B. for pickup – setting is continuously adjustable (max error above <0.4% – no changes made)
 Test results indicate that relay is suitable for service.



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Protective Relay

Test Sheet

Customer Name: Ameresco

Job Location: Portsmouth Naval

Substation: Power Plant / 15kV Lineup Bay: Unit # 16

Circuit I.D.: CTG#1 Generator Reverse Power Protection

Manufacturer and Type: Circuit Shield Reverse Power Relay (Type 32R)

Nameplate Data: 437P4571 Device: 32R Instruction Book: 7.8.1.7-1

Neutral P/N: N/A

Device: - Instruction Book: -

Device Ratings: Tap Range 0.1-0.7A, Curve = Def. 48/125VDC Contr.

Tested by: SEH Date: 10/7/14 AC Job #:

SETTINGS

Pickup

Time Dial

32R

0.1

3 (approx)

32R

0.1

3 (approx)

Cover: OK

Spiral Spring OK

Bearing OK

Disc Gap OK

Moisture OK

Foreign Mat OK

Glass ch'd OK

Relay ch'd OK

Cont. ch'd OK

Taps Tight OK

Connect. Tight OK

Insul Resist N/A

Visual Inspection & Maintenance

as found

as left

(same as found, unless noted)

A=Amp

s=Second

Operate Angle 1 & 2

Max Torque Angle

Min Pickup w/ 120V

Time Delay @ 0.5A

Time Delay @ 1.0A

No op for forward power

"Push to Test"

Targets / LED'S

Specs.

32R

-

-30 deg

0.1A

3.0s

3.0s

Pass or Fail

Pass or Fail

Pass or Fail

62, -122

-30 deg

0.11A

3.004s

3.013s

OK

OK

OK/OK

Test Results

Notes: Min pickup performed with I lag V by 30 deg.
 Equivalent secondary watts = V x I x 1.73 = 120 x 0.110 x 1.73 = 22.86W
 Test results indicate that relay is suitable for service.



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Protective Relay Test Sheet

Customer Name: Ameresco Job Location: PNSY
 Substation: Power Plant / 15kV Lineup Bay Unit # 16
 Circuit ID: CTG#1 Generator Loss of Field Protection
 Manufacturer and Type: Westinghouse Loss of Field Relay (KLF)
 Nameplate Data: 290B481A09 Device: 40 Instruction Book: 41-748
 Neutral P/N: N/A Device: - Instruction Book: -
 Device Ratings: 5A, 120V, 48/125VDC controls.
 Tested by: SEH Date: 10/7/14 AC Job #:

SETTINGS	40	found/left
SA	2	27.48 ohms
TA	15.8	1.10 ohms
MA	+0.15	ICS Tap
SC	1	0.2
TC	+1.27	
MC	+0.15	

Visual Inspection & Maintenance			
Cover: OK	Disc Gap N/A	Glass ch'd OK	Taps Tight OK
Spiral Spring N/A	Moisture OK	Relay ch'd OK	Connect Tight OK
Bearing N/A	Foreign Mat OK	Cont. ch'd OK	Insul Resist N/A

Test Results				
A=Amp	Specs.	as found	as left	(same as found, unless noted)
S=Second				
Min Pickup w/ 80V	1.88-2.00A	40		
Reach (ZA)	26.6-28.3 ohms	1.73A		
Min Pickup w/ 40V	23.43-24.88A	23.12 ohms		
Reach (ZC)	1.07-1.13 ohms	20.74A		
Dir Unit angles (1/2)	-	0.964 ohms		
MTA(I Lead V)	90 deg	83, 39		
Under Volt Unit Drop-Out	70-90V	91 deg		
ICS Pickup	< or = 0.2A	109V		
		0.21A		

Notes: Used formula from I.B for settings $Z = (T \times S) / (1+M)$ for ZA, $= (15.8 \times 2) / (1+0.15) = 27.48$ ohms. For testing $Z = V / (1.5 \times I)$ for ZA, $= 80 / (2 \times 1.73) = 23.12$
 Telephone relay check OK (MPU = 49.8VDC.) Insulating barrier in telephone relay was found loose – re-secured with silicone.
 UV dropout is higher than expected – assumed that this is an intentional setting due to multiple generators on common bus.
 Relay reach is off by about 9%. Recommend repair or replacement



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Protective Relay

Test Sheet

Customer Name: Ameresco

Job Location: Portsmouth Naval

Substation: Power Plant / 15kV Lineup Bay: Unit # 15

Circuit I.D.: CTG#1 Neutral Overcurrent Protection

Manufacturer and Type: Basler BE1-50/51B-105 Overcurrent Relay

Nameplate Data: N/A

Device: 51N

Instruction Book: 9252000991

Neutral P/N: N/A

Device: -

Device Ratings: 0-99A, switch selectable curves

Tested by: SEH

Date: 10/7/14

AC Job #:

SETTINGS

Pickup

Time Dial

Instantaneous

Curve

51N

2.5

3.0

99

I = Inverse

Cover: OK

Spiral Spring N/A

Bearing N/A

Disc Gap N/A

Moisture OK

Foreign Mat OK

Glass ch'd

Relay ch'd

Cont. ch'd

OK

OK

N/A

Taps Tight

Connect. Tight

Insul Resist

N/A

N/A

N/A

Visual Inspection & Maintenance

as found

as left

(same as found, unless noted)

A=Amp	Specs.	51N			
s=Second					
Min Pickup	2.43-2.58A	2.51A			
Time @ 2X	8.43-8.77s	8.751s			
Time @ 5X	1.47-1.53s	1.519s			
Instantaneous	99A	* Not Tested			
Aux Contacts(4-5)	Pass or Fail	OK			
Targets/LED's	Pass or Fail	OK / OK			

Notes: *Instantaneous contacts not wire out from case – function not used.
Used +/- 2% +/- 0.025A for MPU & +/- 2% for timing tolerances
Test results indicate that relay is suitable for service.



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Protective Relay

Test Sheet

Customer Name: Ameresco

Job Location: Portsmouth Naval Substation: Power Plant / 15kV Lineup Bay: Unit # 15

Circuit I.D.: CTG#1 Phase Overcurrent Protection

Manufacturer and Type: Westinghouse Volt. Contr. Over-Current Relay (COV-8)

Nameplate Data: 1878517 Device: 51V Instruction Book: 41-116

Neutral P/N: N/A Device: - Instruction Book: -

Device Ratings: Tap Range 2-6A; 120VAC Contr. Inst 10-40A

Tested by: SEH Date: 10/7/14 AC Job #:

SETTINGS

Pickup Tap	A	B	C
Time Dial	2	2	2
Instantaneous	6	6	6
ICS Tap	30+	30	30
	0.2	0.2	0.2

Cover: OK

Spiral Spring OK

Bearing OK

Disc Gap OK

Moisture OK

Foreign Mat OK

Glass ch'd OK

Relay ch'd OK

Cont. ch'd OK

Taps Tight OK

Connect Tight OK

Insul Resist N/A

Visual Inspection & Maintenance

Test Results

A=Amp	as found				as left	(same as found, unless noted)
s=Second	Specs.	A	B	C		
Min Pickup	1.94-2.06A	1.98A	1.99A	1.99A		
Time @ 3X	5.04-5.57s	5.483s	5.524s	5.503s		
Time @ 5X	2.38-2.63s	2.425s	2.474s	2.458s		
Instantaneous	10-40A	36A	31A	32A		
Volt Unit Drop Out	80-100V	97.1V	95.7V	95.4V		
ICS Pickup	< or = 0.2A	0.18A	0.19A	0.21A		
Target & Seal-In	Pass or Fail	OK/OK	OK/OK	OK/OK		

Notes: Relay found in "A" case was marked 51V-B on relay cradle & in "B" case relay was marked 51V-A – left relays in as found positions.
Used +/- 3% for MPU & +/- 5% for timing tolerances.
"A" phase instantaneous is higher than other phases (+20%) – recommend review of coordination study to verify acceptability of results.
Test results indicate that relay is suitable for service.



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Protective Relay

Test Sheet

Customer Name: Ameresco

Job Location: Portsmouth Naval

Substation: Power Plant / 15kV Lineup Bay: Unit # 15 TEG 3119

Circuit I.D.: CTG#1 Generator VT Failure Protection

Manufacturer and Type: GE Voltage Balance Relay

Nameplate Data: 12CFVB11B5A Device: 60 Instruction Book: GEK-41831

Neutral P/N: N/A Device: - Instruction Book: -

Device Ratings: 120V, 48 / 125 VDC

Tested by: SEH

Date: 10/7/14

AC Job #:

SETTINGS

60

Cont'r Volts

Link out = 125

Cont'r Volts

Link out = 125

Cover: OK

Spiral Spring: N/A

Bearing: N/A

Disc Gap: N/A

Moisture: OK

Foreign Mat: OK

Glass ch'd: OK

Relay ch'd: OK

Cont. ch'd: OK

Taps Tight: OK

Connect. Tight: OK

Insul Resist: N/A

Visual Inspection & Maintenance

as found

as left (same as found, unless noted)

A=Amp

s=Second

Balance @ 0V

Balance @ 120V

Dropout @ 120V*

Pickup @ 0V*

Targets

Specs.

60

Pass or Fail

Pass or Fail

96V

72V

Pass/Fail

OK

OK

88.7V

75.2V

OK

Test Results

Test results indicate that relay is suitable for service.



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Protective Relay

Test Sheet

Customer Name: Ameresco

Job Location: Portsmouth Naval

Substation: Power Plant / 15kV Lineup Bay: Unit # 15

Circuit I.D.: CTG#1 Generator Under Frequency Protection

Manufacturer and Type: GE Frequency Relay

Nameplate Data: 12SFF32A1A Device: 81U Instruction Book: GEK-49923

Neutral P/N: N/A

Device: - Instruction Book: -

Device Ratings: 120V RMS, 44-61Hz

Tested by: SEH Date: 10/7/14 AC Job #: 442150

SETTINGS

#1 Setting

512+256+64+8 = 840

= 56.005 Hz

#2 Setting

1024+256+128+32+16 = 1456

=56.004 Hz

#1 ICS Tap

0.2

#2 ICS Tap

0.2

81

512+256+64+8 = 840

= 56.005 Hz

1024+256+128+32+16 = 1456

=56.004 Hz

0.2

0.2

Cover: OK

Spiral Spring: N/A

Bearing: N/A

Disc Gap: N/A

Moisture: OK

Foreign Mat: OK

Glass ch'd: OK

Relay ch'd: OK

Cont. ch'd: OK

Taps Tight: OK

Connect. Tight: OK

Insul Resist: N/A

Visual Inspection & Maintenance

as found

as left

(same as found, unless noted)

A=Amp

s=Second

#1 Min Pickup

Time 60-57.5 Hz

Time 60-57.0 Hz

ICS Pickup #1

Specs.

58.00Hz

Inst.

Inst.

< or = 0.2A

81

58.00Hz

0.417s

0.407s

0.18A

Notes: Setpoints = 1,000,000/(16,400+sum of switches)

UV inhibit verified by applying 57.0Hz and decreasing voltage until reset: 44.7VAC.

No wiring connected to terminals 13-14; #2 setting trip output not used, not tested.

Test results indicate that relay is suitable for service.



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Protective Relay Test Sheet

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Notes: Instantaneous contacts not wire out from case – function not used.
Used +/- 2% +/- 0.025A for MPU & +/- 2% for timing tolerances
Test results indicate that relay is suitable for service.



Protective Relay Test Sheet

Customer Name: Ameresco Job Location: PNSY
Substation: Power Plant / 15kV Lineup Bay: Unit # 10
Circuit I.D.: CTG#2 Current Differential Protection
Manufacturer and Type: Basler Generator Differential (BE1.87G)
Nameplate Data: G1EA1JA0N0F Device: 87G Instruction Book: 9170800990
Neutral P/N: N/A Device: - Instruction Book: -
Device Ratings: 0.1-1.6A, Curve = Inst.
Tested by: NJW Date: 10/10/12 AC Job #: 442150

SETTINGS	87G			
MPU Tap	D = 0.4			
Ser No.	H00330319RU			

Visual Inspection & Maintenance				
Cover:	OK	Disc Gap	N/A	
Spiral Spring	N/A	Moisture	OK	Glass cl'd'd N/A
Bearing	N/A	Foreign Mat	OK	Relay cl'd'd N/A
				Cont. cl'd'd N/A
				Taps Tight N/A
				Connect. Tight OK
				Insul. Resist N/A

Test Results							
A=Amp	as found						
s=Second	Specs.	A	B	C		as left	(Same as found unless noted)
Wdg 1 MPU	0.38-0.42A	0.42A	0.42A	0.42A			
Wdg 2 MPU	0.38-0.42A	0.42A	0.42A	0.42A			
Slope w/6A restraint	0.73 – 0.79A	0.77A	0.77A	0.77A			
Slope w/9A restraint	2.20 – 2.40A	2.26A	2.31A	2.29A			
Targets	Pass/Fail	OK	OK	OK			

Notes:
Test results indicate that relay is suitable for service.



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Multi-Function Relay Test Report

Customer: Ameresco	Model: GPS100	Test Date: 10/10/2012
Substation: Power Plant	Serial Number: H00331162	Tested By: NJW
Circuit ID: CTG #2	Software Version: BESCOMS	Page: 1 of 3
Relay Manufacturer: Basler	Settings: See Attached	Password: ACCESS=

Function	Expected Results	As Found Results			Notes
		A/A-B	B/B-C	C/C-A	
27 Pickup	96.0V	95.9V	95.9V	96.0V	Disable fuse loss SP-60FL=DIS,DIS
27 Time Delay:					
120-90V Step	2.50s	2.52s	2.52s	2.52s	
120-0V Step	2.50s	2.52s	2.50s	2.50s	
32 MTA Angles 120V, 0.5A	-	228.1, 67.7	3PH	3PH	
32 MTA Calculated	150°	147.9°	3PH	3PH	
32 MPU@120V (Amps)	0.087A	0.088A	3PH	3PH	
32 MPU (Watts)	18.0W	18.3W	3PH	3PH	W=I*V**1.73
32 Time Delay:					
0-27W Step (0-0.13A)	3.00s	3.02s	3PH	3PH	
0-36W Step (0-0.30A)	3.00s	3.02s	3PH	3PH	
40Q MTA Angles 120V, 4.0A	-	119.4, -14.3	3PH	3PH	
40Q MTA Calculated	60°	52.6°	3PH	3PH	
40Q Pickup w/120V	325VARs = 1.56A	1.58A	3PH	3PH	
40Q Time Delay:					
0-487.5VAR Step (2.35A)	0.50s	0.51s			
0-650VAR Step (3.13A)	0.50s	0.52s	3PH	3PH	
46 Pickup	0.50A	0.51A	3PH	3PH	
46 Time Delay:					
0-5A Step	40.0s	39.95s	3PH	3PH	
0-10A Step	10.0s	10.04s			
No Trip Positive Sequence	Pass/Fail	OK	3PH	3PH	



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Multi-Function Relay Test Report

Customer: Ameresco		Page: 2	
Circuit ID: CTG #2		Date: 10/10/2012	
51V Pickup @ 0V	1.80A	1.79A	1.80A
51V Time Delay:			
0-3.6A Step	4.20s	4.18s	4.18s
0-9.0A Step	2.30s	2.33s	2.34s
Dropout Voltage	96.0V	95.9V	-
59 Pickup	132.0V	132.0V	132.0V
59 Time Delay			
120-133V Step	1.50s	1.53s	1.54s
120-140V Step	1.50s	1.52s	1.52s
81-O Pickup	62.00Hz	62.00Hz	3PH
81-O Time Delay			
60-62.5Hz Step	2.50s	2.52s	3PH
60-64Hz Step	2.50s	2.52s	3PH
Under Voltage Cutoff @ 63Hz	40.0V	39.9V	3PH
81-U Pickup	58.00Hz	58.00Hz	3PH
81-U Time Delay			
60-57Hz Step	2.50s	2.53s	3PH
60-55Hz Step	2.50s	2.53s	3PH
Under Voltage Cutoff @ 55Hz	40.0V	40.0V	3PH



10. Woodward 2301A Instruction Manual



Product Manual 82386
(Revision B)
Original Instructions

2301A Electronic Load Sharing and Speed Control with Temperature Limiting or Process Limiting

Installation and Operation Manual





**General
Precautions**

Read this entire manual and all other publications pertaining to the work to be performed before installing, operating, or servicing this equipment.

Practice all plant and safety instructions and precautions.

Failure to follow instructions can cause personal injury and/or property damage.



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Warnings and Notices

Important Definitions



This is the safety alert symbol. It is used to alert you to potential personal injury hazards. Obey all safety messages that follow this symbol to avoid possible injury or death.

- **DANGER**—Indicates a hazardous situation which, if not avoided, will result in death or serious injury.
- **WARNING**—Indicates a hazardous situation which, if not avoided, could result in death or serious injury.
- **CAUTION**—Indicates a hazardous situation which, if not avoided, could result in minor or moderate injury.
- **NOTICE**—Indicates a hazard that could result in property damage only (including damage to the control).
- **IMPORTANT**—Designates an operating tip or maintenance suggestion.

WARNING

Overspeed / Overtemperature / Overpressure

The engine, turbine, or other type of prime mover should be equipped with an overspeed shutdown device to protect against runaway or damage to the prime mover with possible personal injury, loss of life, or property damage.

The overspeed shutdown device must be totally independent of the prime mover control system. An overtemperature or overpressure shutdown device may also be needed for safety, as appropriate.

WARNING

Personal Protective Equipment

The products described in this publication may present risks that could lead to personal injury, loss of life, or property damage. Always wear the appropriate personal protective equipment (PPE) for the job at hand. Equipment that should be considered includes but is not limited to:

- Eye Protection
- Hearing Protection
- Hard Hat
- Gloves
- Safety Boots
- Respirator

Always read the proper Material Safety Data Sheet (MSDS) for any working fluid(s) and comply with recommended safety equipment.

WARNING

Start-up

Be prepared to make an emergency shutdown when starting the engine, turbine, or other type of prime mover, to protect against runaway or overspeed with possible personal injury, loss of life, or property damage.

WARNING

Automotive Applications

On- and off-highway Mobile Applications: Unless Woodward's control functions as the supervisory control, customer should install a system totally independent of the prime mover control system that monitors for supervisory control of engine (and takes appropriate action if supervisory control is lost) to protect against loss of engine control with possible personal injury, loss of life, or property damage.

NOTICE

Battery Charging Device

To prevent damage to a control system that uses an alternator or battery-charging device, make sure the charging device is turned off before disconnecting the battery from the system.

Electrostatic Discharge Awareness

NOTICE

Electrostatic Precautions

Electronic controls contain static-sensitive parts. Observe the following precautions to prevent damage to these parts:

- Discharge body static before handling the control (with power to the control turned off, contact a grounded surface and maintain contact while handling the control).
- Avoid all plastic, vinyl, and Styrofoam (except antistatic versions) around printed circuit boards.
- Do not touch the components or conductors on a printed circuit board with your hands or with conductive devices.

To prevent damage to electronic components caused by improper handling, read and observe the precautions in Woodward manual **82715**, *Guide for Handling and Protection of Electronic Controls, Printed Circuit Boards, and Modules*.

Follow these precautions when working with or near the control.

1. Avoid the build-up of static electricity on your body by not wearing clothing made of synthetic materials. Wear cotton or cotton-blend materials as much as possible because these do not store static electric charges as much as synthetics.
2. Do not remove the printed circuit board (PCB) from the control cabinet unless absolutely necessary. If you must remove the PCB from the control cabinet, follow these precautions:
 - Do not touch any part of the PCB except the edges.
 - Do not touch the electrical conductors, the connectors, or the components with conductive devices or with your hands.
 - When replacing a PCB, keep the new PCB in the plastic antistatic protective bag it comes in until you are ready to install it. Immediately after removing the old PCB from the control cabinet, place it in the antistatic protective bag.

Available Models

These 2301A electronic controls with temperature limiting or process limiting are available in the following models. Speed range is selected by a switch.

Table 1-1. 2301A LSSC w/ Temperature or Process Limiting

Part Number	High/Low Voltage	Actuator Current (mA)				Forward/Reverse Acting	Terminals 31 & 32	Actuator Tandem/Single
		4-20	0-50	0-200	0-400			
8272-608	Low			X		Forward	mA / Vdc	Single
8272-609	High			X		Forward	Thermocouple	Single
8272-610	High			X		Forward	mA / Vdc	Single
8272-611	Low			X		Forward	Thermocouple	Single



Chapter 1. General Information

Description

The 2301A controls load sharing and speed of generators driven by diesel or gasoline engines, or steam or gas turbines. These power sources are referred to as "prime- movers" throughout this manual.

The control is housed in a sheet-metal chassis and consists of a single printed circuit board. All potentiometers are accessible from the front of the chassis.

The 2301 A provides control in either isochronous or droop mode.

The isochronous mode is used for constant prime mover speed with:

- Single-prime-mover operation or
- Two or more prime movers controlled by Woodward load sharing control systems on an isolated bus.
- Base loading against an infinite bus with the load controlled by an Automatic Power Transfer and Load (APTL) Control, an Import/Export Control, a Generator Loading Control, a Process Control, or another load-controlling accessory.

The droop mode is used for speed control as a function of load with:

- Single-prime-mover operation on an infinite bus or
- Parallel operation of two or more prime movers.

The 2301 A system for a single prime-mover generator includes:

- A 2301A electronic control,
- An external 20 to 45 V dc power source (low voltage model), or an external 90 to 150 Vdc or 88 to 132 Vac power source (high voltage model),
- A speed-sensing device,
- A proportional actuator to position the fuel- or steam-metering device, and
- Current and potential transformers for measuring the load carried by the generator.

This control is available in two models. In addition to speed and load sharing control, one model provides temperature limiting (using a type K thermocouple), and the other model provides process limiting (4 to 20 mA or 1 to 5 Vdc inputs).

The temperature limiting or process limiting section has its own gain and reset adjustments and is enabled or disabled by a switch contact input to the 2301A control.

A light emitting diode (LED) on the front of the 2301A control indicates when the temperature or process limiting is in control of the prime mover.

Applications

The 2301A with temperature limiting is primarily intended to limit the exhaust gas temperature on small gas turbines or reciprocating engines.



2301A LSSC w/Temperature or Process Limiting**Manual 82386**

The 2301A with process limiting can be used to limit processes such as the exhaust pressure of a steam turbine or the export power of a generator set. It can also be used in the same applications as the temp control if a temperature transducer is used to provide a 1 to 5 Vdc or 4 to 20 mAdc input signal.

The 2301A load sharing and speed controls with temperature or process limiting have switch-selectable speed ranges. All models of these controls can be set to operate within one of the following speed ranges:

- 500 to 1500 Hz
- 1000 to 3000 Hz
- 2000 to 6000 Hz
- 4000 to 12 000 Hz

These controls are available for use with single, forward-acting actuators. Actuator current is 0–200 mA. These controls accept either of two operating voltages. One type accepts 90 to 150 Vdc or 88 to 132 Vac, 45 to 440 Hz (identified as “HV” on the front of the control) and one type accepts 20 to 45 Vdc power (low voltage model, identified as “LV” on the front of the control). Table 1-1 shows part numbers and features of all 2301A load sharing and speed controls with temperature or process limiting.

The relationship between prime mover speed and sensor output frequency is expressed in the formula:

Sensor Frequency in Hz equals the number of teeth on the speed sensing gear times the rated prime mover speed in revolutions per minute divided by 60.

Application engineers from Woodward or any of its authorized distributors or agents are always available to assist you in selection of the correct control for your system, or to answer questions concerning control installation, operation, or calibration. See Chapter 6 for contact information.

References

The following publications contain additional product or installation information on Load Sharing and Speed Controls, and related components. They are available on the Woodward website (www.woodward.com/ic).

**technical
manual**
title

25070	<i>Electric Governor Installation Guide</i>
25195	<i>Governing Fundamentals</i>
82384	<i>SPM-A Synchronizer 9905-002</i>
82510	<i>Magnetic Pickups & Proximity Switches for Electronic Controls</i>
82715	<i>Guide for Handling and Protection of Electronic Controls, Printed Circuit Boards, and Modules</i>

product**specification title**

82383	<i>SPM-A Synchronizer</i>
82387	<i>2301A LS and SC with Temp Limiting or Process Limiting</i>
82516	<i>EG3P/6P/10P Actuator</i>
82575	<i>EGB1P/2P Governor/Actuator</i>



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2301A LSSC w/Temperature or Process Limiting

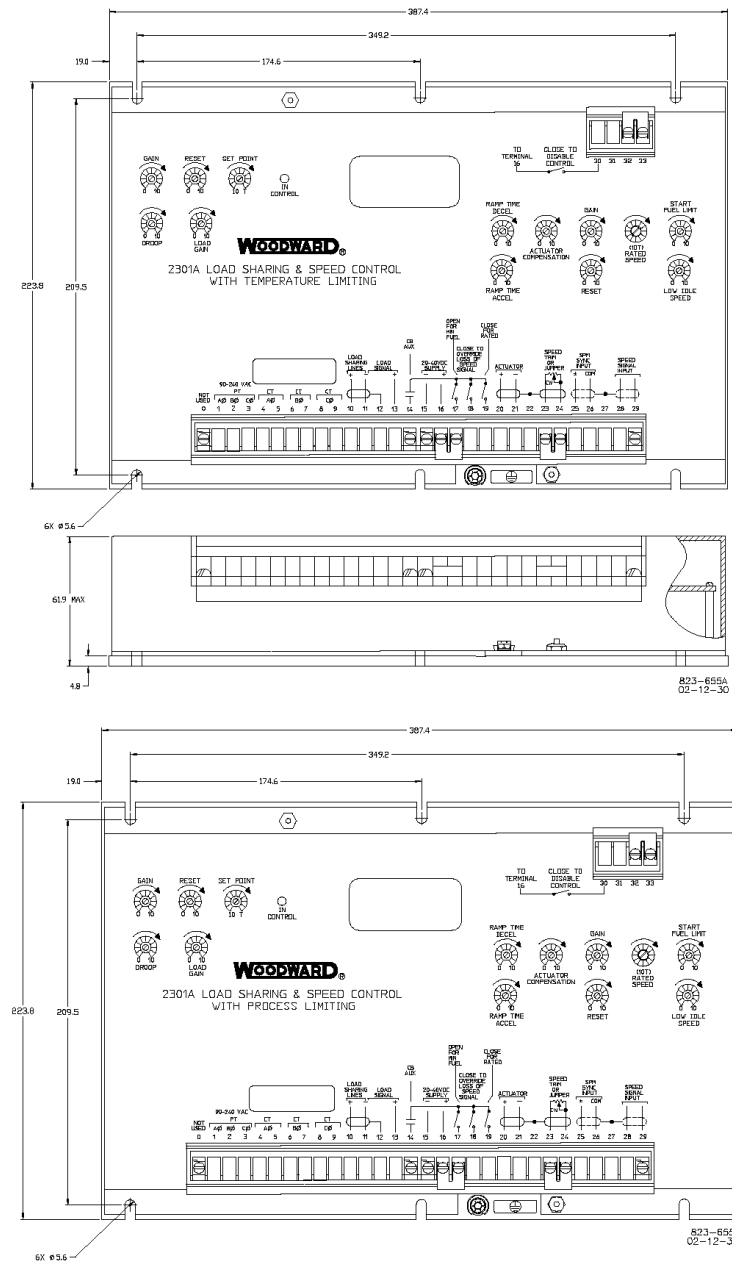


Figure 1-1. 2301A Load Sharing and Speed Control
 (low voltage version shown; temperature limiting above; process limiting below)

2301A LSSC w/Temperature or Process Limiting

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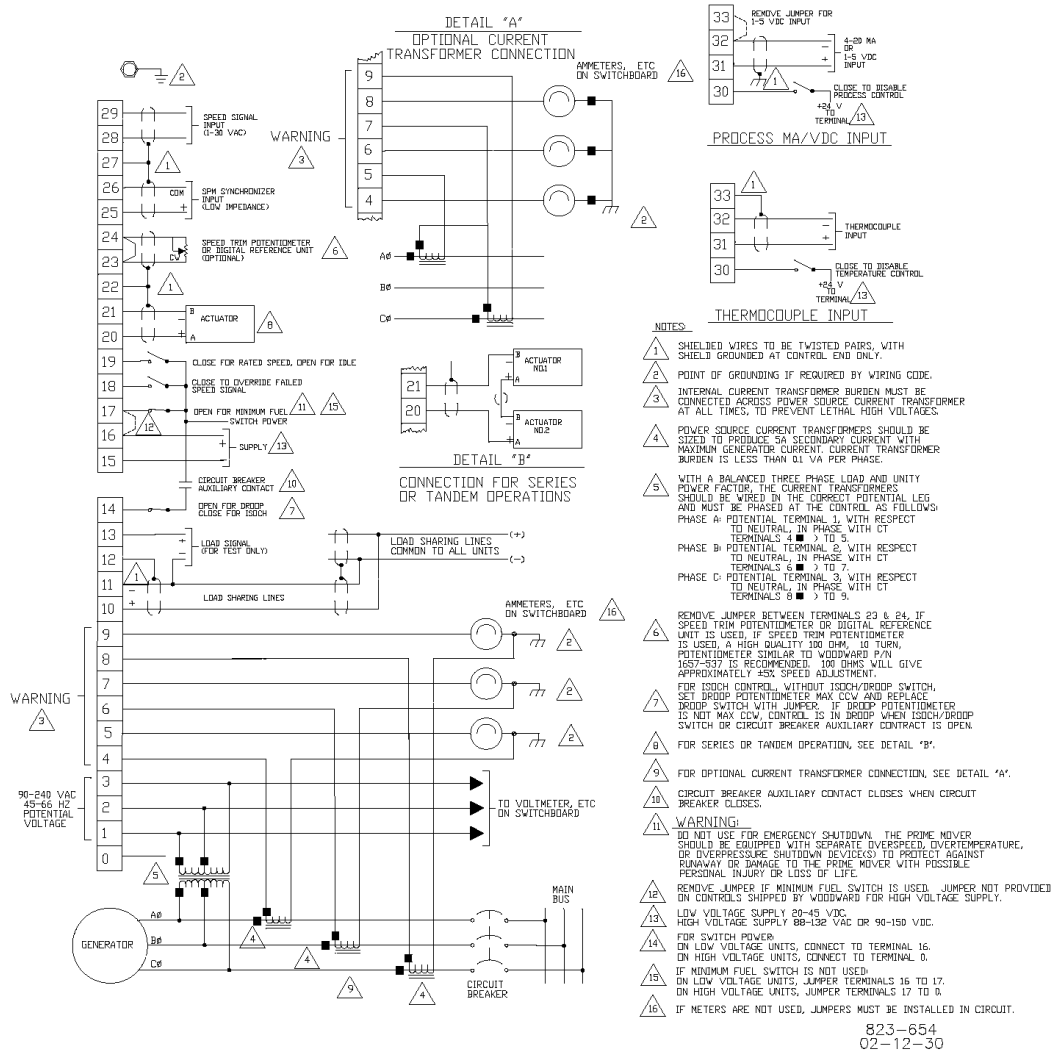


Figure 1-2. Plant Wiring Diagram

Chapter 2. Installation

Unpacking

Before handling the control, read the "Electrostatic Discharge Awareness" precautions on page iii. Be careful when unpacking the electronic control. Check the control for signs of damage such as bent or dented panels, scratches, and loose or broken parts. If any damage is found, immediately notify the shipper.

Power Requirements

The 2301 A control requires a voltage source of 20 to 45 Vdc, 90 to 150 Vdc, or 88 to 132 Vac for operating power. If a battery is used for operating power, an alternator or other battery charging device is necessary to maintain a stable supply voltage.

NOTICE

To prevent damage to the control, make sure that the alternator or other battery-charging device is turned off or disconnected before disconnecting the battery from the control.

Location Considerations

Consider these requirements when selecting the mounting location:

- Adequate ventilation for cooling
- Space for servicing and repair
- Protection from direct exposure to water or to a condensation-prone environment
- Protection from high-voltage or high-current devices, or devices which produce electromagnetic interference
- Avoidance of vibration
- Selection of a location that will provide an operating temperature range of -40 to $+70$ °C (-40 to $+158$ °F)
- The control must NOT be mounted on the engine.

Electrical Connections

External wiring connections and shielding requirements for a typical control installation are shown in the plant wiring diagram (Figure 1-2). These wiring connections and shielding requirements are explained in the balance of this section.



Shielded Wiring

All shielded cable must be twisted conductor pairs. Do not attempt to tin the braided shield. All signal lines should be shielded to prevent picking up stray signals from adjacent equipment. Connect the shields to the control terminals as shown in Figure 2-1, and the plant wiring diagram (Figure 1-2). Wire exposed beyond the shield should be as short as possible, not exceeding two inches. The other end of the shields must be left open and insulated from any other conductor. Do not run shielded signal wires with other wires carrying large currents. See manual 50532, *EMI Control for Electronic Governing Systems*, for more information.

Where shielded cable is required, cut the cable to the desired length and prepare the cable as shown in Figure 2-1.

1. Strip outer insulation from BOTH ENDS, exposing the braided or spiral wrapped shield. DO NOT CUT THE SHIELD.
2. Using a sharp, pointed tool, carefully spread the strands of the shield.
3. Pull inner conductor(s) out of the shield. If shield is the braided type, twist to prevent fraying.
4. Remove 6 mm (1/4 inch) of insulation from the inner conductor(s).
5. Connect wiring and shield as shown.

In installations with severe electromagnetic interference (EMI), shielded wire run in conduit, double shielded wire, or other precautions may be required. Contact Woodward for more information.

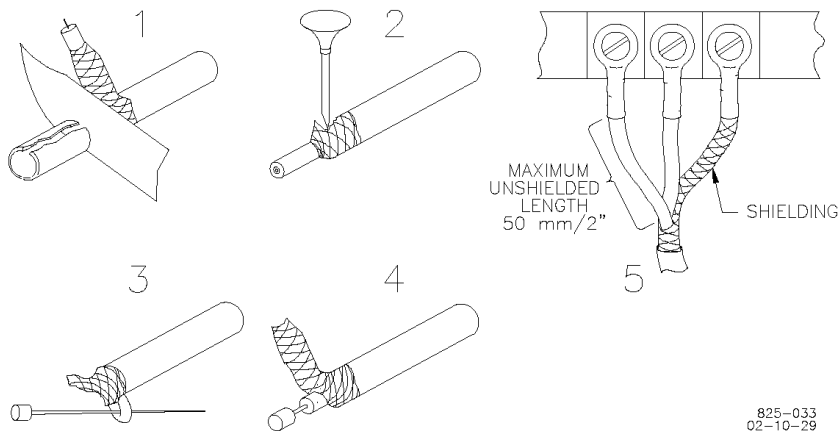


Figure 2-1. Preparation and Installation of Shielded Cables

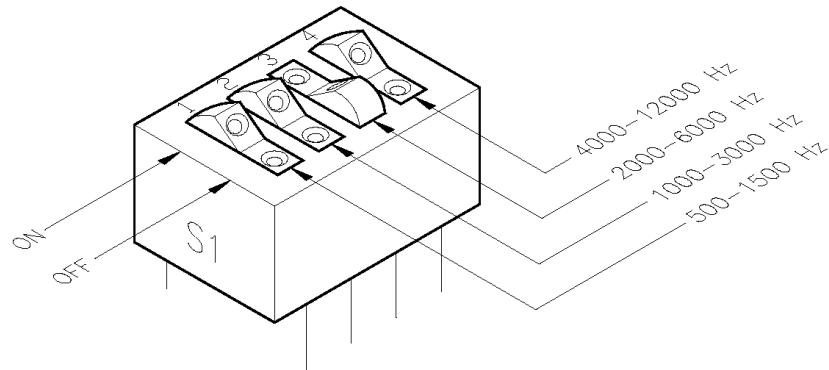
Setting Speed Range

The speed range to be selected is determined by the maximum desired prime mover speed. Calculate the frequency of the speed sensor signal at the maximum prime mover speed by multiplying the speed in revolutions per minute times the number of teeth on the speed sensing gear and dividing by 60. Select the lowest speed range which contains this maximum speed sensor frequency.

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2301A LSSC w/Temperature or Process Limiting

Figure 2-2 shows the four sections of Switch S1 and their corresponding speed ranges. Set the proper section of Switch S1 to the ON position and the other three positions of Switch S1 to the OFF position.



SWITCH S1

82300-A-176
90-07-30 MOL

Figure 2-2. Switch S1

Potential Transformer Connections

Connect the potential transformer secondary leads to the following terminals:

- Phase A to terminal 1
- Phase B to terminal 2
- Phase C to terminal 3

The potential transformer secondary line-to-line voltage must be in the 90 to 240 volt RMS range. Refer to the plant wiring diagram (Figure 1-2).

Current Transformer Connections

The standard method of connecting the current transformers is shown in the plant wiring diagram (Figure 1-2). An alternate method is the open delta connection shown in the insert in the plant wiring diagram.

Droop Contact (Isoch-Droop) and Load Sharing Lines

Because the load-sharing-line relay is contained in the control, no relay is required between the control and the load-sharing-line bus. Use shielded cable and connect the load-sharing lines directly to terminals 10 (+) and 11 (-). Connect the shield to terminal 12. When all controls in the system are of the 2301A type, the shields may be connected continuously between controls. When load sharing with different controls, do not connect the shields at the point where connections are made to the load-sharing-line bus.

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The droop contact for selecting droop or isochronous operation is wired in series with the circuit-breaker auxiliary contact between terminal 14 and terminal 16 (terminal 0 on high-voltage controls). When both the droop contact and circuit-breaker auxiliary contact are closed, the control is in the isochronous load-sharing mode (Figure 2-3, A). In this mode the internal load-sharing-line relay is energized, the droop signal is disabled permitting isochronous load sharing, and the load-matching circuit is connected to the load-sharing lines.

The control is in the droop mode when EITHER the droop contact or the circuit-breaker auxiliary contact is open (Figure 2-3, B). If the droop contact is open, the control remains in the droop mode even when the circuit-breaker auxiliary contact is closed.

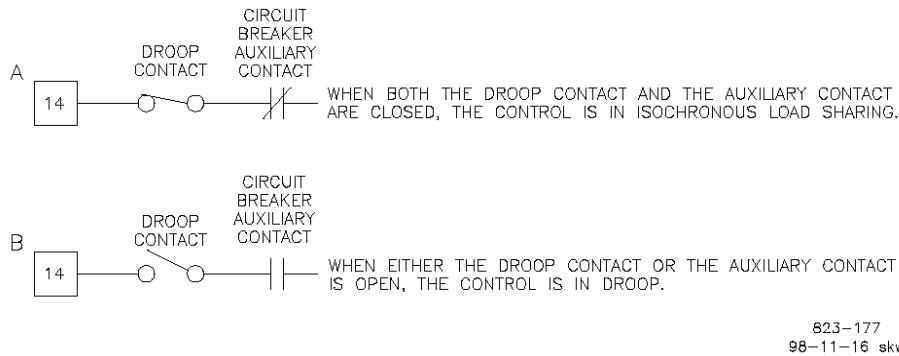


Figure 2-3. Droop Contact and Circuit Breaker Auxiliary Contact

IMPORTANT

The control is in the droop mode whenever the circuit-breaker auxiliary contact is open. If a single prime mover is required to run isochronously with an isolated load, turn the **DROOP** potentiometer fully counterclockwise.

Droop operation is required when the generator is paralleled with an infinite bus without a Generator Load inn Control, Process Control, Automatic Power Transfer and Load Control or other load controlling accessory, Import/Export Control, or when paralleled with incompatible governors. (All Woodward electric load-sharing systems are compatible.) When running a single unit on an infinite bus with a Generator Loading Control or Import/Export Control, terminal 14 must be connected to terminal 16 (terminal 0 on high-voltage controls) to connect the Load Matching Circuit to the load-sharing lines. The load-sharing lines must be wired to the Generator Loading Control or Import/Export Control. The circuit-breaker auxiliary contact will then be connected to the Generator Loading Control or Import/Export Control and not to the 2301A Load Sharing And Speed Control.

Power Supply

Run the power leads directly from the power source to the control, connecting the negative lead to terminal 15, and the positive lead to terminal 16. If the power source is a battery, be sure the system includes an alternator or other battery-charging device.

NOTICE

DO NOT apply power to the control at this time. Applying power before a control is completely connected may damage the control.

Minimum Fuel Contact

The minimum-fuel contact is intended as an optional means for a normal shutdown of the prime mover. It is connected in series with terminal 16 (terminal 0 on high-voltage controls) and terminal 17 as shown in the plant wiring diagram (Figure 1-2). Do NOT remove this jumper from terminal 17 unless a minimum fuel contact is installed; the control will not operate without 20 to 45 V dc applied to terminal 17.

When the contact is closed, the voltage applied to terminal 17 allows the control to move the actuator to any position required for operating conditions.



WARNING

Do NOT use the minimum-fuel contact as part of any emergency stop sequence.

Failed Speed Signal Override

A contact to override the failed-speed-signal circuit can be installed in series with terminal 18 and the dc power to the control. When the contact is open, the control operates normally, turning the control output off in the event of a loss of speed signal. Closing the contact overrides the failed-speed-signal circuit as may be required for start-up.

Prior to start-up of the prime mover, the speed signal is nonexistent. On prime movers with cranking motors, the cranking speed is usually sufficient to provide a speed signal, so an override contact on terminal 18 is not needed for starting. On some steam turbine systems, the Close to Override Failed Speed Signal contact must be closed in order to allow the actuator to open and provide steam for starting.

If a failed-speed-signal-override contact is used, it should be of the momentary type to ensure that the failed-speed-sensor shut-down circuit is enabled after start-up.

Idle/Rated Ramp Contact

Connect a single-pole, single-throw contact from terminal 16 (terminal 0 on high-voltage controls) to terminal 19, the Close For Rated (open for idle, close for rated) terminal. Oil pressure is often used to close this contact. When closed, 20 to 45 V dc is applied to terminal 19, and the prime mover can be operated at a speed higher than idle. When the contact is open, the voltage is removed from terminal 19, and the prime mover's speed immediately decelerates to idle.

Actuator Output

The actuator wires connect to terminals 20 (+) and 21 (–). Use shielded wires with the shield connected to terminal 22. Do not connect the shield to the actuator or any other point. The shield must have continuity the entire distance to the actuator, and must be insulated from all other conducting surfaces. Refer to the manuals listed in Chapter 1, References, table for additional information on actuator installation.

External Speed Trim

A jumper must be connected to terminals 23 and 24 unless an optional remote Speed Trim potentiometer is used. If a Speed Trim potentiometer is used, connect it as shown in the plant wiring diagram (Figure 1-2), using shielded wire. Connect the shield to terminal 22. Make sure the shield has continuity the entire distance to the potentiometer, and that the shield is insulated from all other conducting surfaces. A 100 Ω potentiometer will provide $\pm 5\%$ speed adjustment. If less adjustment is desired, potentiometers of smaller values may be used. Potentiometers of the multi-turn type are recommended.

Speed And Phase Matching (SPM) Synchronizer

Connect the SPM Synchronizer (optional equipment) wires to terminals 25 (+) and 26 (–). Use shielded wire, and connect the shield to terminal 27. Make sure the shield has continuity the entire distance to the SPM Synchronizer, but do not connect the shield to the synchronizer. The shield must be insulated from all other conducting surfaces.

Speed Sensor

Connect a speed-sensing device, such as a magnetic pickup, to terminals 28 and 29 using shielded wire. Connect the shield to terminal 27, making sure the shield has continuity the entire distance to the speed sensor, and that the shield is insulated from all other conducting surfaces.

Temperature Limiter Connections

Connect a type K thermocouple to terminals 31, 32, and 33, using twisted-pair, shielded thermocouple wire. Connect the shield to terminal 33, making sure the shield has continuity the entire distance from the thermocouple to the control. The shield must be insulated from all other conducting surfaces.

Connect the Temperature Control Disable switch between terminal 30, and terminal 0 (high-voltage models) or 16 (low-voltage models).



Process Limiter Connections

4 to 20 mA

Connect the 4 to 20 mA device wires to terminals 31 (+) and 32 (-). Install a jumper between terminals 32 and 33.

1 to 5 Vdc

Connect the 1 to 5 Vdc device wires to terminals 31 (+) and 32 (-). Make sure there is no jumper installed between terminals 32 and 33.

Installation Check-Out Procedure

With the installation completed as described in this chapter, do the following check-out procedure before beginning the start-up adjustments in Chapter 3.

1. Visual Inspection

- A. Check the linkage between the actuator and the prime mover for looseness or binding. Refer to the appropriate actuator manual and to Manual 25070, *Electric Governor Installation Guide*, for additional information on linkage.



WARNING

The actuator lever should be near but not at the minimum position when the fuel or steam rack is at the minimum position. If the actuator lever gets to its minimum position before completely shutting off fuel or steam, the control may not be able to shut the turbine down, causing damage to equipment or injury or death.

- B. Check for correct wiring per the plant wiring diagram (Figure 1-2).
- C. Check for broken terminals and loose terminal screws.
- D. Check the speed sensor for visible damage. If the sensor is a magnetic pickup, check the clearance between the gear and the sensor, and adjust if necessary. Clearance should be between 0.25 and 1.00 mm (0.010 and 0.040 inch) at the closest point. Make sure the gear has less than 0.50 mm (0.020 inch) diametric runout. See Manual 82510, *Magnetic Pickups for Electric Governors*.

2. Check for Grounds

Make sure power is off. Check for grounds by measuring the resistance from terminal 11 to chassis, and from terminal 15 to 11. The resistance should be infinite. If a resistance other than infinite is obtained, remove the connections from each terminal one at a time until the resistance is infinite. Check the line that was removed last to locate the fault.

Chapter 3. Operation and Adjustment

Initial Pre-Start Settings



Read this entire procedure before starting the prime mover.

1. RATED SPEED
 - A. Set the RATED SPEED potentiometer to minimum (fully counterclockwise).
 - B. Set the external Speed Trim, if used, to mid-position.
2. RESET—Set at mid-position.
3. GAIN—Set at mid-position.
4. ACCEL RAMP TIME—Set at maximum (fully clockwise).
5. DECEL RAMP TIME—Set at maximum (fully clockwise). (If no deceleration time is required, set fully counterclockwise.)
6. LOW IDLE SPEED—Set at maximum (fully clockwise).
7. LOAD GAIN—Set at mid-position.
8. DROOP—Set at minimum (fully counterclockwise).
9. ACTUATOR COMPENSATION.
 - A. Set the ACTUATOR COMPENSATION potentiometer at 2 on the 0 to 10 potentiometer scale for diesel, gas turbine, or fuel-injected gasoline prime movers.
 - B. Set the ACTUATOR COMPENSATION potentiometer at 6 on the 0 to 10 potentiometer scale for carbureted-gas or gasoline prime movers, and steam turbines.
10. START FUEL LIMIT—Set at maximum (fully clockwise).
11. Be sure that the actuator is connected to terminals 20 and 21.
12. Disable the temperature or process control by connecting terminals 16 and 30 (0 and 30 for high voltage control).
13. TEMP (PROCESS) GAIN—Set at mid-position.
14. TEMP (PROCESS) RESET—Set at mid-position.
15. TEMP (PROCESS) CONTROL—Set at maximum (fully clockwise).

Start-Up Adjustments

1. Complete the installation checkout procedure in Chapter 2, and the initial prestart settings above.

NOTICE

Be sure the speed range switch is set on the right speed range for your application as described in Chapter 2.

2. Close the Close For Rated contact. Set the control for isochronous operation by closing the droop contact.

IMPORTANT

This is for initial prime mover start-up only. For normal start-up, the Close For Rated contact (open for idle/close for rated) should be open if the prime mover is to start at idle.

3. Apply input power to the control.
4. Preset rated speed.

If a signal generator is not used, set the RATED SPEED potentiometer at minimum (fully counterclockwise).

When using a signal generator to set rated speed, set the signal generator for the frequency of the speed sensor at rated speed, and connect it to terminals 28 and 29. (The rated speed frequency in Hz equals the rated prime mover speed in rpm times the number of teeth on the speed-sensing gear divided by 60.) Put the Close For Rated contact in the rated (closed) position. Set the speed trim potentiometer, if used, to mid-position. Connect a dc analog voltmeter to terminals 20 (+) and 21 (–) to read actuator voltage.

If the actuator voltage is at minimum (minimum will be approximately 0 volts), slowly turn the RATED SPEED potentiometer clockwise (counterclockwise for reverse-acting controls) until the voltage just begins to move to maximum.

If the actuator voltage is at maximum, slowly turn the RATED SPEED potentiometer counterclockwise (clockwise for reverse-acting controls) until the voltage just begins to move to minimum.

Continue to very slowly adjust the RATED SPEED potentiometer in the appropriate direction, trying to stop the actuator voltage between the minimum and maximum voltages. Because it is not possible to stop the motion, cease adjusting when the voltage changes slowly. The RATED SPEED potentiometer is now set very close to desired speed. A slight adjustment when the engine is running will achieve the exact speed.



5. Check the speed sensor.

Minimum voltage required from the speed sensor to operate the electronic control is 1.0 Vrms, measured at cranking speed or the lowest controlling speed. For this test, measure the voltage while cranking, with the speed sensor connected to the control. Before cranking, be sure to prevent the prime mover from starting. At 5% of the lower value of the control's speed range, the failed speed sensing circuit is cleared. For example 100 Hz is required on the 2000 to 6000 Hz speed range ($2000 \text{ Hz} \times 0.05 = 100 \text{ Hz}$).



WARNING

Be prepared to make an emergency shutdown when starting the engine, turbine, or other type of prime mover, to protect against runaway or overspeed with possible personal injury, loss of life, or property damage.

6. Start the prime mover.

Adjust For Stable Operation

If prime-mover operation is stable, go to the "Speed Setting Adjustment" procedure.

If the prime mover is hunting at a rapid rate, slowly decrease the GAIN (turn the potentiometer counterclockwise) until performance is stable. Adjusting the GAIN may cause a momentary speed change which can be minimized by turning the GAIN potentiometer slowly.

If the prime mover is hunting at a slow rate, increase the RESET (turn the potentiometer clockwise) until the prime mover stabilizes. If increasing the RESET potentiometer does not stabilize the prime mover, it also may be necessary to either:

- Slowly decrease the GAIN (turn the potentiometer counterclockwise) or
- Slowly decrease the GAIN and increase the ACTUATOR COMPENSATION.

Speed Setting Adjustment

With the prime mover operating stably, and the external speed trim potentiometer (if used) set at mid-position, adjust the RATED SPEED potentiometer to bring the prime mover to the desired operating speed.

Dynamic Adjustment

The object of the GAIN and RESET potentiometer adjustment is to obtain the optimum, or desired, stable prime-mover-speed response.

Connect a dc analog voltmeter to terminals 20 (+) and 21 (–) to monitor the actuator voltage.

IMPORTANT

Adjusting the GAIN may cause momentary changes in speed which can be minimized by turning the GAIN potentiometer slowly.

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Increasing the setting of the GAIN potentiometer provides faster transient response (decreases the magnitude of the speed change from a sudden change in load). To achieve optimum response, slowly increase the GAIN (turn the potentiometer clockwise) until the voltage on the voltmeter becomes slightly unstable, then slowly turn the GAIN back counterclockwise as necessary to stabilize the meter reading. Step load the generator, or bump the actuator terminal shaft, to make sure that the prime mover returns to the proper speed with little overshoot or undershoot of the speed setting. To reduce overshoot, increase the RESET (turn the potentiometer clockwise).

When the RESET potentiometer is in the lower part of its adjustment (0 to 3 on the potentiometer scale), increasing the RESET clockwise may require decreasing the GAIN (turning the GAIN potentiometer counterclockwise) to maintain stable operation.

If the prime mover is slow in returning to the proper speed, decrease the RESET by turning the potentiometer counterclockwise.

Figure 3-1 illustrates prime mover starts with the RAMP TIME potentiometer fully counterclockwise (no ramp), step loadings at four different RESET potentiometer settings, and stable, steady-state running conditions. These are typical performance curves on a naturally aspirated (non-turbocharged) diesel engine.

IMPORTANT

Optimum performance is not necessarily obtained with the GAIN potentiometer at the maximum stable clockwise position. In some cases, the gain must be reduced slightly to ensure stability under widely varying conditions.

Actuator Compensation Adjustment

If the ACTUATOR COMPENSATION is set as described under Initial Prestart Settings, no further adjustment is normally required. If a slow periodic instability remains, slightly increase the ACTUATOR COMPENSATION (turn the potentiometer clockwise), and repeat the GAIN and RESET adjustments. Continue to increase the ACTUATOR COMPENSATION and readjust the GAIN and RESET until stability is achieved.

If a fast instability or extremely active actuator is evident, slightly decrease the ACTUATOR COMPENSATION (turn the potentiometer counterclockwise). If necessary, the ACTUATOR COMPENSATION may be set fully counterclockwise. This may be required when engine torsionals cause excessive fuel-linkage movement.

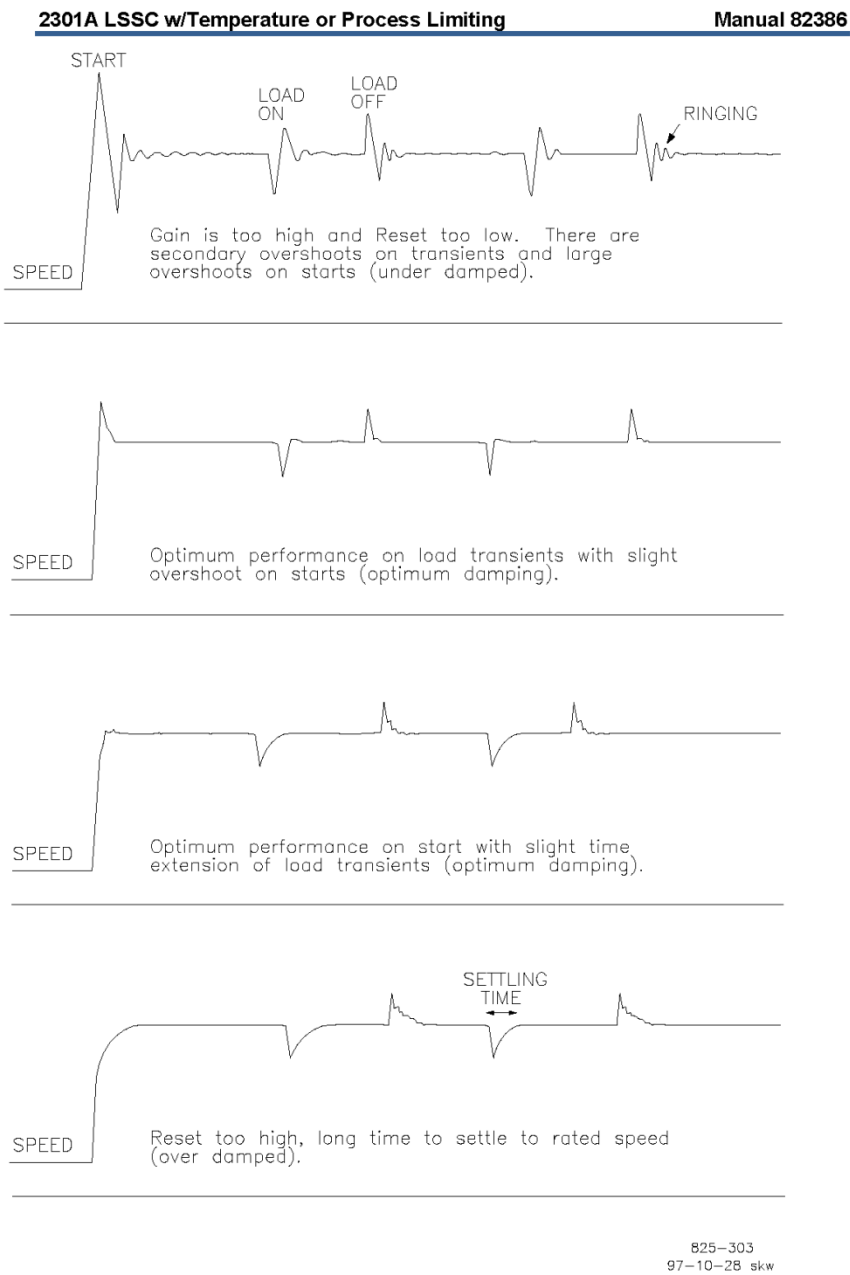


Figure 3-1. Diesel Engine Performance Curves



Low Idle Speed Adjustment

1. The prime mover should be approximately at rated speed with the LOW IDLE SPEED potentiometer set at maximum (fully clockwise). Open the external CLOSE FOR RATED contact.
2. Decrease the LOW IDLE SPEED (turn the potentiometer counterclockwise) until the recommended idle speed is reached.

IMPORTANT

Make certain that the prime-mover speed is controlled by the LOW IDLE SPEED potentiometer in a range above the minimum-fuel position (mechanical stop) of the actuator or prime-mover fuel rack.

Accel Ramp Time Adjustment

Adjust the RAMP TIME ACCEL potentiometer to achieve satisfactory prime mover acceleration to rated speed with minimum overshoot. First, start at the fully clockwise (maximum ramp time) position and work back in the counterclockwise direction until the unit ramps as rapidly as desired.

Decel Ramp Time Adjustment

Adjust the RAMP TIME DECEL potentiometer for the desired deceleration rate. Start at the fully clockwise (maximum ramp time) position and work back in the counterclockwise direction until the unit ramps as rapidly as desired.

Start Fuel Limit Adjustment

IMPORTANT

Start-fuel limit is not recommended for use with reverse-acting controls. With loss of speed signal, the reverse-acting control will position the actuator at the start-fuel level if the failed-speed-signal override is activated. Reverse-acting systems normally require the control to demand full fuel on loss of speed signal to allow the mechanical backup governor to control the system. The Start Fuel Limit can be deactivated by turning the potentiometer fully clockwise.

With the prime mover operating at rated speed and no load, record the voltage across actuator terminals 20 (+) and 21 (-). Shut down the prime mover and activate the Failed Speed Signal Override by closing the override contact. The voltage to the actuator should now be adjustable by the START FUEL LIMIT potentiometer. Set the actuator voltage approximately 10% higher than the voltage obtained at rated speed for forward-acting controls and 10% lower than rated speed voltage for reverse-acting controls. Remove the Failed Speed Signal Override contact if not required to start the prime mover.

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Start the prime mover and observe the start time, overshoot of speed setting, and smoke emissions obtained. The START FUEL LIMIT may be adjusted as required to optimize the prime-mover starting characteristics. The fuel-limiting function is turned off automatically when the speed control takes over.

IMPORTANT

For prime movers not requiring start-fuel limiting, the START FUEL LIMIT function can be deactivated by turning the potentiometer fully clockwise.

Speed Sensor Check

If the sensor is a magnetic pickup, measure the voltage across terminals 28 and 29 to be sure there is a minimum of 1.0 V at cranking speed, and a maximum of 30 Vrms at rated speed. If the voltage exceeds 30 V, increase the gap of the speed sensor, and be sure that there is still a minimum of 1.0 V at cranking speed.

Current Transformer (CT) Phasing Check

IMPORTANT

This control contains internal current transformers. Due to their low impedance, shorting their inputs is not effective. The current input must be removed from the control and shorted externally.

WARNING

HIGH VOLTAGE—Never disconnect any wire attached to load sensor terminals 4 through 9 when the prime mover is running unless temporary 1 Ω , 5 W resistors are installed as shown in Figure 3-2, and all load is removed. The current transformers can develop dangerously high voltages when open circuited while the prime mover is running.

1. Connect a dc voltmeter to control terminals 12 (–) and 13 (+) to measure the load signal.
2. Start the prime mover. With the generator operating in the isochronous mode and not paralleled, load the generator to as near to full load as possible. Measure the load-signal voltage.
3. Unload and shut down the prime mover. Disconnect the wire from terminal 5, and connect both wires from phase A CT to terminal 4.
4. Start the prime mover, apply full load (or the same load as obtained in step 2) and again measure the load signal at terminals 12 and 13. If the load signal voltage is not 1/3 lower than the reading obtained in step 2, the phasing is incorrect. Unload and shut down the prime mover. Reconnect phase A CT wire from terminal 4 to terminal 5, maintaining the original polarity.

If the phasing is incorrect, proceed to the Phase Correction Procedure.

If the phasing appears correct, skip the Phase Correction Procedure and go to the Load Gain Adjustment procedure.

IMPORTANT

If after completing the LOAD GAIN and DROOP adjustments, the control loading is extremely sensitive to changes in the power factor when operating in parallel, complete the Phase Correction Procedure.

Phase Correction Procedure

IMPORTANT

This procedure requires a minimum power factor of 0.9. If a 0.9 power factor cannot be obtained, tracing through the wiring is the only means of correcting the current-transformer phasing.

The highest positive voltage will be obtained when the CTs are correctly matched to the load-sensor terminals in both phase and polarity. The following procedure will assure the correct connection of the current transformers. It is required only if the phasing check indicates incorrect phasing, or loading stability is extremely sensitive to the power factor.

Trial connections of the first CT to all three load-sensor inputs, polarized both ways, are made (a total of six connections). The load-signal voltage is recorded for each connection and the first CT is then connected to the terminals that produce the highest positive voltage, and with the polarity that produces the highest positive voltage.

The second CT is tried on each of the remaining two CT input terminals, in each polarity, and the voltage recorded. The second CT is then connected to the terminals that produce (and with the polarity that produces) the highest positive voltage.

The last CT is then tried on the remaining input terminals, polarized both ways, and the voltage recorded. Connecting the last CT in the polarity that produces the highest voltage completes the procedure.

The Phase Correction Procedure requires that the prime mover be shut down many times to disconnect the current transformers. For convenience, a temporary method of connecting the current transformers shown in Figure 3-2 is recommended. Connecting a 1 Ω , 5 W burden resistor across each current transformer allows the current transformers to be disconnected from the terminal strip with the prime mover running, after removing all load.

WARNING

HIGH VOLTAGE—The current transformers can develop dangerously high voltages. Do not disconnect a current transformer while the prime mover is running unless temporary 1 Ω , 5 W resistors are installed as shown in Figure 3-2, and all load is removed.

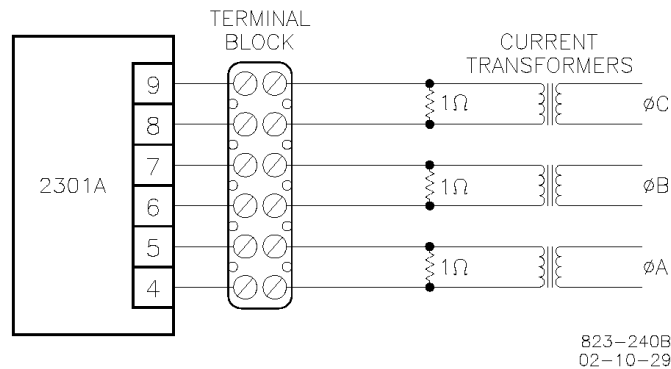


Figure 3-2. Temporary Wiring for Transformer Phase Correction

If the temporary burden resistors described above and shown in Figure 3-2 are not used, the prime mover **MUST** be shut down in addition to removing the load in the following procedure.

Measure the load-signal voltage in this procedure by connecting a voltmeter across the Load Signal terminals 12 (–) and 13 (+).

1. Shut down the prime mover.
2. Label each CT wire with the phase and polarity that you think it should be. Even though this identification may prove to be incorrect, this step is necessary so that the individual wires may be identified during the description of the procedure.
3. Disconnect the phase B CT wires from terminals 6 and 7. Connect these two wires together using a small screw and nut, and tape the connection.
4. Disconnect the phase C CT wires from terminals 8 and 9. Connect and tape these two wires together as in step 3.
5. Connect the two wires from the phase A CT to the phase A input terminals 4 and 5.
6. Start the prime mover, apply full load, and measure the load signal voltage. Start a list and record this voltage.
7. Unload the system and reverse the phase A CT wires on terminals 4 and 5. *
8. Apply full load, measure the load signal, and record this voltage.
9. Unload the system, remove the phase A CT wires from terminals 4 and 5, and connect them to phase B input terminals 6 and 7. *
10. Apply full load, measure the load signal, and record this voltage.

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11. Unload the system and reverse the phase A CT wires on terminals 6 and 7. *
12. Apply full load, measure the load signal, and record this voltage.
13. Unload the system, remove the phase A CT wires from terminals 6 and 7, and connect them to phase C input terminals 8 and 9. *
14. Apply full load, measure the load signal, and record this voltage.
15. Unload the system and reverse the phase A CT wires on terminals 8 and 9. *
16. Apply full load, measure the load signal, and record this voltage.
17. Unload the system and compare the six voltage readings. *
18. Remove the phase A CT wires from terminal 8 and 9 and connect the phase A wires to the pair of terminals that produced the highest positive load-signal voltage and in the polarity that produced the highest positive load-signal voltage.
19. Untape and disconnect the phase B CT wires. Connect the phase B CT wires to one pair of the two remaining pair of CT input terminals on the load sensor.
20. Apply full load and measure the load signal. Start a new list and record this voltage.
21. Unload the system, and reverse the phase B CT wires on the same terminals. *
22. Apply full load, measure the load signal, and record this voltage.
23. Unload the system, remove the phase B CT wires, and connect them to the other pair of terminals. *
24. Apply full load, measure the load signal, and record this voltage.
25. Unload the system and reverse the phase B CT wires on the same terminals. *
26. Apply full load and measure the load signal. Record this voltage, and compare the four voltages on the list.
27. Unload the system. Remove the phase B CT wires and connect them to the pair of CT input terminals that produced the highest positive load signal voltage and with the polarity that produced the highest positive load signal voltage. *
28. Untape and disconnect the phase C CT wires. Connect these two wires to the remaining pair of CT input terminals.
29. Apply full load, measure the load signal, and record this voltage.
30. Unload the system and reverse the phase C CT wires on the same terminals. *



31. Apply full load, measure the load signal, and record this voltage.
32. Unload and shut down the system. Compare the two voltages. *
33. Connect the phase C CT wires to the same pair of CT input terminals, but in the polarity that produced the highest positive load-signal voltage.
34. Re-label each wire with the phase designation of the terminal that it is now connected to.
35. Remove the burden resistors and terminal block.

***—Be sure to shut down the prime mover if the temporary burden resistors are not used.**

Load Gain Adjustment

For this procedure, the generator must be running isochronously and not paralleled. Connect a dc voltmeter across terminals 12 (–) and 13 (+) to measure the load-signal voltage.

Start the prime mover and apply full load. Measure the load signal voltage and adjust the LOAD GAIN potentiometer for 6.0 V. * If full load is not obtainable, decrease the LOAD GAIN proportionally to the load. For example, at 50% load adjust the LOAD GAIN to 3 V.

When paralleled in the isochronous mode or on an isolated bus, generator speeds must be the same. If they are not equal, load sharing will not remain proportional as the load varies. Any difference in loads between the units can be corrected by adjusting the Load Gain Potentiometer. Increasing the LOAD GAIN (turning the potentiometer clockwise) will cause that generator to carry less load. If stability problems occur when paralleled at a particular load-signal voltage, reduce the voltage by reducing the LOAD GAIN (turn the potentiometer counterclockwise), and reduce the load-signal voltage setting of all other generators in the system to the same voltage. When the load-signal voltages of all generators in a system are reduced, the load-sharing gain will be reduced, and this may result in some loss of load-sharing sensitivity.

- * If 6 volts at full load (or a lower voltage proportional to a load less than 100%) cannot be obtained, and the phasing has been checked and is correct, the current transformers are probably the wrong size. The current-transformer output must be from 3 to 7 A (5 A nominal) at full load.

It may be necessary to reduce the load-signal voltage of each unit in the system to as low as 3 V in cases of extremely poor system dynamics. If your system requires a load-signal voltage as low as 3 V, consult Woodward for suggestions for possible remedies.



Droop Adjustment

Adjustment of the DROOP potentiometer is necessary when the generator set is to be operated in the droop mode. Droop in a load sensor is usually expressed as a percentage and calculated by the following formula.

$$\% \text{ Droop} = \frac{\text{No Load Speed} - \text{Full Load Speed}}{\text{No Load Speed}} \times 100$$

The method of setting droop depends on whether the load of the generator set is an isolated load or an infinite bus.

Setting Droop for an Isolated Load

1. Open the droop contact connected to terminal 14.
2. Start the prime mover and adjust the RATED SPEED potentiometer for rated speed with no load.
3. Apply full load. *
4. Adjust the DROOP potentiometer to give the desired speed.

Example: Operating at 60 Hz, 57 Hz at full load indicates 5% droop.

*—If only 50% loading is possible, 58.5 Hz would indicate 5% droop (see Figure 3-3).

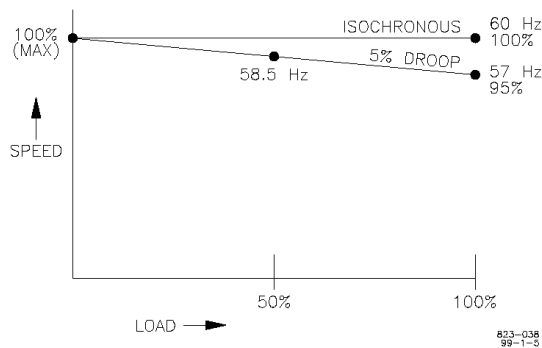


Figure 3-3. Droop Adjustment

Setting Droop for an Infinite Bus Load

1. With the generator not paralleled, adjust the RATED SPEED potentiometer to give a speed setting above 60 Hz by the percent of droop required.

Example: Droop of 5% would require raising the speed to 63 Hz.

2. Mark the potentiometer position and re-adjust the RATED SPEED potentiometer for 60 Hz.
3. Turn the DROOP potentiometer fully clockwise (for maximum droop).

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4. Open the droop contact connected to terminal 14.
5. Synchronize the generator with the bus and close the tie-breaker. (Parallel the generator with the bus.)
6. Return the RATED SPEED potentiometer to the mark made in step 2.
7. Adjust the droop potentiometer counterclockwise, decreasing droop, until 100% load is achieved.*

* If it is necessary to set the droop with less than 100% load, set the RATED SPEED potentiometer (in step 1) accordingly, for the desired percent of droop.

Example: At 5% droop, running at only 50% load, the RATED SPEED potentiometer would be set at 61.5 Hz in Step 1.

Temperature Limiting Adjustments



WARNING

Be prepared to make an emergency shutdown when starting the engine, turbine, or other type of prime mover, to protect against runaway or overspeed with possible personal injury, loss of life, or property damage.



WARNING

During this calibration procedure, monitor the prime mover temperature with a separate temperature-measurement device, and be prepared to shut the prime mover down if the temperature rises above a safe level.

1. Following the manufacturers instructions, start the prime mover parallel with the utility, and apply load in droop until the temperature rises to the desired control level.
2. Make sure the temperature limiter is enabled (terminal 0 not connected to terminal 30 [high-voltage control] or terminal 16 not connected to terminal 30 [low-voltage control]).
3. Slowly turn the temperature limit potentiometer counterclockwise until the TEMP IN CONTROL LED illuminates.

Process Limiting Adjustments



WARNING

Be prepared to make an emergency shutdown when starting the engine, turbine, or other type of prime mover, to protect against runaway or overspeed with possible personal injury, loss of life, or property damage.



WARNING

During this calibration procedure, use a voltmeter or milliammeter to monitor the process signal carefully and be prepared to shut the prime mover down if the process signal rises above a safe level.

1. Following the manufacturer's instructions, start the prime mover and increase speed or apply load until the process signal rises to the desired control level.
2. Make sure the process limiter is enabled (terminal 0 not connected to terminal 30 (high-voltage control) or terminal 16 not connected to terminal 30 (low-voltage control)).
3. Slowly turn the PROCESS CONTROL potentiometer counterclockwise until the PROCESS IN CONTROL LED illuminates.
4. Adjust the GAIN and RESET controls together to give maximum sensitivity with stability as follows:
 - a. Turn the gain potentiometer clockwise until temperature oscillations just start.
 - b. Turn the GAIN control counterclockwise until the oscillations just stop.
 - c. Set the RESET potentiometer for the desired response. This adjustment determines how the control will respond to transients. A high (clockwise) setting will provide slow, well-behaved recoveries. A low (counter-clockwise) setting will provide quick recoveries with possible overshoot.

Chapter 4. Description of Operation

Introduction

The speed and load sharing section of these 2301A models monitors and controls two functions.

- **Speed**—The speed control section keeps the prime mover at the correct speed.
- **Load Sharing**—During parallel operation of two or more generators, the load sharing section senses the load carried by its generator and causes the loads of all generators in the system to be shared proportionally.

The temperature process limiting section of these 2301 A models monitors and either limits temperature (in temperature limiting models) or controls a process-derived signal (in process limiting models). The temperature limiting or process control section of these 2301 A controls can be enabled or disabled by a switch or contact input to the control.

When the temperature limiting (or process limiting) section is enabled, only the control section calling for the lower amount of fuel (either the speed and load sharing section, or the temperature limiting or process control section) will be in control of the prime mover. For example, if temperature limiting is enabled, but is calling for a fuel level greater than that called for by the speed and load-sharing section, the speed and load sharing section will be in control of the prime mover.

Speed Control

The Speed Control system as shown in Figure 4-1 consists of:

- a device (1) to sense the speed of the prime mover
- a Frequency to Voltage Converter (2)
- a Speed Reference (3) to which the prime mover speed can be compared
- A Speed Summer/Amplifier (4) with an output proportional to the amount of fuel or steam required to maintain the desired speed at any given load
- An Actuator (5) to position the fuel or steam mechanism of the prime mover

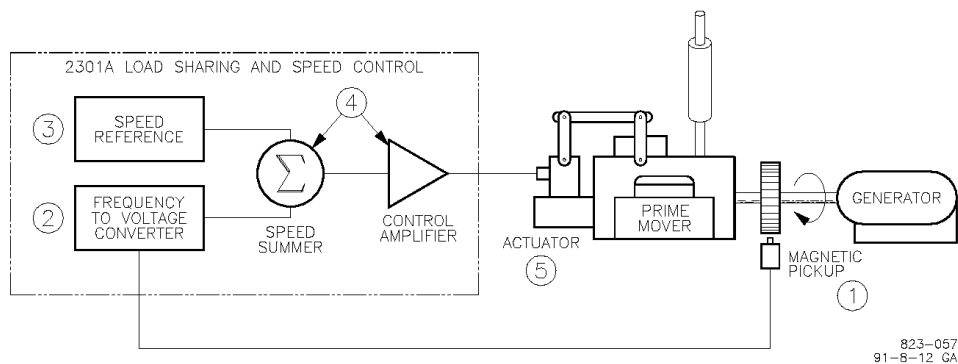


Figure 4-1. Speed Control System

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A speed-sensing device, such as a magnetic pickup, senses the speed of the prime mover, and converts it to an ac signal with a frequency proportional to prime-mover speed.

The frequency-to-voltage converter receives the ac signal from the speed sensor and changes it to a proportional dc voltage.

A speed-reference circuit generates a dc "reference" voltage to which the speed-signal voltage is compared. See Woodward manual 82510, *Magnetic Pickups & Proximity Switches for Electronic Controls*, for more information on magnetic pickups.

The speed-signal voltage is compared to the reference voltage at the summing point. If the speed-signal voltage is lower or higher than the reference voltage, a signal is sent by the control amplifier calling for an increase or decrease in speed.

The actuator responds to the signal from the control amplifier by repositioning the fuel or steam rack, changing the speed of the prime mover until the speed-signal voltage and the reference voltage are equal.

A failed-speed-signal circuit monitors the speed-signal input. When no signal is detected, it calls for minimum fuel. The minimum-fuel signal is sufficient to cause the actuator to go to the minimum position if not restricted. However, due to linkage adjustment or other restrictions in the external system, minimum actuator position may not permit prime-mover shutdown.

For controls with actuator current of 20 to 160 mA, minimum fuel is defined as:

- Actuator current less than 10 mA for forward-acting controls.
- Actuator current greater than 180 mA reverse-acting controls.

For controls with actuator current of 40 to 320 mA, minimum fuel is defined as:

- Actuator current less than 20 mA for forward-acting controls.
- Actuator current greater than 360 mA for reverse-acting controls.

A contact to override the failed-speed-signal circuit can be connected in series with terminal 18 and terminal 16 (or terminal 0 on high voltage controls). Temporarily closing the contact overrides the failed-speed-signal circuit, which may be required for start-up.

Because of the variety of installations, plus system and component tolerances, the control must be tuned to each system for optimum performance. The potentiometers for setting and adjusting these circuits are located in the upper right corner of the control as shown in Figure 4-2. They include:

- the RATED SPEED potentiometer
- the START FUEL LIMIT potentiometer
- RESET, GAIN, and ACTUATOR COMPENSATION
- ACCEL RAMP TIME, DECEL RAMP TIME, and LOW IDLE SPEED potentiometers

The RATED SPEED potentiometer is adjusted so that at rated speed, the converter-speed voltage and the reference-speed voltage are equal.

The START FUEL LIMIT potentiometer provides a means of limiting the fuel-rack position when starting diesel engines. Adjustment of the potentiometer sets the maximum actuator position desired. This limit position is automatically enabled prior to start-up, and is turned off when speed control takes over.



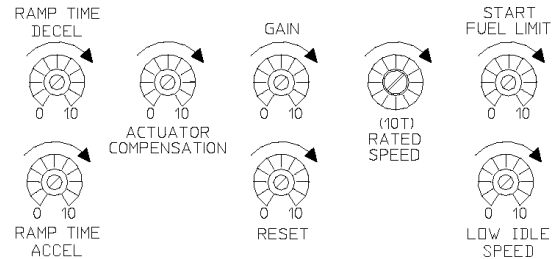


Figure 4-2. Speed Control Adjustments

RESET, GAIN and ACTUATOR COMPENSATION potentiometers adjust the control amplifier to accommodate various types of prime-mover systems. The RESET adjustment affects prime mover reaction time when recovering after a sudden load change. The magnitude of the speed change resulting from a sudden change in load is controlled by adjusting the GAIN. ACTUATOR COMPENSATION compensates for the time the actuator and prime mover system takes to react to signals from the control.

The time taken by the prime mover to accelerate from idle to rated speed, and the recommended idle speed, are set with the RAMP TIME and LOW IDLE SPEED potentiometers respectively.

Acceleration Ramp

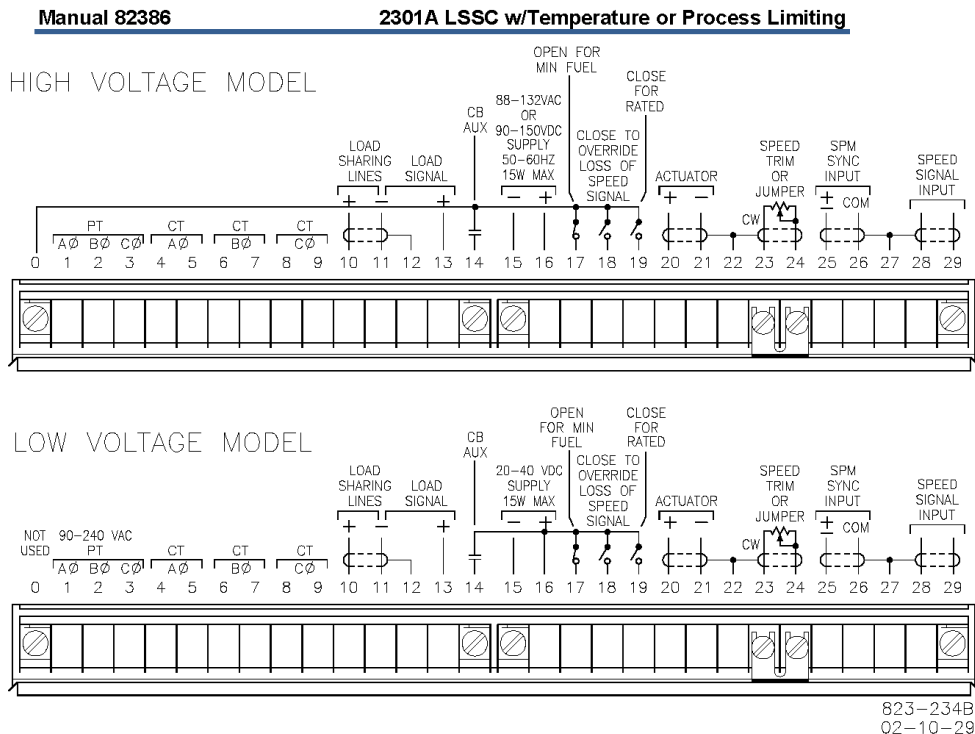
The time the control takes to go from idle speed to rated speed (when the IDLE/RATED contacts are closed) can be varied from 0 to approximately 20 seconds by adjusting the ACCEL RAMP TIME potentiometer.

Deceleration Ramp

The time the control takes to go from rated speed to idle speed (when the IDLE/RATED contacts are opened) can be varied from 0 to approximately 20 seconds by adjusting the DECEL RAMP TIME potentiometer.

Terminals for External Devices

Terminal blocks for wiring the control to the system are at the lower front panel of the control. Additional terminals are included for connecting other external devices as shown in Figure 4-3.



NOTES

- Terminal 0**—On high voltage models, this terminal provides +20 Vdc for input terminals 14, 17, 18, 19, and 30. On low voltage models, this terminal is not used.
- Terminal 14**—When contact is closed, control is in isochronous and the load sharing lines are active. When open, control is in droop and the load sharing lines are disabled.
- Terminal 16**—On low voltage models, this terminal provides a +dc source for input terminals 14, 17, 18, 19, and 30, and is the dc supply + connecting point. On high voltage models, this terminal is either one of the ac input terminals (on ac supply) or the dc + connecting point (on dc supply).
- Terminal 17**—A contact to drive the output to minimum fuel when required for shutdown.* The jumper must *not* be used on high voltage models.
- Terminal 18**—A contact to override the failed speed protective circuit for start-up and start fuel setup calibration.
- Terminal 19**—A contact to accelerate from idle to rated speed when the contact is closed.
- Terminals 23 and 24**—An external means of remotely fine tuning the speed setting. It also may be used for manual synchronization or for loading the generator when operating in droop mode.
- Terminals 25 and 26**—Provide for use of an optional speed and phase matching (SPM) synchronizer. An SPM synchronizer automatically generates a signal to bias the speed of the prime mover of an off-line generator so that its frequency and phase match those of the bus.**

*—Do *not* use the minimum fuel contact option as part of any emergency stop sequence.

**—See Woodward manual 82384, *SPM-A Synchronizer 9905-002*, for more information on the SPM-A.

Figure 4-3. Terminal Connections

Paralleling

There are two basic methods used for paralleling: droop, where speed decreases with load, and isochronous, where speed remains constant. The paralleling system as shown in Figure 4-4 consists of:

- Load Matching circuit (1)
- a Load Amplifier circuit (2)

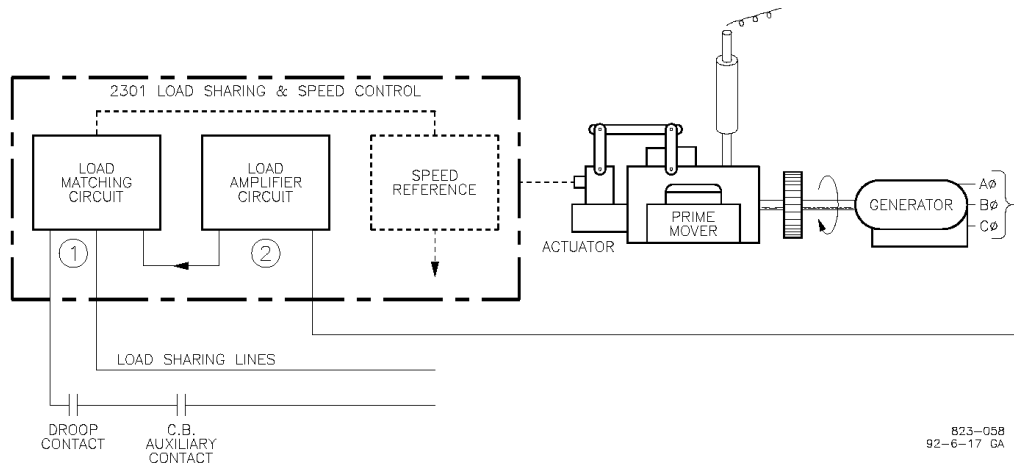


Figure 4-4. Paralleling System

An auxiliary contact on the generator tie-breaker connected from terminal 16 (or terminal 0 on high voltage controls) to terminal 14 is used to select isochronous load-sharing operation. A contact in series with the auxiliary contact may be used to select either the droop or isochronous mode of operation.

If either the auxiliary contact or the droop contact is open, the control is in droop. When they are both closed, the control is in isochronous load sharing.

With only one unit on line, the generator picks up the available load and remains at isochronous speed. If additional units are on line, the Load Matching circuit corrects the fuel output to proportion load.

An amplifier in the load-sensing circuit computes the load carried by each phase of the generator. The current load on each phase is multiplied by the cosine of the phase difference between the current and the voltage, and the three phases are added to determine the total load.

The output of the load amplifier is adjusted by the LOAD GAIN potentiometer shown in Figure 4-5. By setting the load-gain voltage on each unit to the same level at full load, proportional load sharing is achieved. Regardless of differences in generator-set capacities in the system, each generator set is loaded to the same percentage of its capacity. A final adjustment of the individual LOAD GAIN potentiometers will compensate for minor differences in the generator sets.

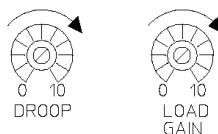


Figure 4-5. Paralleling Adjustments

As mentioned in the general information section, droop mode allows operation of a generator on an infinite bus or in parallel with other engine generator units using hydromechanical governors. In droop, speed changes as the load on the generator changes. An increase in load results in a decrease in speed. The amount of speed change or droop is expressed in percent, and is set by the DROOP potentiometer shown in Figure 4-5.

The 2301A Load Sharing and Speed Control is powered by a dc-dc isolated power supply, which allows operation over a wide voltage range without generating excessive heat. This isolation protects the system from interference caused by ground loops, particularly through the load-sharing lines, and allows load sharing with earlier models of Woodward load-sharing controls.

Process and Temperature Limiting

This 2301 A control also can control the prime mover in either the temperature limiting mode or process limiting mode (separate models) (low signal selected with the load-sharing and speed control section). The models with temperature limiting use a type K thermocouple, and the models with process limiting accept either a 4 to 20 mA or a 1 to 5 Vdc signal.

The control includes terminals for connecting a switch or contact to enable and disable the temperature (or process) limiting section.

The Temperature Limiting/Process Limiting circuitry has a failed input signal circuit which monitors the thermocouple or process input. This circuit asks for a minimum fuel level if the thermocouple drops below 204 °C (400 °F) or the process input drops below 0.5 V or 2 mA. This function is overridden when the "close to disable temperature limiting (or process limiting)" contact is open. It may be required in some cases to open this contact to enable start up but should only be momentarily open.

Figure 4-6 shows the potentiometers and LED associated with the temperature limiting process control section.

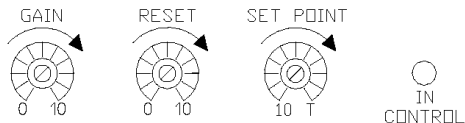


Figure 4-6. Temperature Limiting/Process Limiting Section

Chapter 5. Troubleshooting

The following troubleshooting guide is an aid in isolating trouble to the control box, actuator, plant wiring, or elsewhere. Troubleshooting beyond this level is recommended ONLY when a complete facility for control testing is available.

NOTICE

The control can be damaged with the wrong voltage. When replacing a control, check the power supply, battery, etc., for the correct voltage.

Troubleshooting Procedure

Table 5-1 is a general guide for isolating system problems. This guide assumes that the system wiring, soldering connections, switch and relay contacts, and input and output connections are correct and in good working order. Make the checks in the order indicated. Various system checks assume that the prior checks have been properly done.

WARNING

Be prepared to make an emergency shutdown when starting the engine, turbine, or other type of prime mover, to protect against runaway or overspeed with possible personal injury, loss of life, or property damage.

Table 5-1. Troubleshooting

Symptom	Cause	Remedy
Prime mover will not start. Actuator not moving to start-fuel position. NOTE —If the actuator moves to start position, a problem with the prime mover fuel supply is indicated.	Supply voltage polarity reversed (dc only), or no supply voltage.	Check for proper voltage from terminals 16 (+) to 15 (–). Reverse leads if polarity is incorrect (dc only).
	Actuator not responding to input signal from control. NOTE <i>The hydraulic actuator must have oil pressure and gear rotation to operate (respond).</i>	If there is a voltage output at control terminals 20 (+) and 21 (–), but the actuator does not move, the wiring to the actuator should be checked for opens or shorts. With the EG3P actuator, remember that terminals C and D of the mating plug should be jumpered. Make resistance checks at the actuator. Coil resistance on Woodward actuators is approximately 35 Ω. (Read with leads at T20 and T21 disconnected.)
	Start fuel limit set too low.	Turn start fuel limit clockwise until prime mover starts.
	Actuator or Linkage.	Check actuator and linkage for proper installation and operation. Problems may be oil supply, direction of rotation, insufficient drainage, linkage, worn actuator components, or improper adjustment.

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Symptom	Cause	Remedy
Prime mover will not start. Actuator not moving to start-fuel position. (cont.)	No actuator voltage at terminals 20 and 21.	Check for shorted or grounded actuator leads by removing wires to terminals 20 and 21. Stop prime mover. Close the switch on terminal 18, short terminal 23 to 24. Check for 18 to 22 volts at terminals 20 and 21 for forward acting controls, and 0 to 1 volt for reverse acting controls. Check for at least 1 Vrms at terminals 28 and 29, and at least 5% of the minimum rated speed frequency range.
	Speed setting too low on initial start.	Control may be the wrong speed range. Check speed sensor frequency versus control part number. Speed setting may be lower than cranking speed. Control should be set for rated speed. Increase RATED SPEED setting clockwise. NOTICE If adjusting RATED SPEED setting clockwise does not produce the correct output, return RATED SPEED setting to normal start position—full counterclockwise.
	LOW IDLE SPEED setting may be set too low.	Adjust LOW IDLE SPEED potentiometer clockwise.
	Minimum Fuel contact open. See "Minimum Fuel Contact" in Chapter 2.	Check T 17. Minimum-fuel contact must be closed for normal operation. Check for 20 to 40 Vdc from terminal 17 (+) to 15 (-).
	Speed sensor signal not clearing failed speed signal circuit.	Check wiring for proper connection. Check shields for proper installation. Speed sensor not spaced properly—check for at least 1.0 Vac at terminals 28 and 29 during cranking. If less than 1.0 Vac, magnetic pickup may be spaced too far from gear. Make sure there are no metal chips on end of pickup. If no voltage is present, magnetic pickup may be open-circuited or shorted. Make resistance check with the leads disconnected from control. Should be about 100 to 300 Ω . Failed speed-signal circuit may be disabled by connecting terminal 16 (or terminal 0 on high voltage controls) to terminal 18. WARNING Be prepared to make an emergency shutdown when starting the engine, turbine, or other type of prime mover, to protect against runaway or overspeed with possible personal injury, loss of life, or property damage.



2301A LSSC w/Temperature or Process Limiting

Manual 82386

Symptom	Cause	Remedy
Prime mover will not start. Actuator not moving to start-fuel position. (cont.)	Terminals 23 and 24 are open.	Verify that terminals 23 and 24 are jumpered if optional external speed trim is not used.
	Faulty speed trim potentiometer.	With power OFF, check speed trim potentiometer(s) with an ohmmeter.
	Faulty 2301A control.	Replace control.
	Temperature or process signal may be limiting the actuator signal. (Check if the TEMP (or PROC) IN CONTROL LED is illuminated.)	Check the TEMP (or PROC) SET POINT potentiometer and adjust if necessary. Replace temp or process sensor or repair wiring if necessary.
Thermocouple or process signal not clearing the failed input signal circuit.	Check for at least of 0.5 Vdc or 2 mA process input on 204 °C (400 °F) thermocouple input.	Momentarily disable temperature limiting or process limiting if necessary for start-up.
Prime mover will not start (high-voltage control).	Common + source for contacts connected to terminals 14, 17, 18, and 19 taken from terminal 16 instead of from terminal 0.	Connect + source for these terminals to terminal 0, not 16.
Prime mover overspeeds only on starts.	Ramp adjustment.	Increase RAMP TIME (clockwise). This decreases acceleration rate (from low idle to rated).
	RATED SPEED setting too high.	Set RATED SPEED as described in Chapter 3.
	Amplifier adjustment.	Amplifier may be adjusted for sluggish operation, causing overspeed on start. Slowly adjust GAIN for fastest stable response. RESET may be adjusted too low, increase RESET setting.
	Determine if engine is malfunctioning.	Verify that fuel rack is not binding and linkage is properly adjusted. Determine if the fuel rack is quickly following the actuator input voltage. Check operation of overspeed protection device(s).
	2301A control.	If the control does not cut back the actuator voltage [T 20 (+) and T 21 (-)] until the speed setting is completely counterclockwise (or does not reduce fuel at any position), the 2301A control may be faulty, or may have the wrong speed range. If the voltage is cut back, look for a problem in the linkage or actuator.
Prime mover overspeeds after operating at rated speed for some time.	Prime mover.	Check for proper operation of prime-mover fuel system. If actuator moves toward minimum fuel during overspeed, problem is in fuel system.
	Magnetic pickup and 2301A control.	Check the magnetic-pickup output voltage at speeds above idle—at least 1.0 Vrms. If magnetic pickup should fail and the override-failed-speed-signal circuit is disabled, the 2301A control will call for maximum fuel.
	2301A control amplifier.	Control the prime mover manually at rated speed and adjust the RATED SPEED setting fully counterclockwise. If the output voltage is not zero, check for proper speed range switch adjustment as described in Chapter 2. If speed range is correct for the application, replace the control.



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Symptom	Cause	Remedy
Prime mover has momentary speed change when adjusting GAIN.	GAIN adjustment made too quickly.	Make GAIN adjustment slowly. Small momentary speed changes when adjusting GAIN is normal.
Low speed is not regulated by LOW IDLE SPEED potentiometer.	NOTE <i>On carbureted prime movers, the minimum fuel stop rpm setting will vary with prime mover temperature. An improper cold setting may give interference with the LOW IDLE SPEED setting when the prime mover is hot.</i>	The LOW IDLE SPEED setting may be below the minimum-fuel position of the actuator or prime-mover fuel stop. In this case, the output voltage to the actuator will be zero. The engine will be maintained at the minimum-fuel position by the actuator or the prime mover minimum-fuel stop. The conditions above indicate that the prime mover minimum-fuel position should be decreased by linkage adjustment (diesel engine) or low-idle set screw (gas engine), or the LOW IDLE SPEED setting should be raised. If the above action does not correct the problem, the 2301A control may be faulty.
	LOW IDLE SPEED potentiometer.	If adjustment of the LOW IDLE SPEED potentiometer causes erratic behavior, replace the control.
Prime mover does not decelerate when Close for Rated contact is open.	Faulty Close for Rated contact.	Check Close for Rated contact. Remove wire from terminal 19. Prime mover should decelerate.
	LOW IDLE SPEED set fully clockwise.	Turn LOW IDLE SPEED setting counterclockwise with terminal 19 open.
	2301A control ramp circuitry.	A faulty Close for Rated contact may remain in the accelerate position with the contact open. If the Close for Rated contact is operative, loss of idle control may be due to a faulty circuit. In general, adjustment of LOW IDLE SPEED will vary the speed of the prime mover with the Close for Rated contact in the decelerate (open) position. Adjustment of LOW IDLE SPEED should not affect prime mover speed when the Close for Rated contact is closed. WARNING The speed-setting controls have sufficient range to override the ramp and bring the prime mover speed up to rated while still in the low-idle mode (either by defect or switching). Therefore, a Close for Rated contact that is intermittent may cause the prime mover to overspeed if the RATED SPEED setting is adjusted for rated speed with T19 open.
Prime mover will not stabilize at rated no load speed. The instability may occur at no load or it may vary with load. Control may be erratic.	2301A control.	Adjust GAIN, RESET, and ACTUATOR COMPENSATION as described in "Adjust for Stable Operation" and "Dynamic Adjustment" in Chapter 3.

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Symptom	Cause	Remedy
Prime mover will not stabilize at rated no load speed. The instability may occur at no load or it may vary with load. Control may be erratic. (cont.)	Speed setting controls.	If adjustment of external speed trim causes instability, check potentiometer with ohmmeter for erratic behavior (turn power off). Use non-lubricating electrical cleaner if necessary. If internal speed potentiometer is faulty, replace control.
	Improper linkage adjustment.	Make sure that actuator moves approximately 2/3 of its travel from no load to full load. Be sure linkage is linear on turbine, diesel, and fuel-injected prime movers. Be sure linkage is non-linear on carbureted prime movers. Refer to actuator manual for proper installation.
	Necessary external wires not properly shielded. Electrical noise, caused by wiring carrying an ac voltage, stray magnetic fields from transformers, etc., can be picked up by improperly shielded wire. Noise will cause instability if picked up by lines associated with the amplifier summing point such as external speed trim, paralleling lines, droop contact, magnetic pickup lines, and synchronizer input.	The following tests will isolate noise and interference. NOTICE Do not perform these tests in other than single-unit operating configuration. Jumper terminal 19 to terminal 16 (terminal 0 on high voltage controls), and remove wires to the Close for Rated contact. Where an external speed trim is used, jumper terminals 23 and 24, and remove wires to the potentiometer. WARNING Prime mover may overspeed if jumper is installed while running. Remove wires to terminals 10, 11, 12, 14, 25, and 26. Jumper 14 and 16. Remove the wires to the minimum-fuel contact at terminal 17. Verify that the switchgear frame, governor chassis, and prime mover have a common ground connection. Temporarily remove the battery-charger cables from the control battery system. If the prime-mover operation is significantly improved by the above modifications, replace the wiring one at a time to locate the source of the trouble. External wiring may require additional shielding or rerouting from high-current lines or components. (continued below)



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2301A LSSC w/Temperature or Process Limiting

Symptom	Cause	Remedy
Prime mover will not stabilize at rated no load speed. The instability may occur at no load or it may vary with load. Control may be erratic. (cont.)		(cont.) If the problem cannot be resolved by the above checks, it will be necessary to remove the 2301A control from the switchgear. Temporarily mount it next to the prime mover and connect only a battery, magnetic pickup, and actuator to the control (use a separate battery placed next to the prime mover). After starting the prime mover, place a small jumper wire across terminals 19 and 16 to cause the prime mover to accelerate to rated speed. If necessary, apply load to check stability. If stability occurs when the control is mounted next to the prime mover, return the control to the switchgear. Run new magnetic pickup, actuator, and battery power lines. Shield all wires to the control. Route all wires through conduit or an outer shield. Tie the outer shield to system ground at end opposite of the control.
	Prime mover may not be receiving fuel as called for by the actuator voltage.	Check actuator linkage to fuel controlling mechanism for any lost motion, binding, or excessive loading. Verify a steady fuel pressure of proper value. Check actuator per appropriate actuator manual.
	Prime mover not operating properly.	Prime mover may be causing speed variations. Control engine manually to determine if instability is in prime mover or governor control. Verify proper adjustment of fuel control linkage.
	Input voltage low.	Check supply voltage. It should be at least 18 Vdc on low voltage controls and 90 Vdc or 88 Vac on high voltage controls.
Speed-setting control does not regulate speed.	Faulty RATED SPEED or Speed Trim potentiometer.	Check by replacing Speed Trim with jumper and setting speed with main speed potentiometer.



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Symptom	Cause	Remedy
Prime mover does not share load with other units.	Prime mover not receiving fuel as called for by the governor.	If voltage to actuator is maximum (minimum for reverse-acting), visually determine if actuator shaft is at maximum position. If it is not, an actuator problem is indicated, or the linkage or fuel system is restricted.
	Unequal speed settings.	Be sure that speed settings of all units at no load are identical.
	Unequal load-gain voltages.	With the prime mover operating in single unit configuration, LOAD GAIN must be set at 6.0 Vdc. See "Load Gain Adjustment" in Chapter 3.
	Circuit breaker auxiliary contact or droop contact is open.	Check auxiliary circuit breaker and droop contacts. Check for 18 to 40 Vdc from terminal 14 to 15 on low voltage controls. NOTE <i>High voltage controls can only be measured from terminal 14 to 18 if the close to override failed speed signal contact is not closed.</i>
	Improper load-sensing phasing.	Perform phasing procedure in Chapter 3.
	Circulating currents between generators.	Refer to appropriate voltage regulator manual.
Prime mover does not maintain constant speed (isochronous).	Actuator.	If actuator has a ballhead backup, verify that its hydraulic governor section, speed setting, and speed droop adjustments are properly set (see the applicable governor manual).
	Prime mover.	If droop occurs near the full-load point only, it is possible the prime mover is not producing the power called for by the fuel control, or is being overloaded. Either is indicated if the fuel control is at maximum position.
Temperature limiter does not limit temperature.	Check thermocouple and associated wiring.	Replace thermocouple or repair or replace wires.
Process control does not limit process variable.	Check process transducer and associated wiring.	Replace process transducer or repair or replace wires.
Prime mover won't stabilize with load (when TEMP [or PROC] IN CONTROL LED is illuminated).	Temperature (or process) GAIN or RESET potentiometers incorrectly set.	Set temperature (or process) potentiometers (see Chapter 3, Operation and Adjustment).



Chapter 6. Product Support and Service Options

Product Support Options

If you are experiencing problems with the installation, or unsatisfactory performance of a Woodward product, the following options are available:

1. Consult the troubleshooting guide in the manual.
2. Contact the **OE Manufacturer or Packager** of your system.
3. Contact the **Woodward Business Partner** serving your area.
4. Contact Woodward technical assistance via email (EngineHelpDesk@Woodward.com) with detailed information on the product, application, and symptoms. Your email will be forwarded to an appropriate expert on the product and application to respond by telephone or return email.
5. If the issue cannot be resolved, you can select a further course of action to pursue based on the available services listed in this chapter.

OEM or Packager Support: Many Woodward controls and control devices are installed into the equipment system and programmed by an Original Equipment Manufacturer (OEM) or Equipment Packager at their factory. In some cases, the programming is password-protected by the OEM or packager, and they are the best source for product service and support. Warranty service for Woodward products shipped with an equipment system should also be handled through the OEM or Packager. Please review your equipment system documentation for details.

Woodward Business Partner Support: Woodward works with and supports a global network of independent business partners whose mission is to serve the users of Woodward controls, as described here:

- A **Full-Service Distributor** has the primary responsibility for sales, service, system integration solutions, technical desk support, and aftermarket marketing of standard Woodward products within a specific geographic area and market segment.
- An **Authorized Independent Service Facility (AISF)** provides authorized service that includes repairs, repair parts, and warranty service on Woodward's behalf. Service (not new unit sales) is an AISF's primary mission.
- A **Recognized Engine Retrofitter (RER)** is an independent company that does retrofits and upgrades on reciprocating gas engines and dual-fuel conversions, and can provide the full line of Woodward systems and components for the retrofits and overhauls, emission compliance upgrades, long term service contracts, emergency repairs, etc.

A current list of Woodward Business Partners is available at www.woodward.com/directory.

Product Service Options

Depending on the type of product, the following options for servicing Woodward products may be available through your local Full-Service Distributor or the OEM or Packager of the equipment system.

- Replacement/Exchange (24-hour service)
- Flat Rate Repair
- Flat Rate Remanufacture



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Replacement/Exchange: Replacement/Exchange is a premium program designed for the user who is in need of immediate service. It allows you to request and receive a like-new replacement unit in minimum time (usually within 24 hours of the request), providing a suitable unit is available at the time of the request, thereby minimizing costly downtime.

This option allows you to call your Full-Service Distributor in the event of an unexpected outage, or in advance of a scheduled outage, to request a replacement control unit. If the unit is available at the time of the call, it can usually be shipped out within 24 hours. You replace your field control unit with the like-new replacement and return the field unit to the Full-Service Distributor.

Flat Rate Repair: Flat Rate Repair is available for many of the standard mechanical products and some of the electronic products in the field. This program offers you repair service for your products with the advantage of knowing in advance what the cost will be.

Flat Rate Remanufacture: Flat Rate Remanufacture is very similar to the Flat Rate Repair option, with the exception that the unit will be returned to you in "like-new" condition. This option is applicable to mechanical products only.

Returning Equipment for Repair

If a control (or any part of an electronic control) is to be returned for repair, please contact your Full-Service Distributor in advance to obtain Return Authorization and shipping instructions.

When shipping the item(s), attach a tag with the following information:

- return number;
- name and location where the control is installed;
- name and phone number of contact person;
- complete Woodward part number(s) and serial number(s);
- description of the problem;
- instructions describing the desired type of repair.

Packing a Control

Use the following materials when returning a complete control:

- protective caps on any connectors;
- antistatic protective bags on all electronic modules;
- packing materials that will not damage the surface of the unit;
- at least 100 mm (4 inches) of tightly packed, industry-approved packing material;
- a packing carton with double walls;
- a strong tape around the outside of the carton for increased strength.

NOTICE

To prevent damage to electronic components caused by improper handling, read and observe the precautions in Woodward manual 82715, *Guide for Handling and Protection of Electronic Controls, Printed Circuit Boards, and Modules*.

Replacement Parts

When ordering replacement parts for controls, include the following information:

- the part number(s) (XXXX-XXXX) that is on the enclosure nameplate;
- the unit serial number, which is also on the nameplate.



Engineering Services

Woodward's Full-Service Distributors offer various Engineering Services for our products. For these services, you can contact the Distributor by telephone or by email.

- Technical Support
- Product Training
- Field Service

Technical Support is available from your equipment system supplier, your local Full-Service Distributor, or from many of Woodward's worldwide locations, depending upon the product and application. This service can assist you with technical questions or problem solving during the normal business hours of the Woodward location you contact.

Product Training is available as standard classes at many Distributor locations. Customized classes are also available, which can be tailored to your needs and held at one of our Distributor locations or at your site. This training, conducted by experienced personnel, will assure that you will be able to maintain system reliability and availability.

Field Service engineering on-site support is available, depending on the product and location, from one of our Full-Service Distributors. The field engineers are experienced both on Woodward products as well as on much of the non-Woodward equipment with which our products interface.

For information on these services, please contact one of the Full-Service Distributors listed at www.woodward.com/directory.

Contacting Woodward's Support Organization

For the name of your nearest Woodward Full-Service Distributor or service facility, please consult our worldwide directory published at www.woodward.com/directory.

You can also contact the Woodward Customer Service Department at one of the following Woodward facilities to obtain the address and phone number of the nearest facility at which you can obtain information and service.

Products Used In Electrical Power Systems

<u>Facility</u>	<u>Phone Number</u>
Brazil	+55 (19) 3708 4800
China	+86 (512) 6762 6727
Germany:	
Kempen	+49 (0) 21 52 14 51
Stuttgart	+49 (711) 78954-510
India	+91 (129) 4097100
Japan	+81 (43) 213-2191
Korea	+82 (51) 636-7080
Poland	+48 12 295 13 00
United States	+1 (970) 482-5811

Products Used In Engine Systems

<u>Facility</u>	<u>Phone Number</u>
Brazil	+55 (19) 3708 4800
China	+86 (512) 6762 6727
Germany	+49 (711) 78954-510
India	+91 (129) 4097100
Japan	+81 (43) 213-2191
Korea	+82 (51) 636-7080
The Netherlands	+31 (23) 5661111
United States	+1 (970) 482-5811

Products Used In Industrial Turbomachinery Systems

<u>Facility</u>	<u>Phone Number</u>
Brazil	+55 (19) 3708 4800
China	+86 (512) 6762 6727
India	+91 (129) 4097100
Japan	+81 (43) 213-2191
Korea	+82 (51) 636-7080
The Netherlands	+31 (23) 5661111
Poland	+48 12 295 13 00
United States	+1 (970) 482-5811

For the most current product support and contact information, please visit our website directory at www.woodward.com/directory.



Technical Assistance

If you need to contact technical assistance, you will need to provide the following information. Please write it down here before contacting the Engine OEM, the Packager, a Woodward Business Partner, or the Woodward factory:

General

Your Name _____

Site Location _____

Phone Number _____

Fax Number _____

Prime Mover Information

Manufacturer _____

Engine Model Number _____

Number of Cylinders _____

Type of Fuel (gas, gaseous, diesel,
dual-fuel, etc.) _____

Power Output Rating _____

Application (power generation, marine,
etc.) _____

Control/Governor Information

Control/Governor #1

Woodward Part Number & Rev. Letter _____

Control Description or Governor Type _____

Serial Number _____

Control/Governor #2

Woodward Part Number & Rev. Letter _____

Control Description or Governor Type _____

Serial Number _____

Control/Governor #3

Woodward Part Number & Rev. Letter _____

Control Description or Governor Type _____

Serial Number _____

Symptoms

Description _____

If you have an electronic or programmable control, please have the adjustment setting positions or the menu settings written down and with you at the time of the call.



We appreciate your comments about the content of our publications.

Send comments to: icinfo@woodward.com

Please reference publication **82386B**.



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Email and Website—www.woodward.com

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as well as authorized distributors and other authorized service and sales facilities throughout the world.

Complete address / phone / fax / email information for all locations is available on our website.



11. Power House Allen Bradley BOP PLC Tags and Descriptions

CSV-Import-Export

Date = Fri Aug 29 10:32:50 2014

Version = RSLogix 5000 v15.02

Owner = Fred Peikin

Company = Microsoft

NAME	DESCRIPTION
EA:1:C	
EA:1:I	
EA:4:C	
EA:4:I	
EA:5:C	
EA:5:I	
EA:6:C	
EA:6:I	
EA:6:O	
EA:9:C	
EA:9:I	
EA:9:O	
EA:I	
EA:O	
DA:10:C	
DA:10:I	
DA:10:O	
DA:11:C	
DA:11:I	
DA:11:O	
DA:1:C	
DA:1:I	
DA:2:C	
DA:2:I	
DA:3:C	
DA:3:I	
DA:4:C	
DA:4:I	
DA:5:C	
DA:5:I	
DA:8:C	
DA:8:I	
DA:8:O	
DA:9:C	
DA:9:I	
DA:9:O	
DA:I	
DA:O	
CA:10:C	
CA:10:I	

NAME	DESCRIPTION
CA:10:O	
CA:11:C	
CA:11:I	
CA:11:O	
CA:12:C	
CA:12:I	
CA:12:O	
CA:1:C	
CA:1:I	
CA:1:O	
CA:2:C	
CA:2:I	
CA:3:C	
CA:3:I	
CA:4:C	
CA:4:I	
CA:5:C	
CA:5:I	
CA:6:C	
CA:6:I	
CA:8:C	
CA:8:I	
CA:9:C	
CA:9:I	
CA:9:O	
CA:I	
CA:O	
AA_TOGGLE	
AC_1_AUTO_HMI	Air Comp #1
AC_1_AUTO_STOP	Air Comp #1
AC_1_AUTO_STRT	
AC_1_AVAIL	Air Comp #1
AC_1_KW_EVER_TOTAL	
AC_1_PRIORITY	
AC_1_RUN_HRS_EVER	
AC_1_START	Air Comp #1
AC_1_STOP	Air Comp #1
AC_1_STOP_HMI	Air Comp #1
AC_1_STOP_TIMER	Air Comp #1
AC_1_STRT_HMI	STRT from HMI
AC_1_STRT_TIMER	Air Comp #1
AC_1_TRIP	Air Comp #1 TRIP
AC_1_TRIP_RESET	
AC_1_TRIP_TIMER	Air Comp #1
AC_1_Vlv_MisMatch	AC #1 Cooling Water Valve Mismatch
AC_1_Vlv_MM_1	AC #1 Vlv MisMatch

NAME	DESCRIPTION
AC_1_Vlv_MM_2	AC #1 Vlv MisMatch Timer 2
AC_1_Vlv_MM_3	AC #1 Vlv MisMatch Timer 3
AC_2_AUTO_HMI	
AC_2_AUTO_STOP	
AC_2_AUTO_STRT	
AC_2_AVAIL	
AC_2_KW_EVER_TOTAL	
AC_2_PRIORITY	
AC_2_RUN_HRS_EVER	
AC_2_START	
AC_2_STOP	
AC_2_STOP_HMI	
AC_2_STOP_TIMER	
AC_2_STRT_HMI	
AC_2_STRT_TIMER	
AC_2_TRIP	
AC_2_TRIP_RESET	
AC_2_TRIP_TIMER	
AC_2_Vlv_MisMatch	
AC_2_Vlv_MM_1	
AC_2_Vlv_MM_2	
AC_2_Vlv_MM_3	
AC_3_AUTO_HMI	
AC_3_AUTO_STOP	
AC_3_AUTO_STRT	
AC_3_AVAIL	
AC_3_KW_EVER_TOTAL	
AC_3_PRIORITY	
AC_3_RUN_HRS_EVER	
AC_3_START	
AC_3_STOP	
AC_3_STOP_HMI	
AC_3_STOP_TIMER	
AC_3_STRT_HMI	
AC_3_STRT_TIMER	
AC_3_TRIP	
AC_3_TRIP_RESET	
AC_3_TRIP_TIMER	
AC_3_Vlv_MisMatch	
AC_3_Vlv_MM_1	
AC_3_Vlv_MM_2	
AC_3_Vlv_MM_3	
AC_4_AUTO_HMI	
AC_4_AUTO_STOP	
AC_4_AUTO_STRT	
AC_4_AVAIL	

NAME	DESCRIPTION
AC_4_KW_EVER_TOTAL	
AC_4_PRIORITY	
AC_4_RUN_HRS_EVER	
AC_4_START	
AC_4_STOP	
AC_4_STOP_HMI	
AC_4_STOP_TIMER	
AC_4_STRT_HMI	
AC_4_STRT_TIMER	
AC_4_TRIP	
AC_4_TRIP_RESET	
AC_4_TRIP_TIMER	
AC_4_Vlv_MisMatch	
AC_4_Vlv_MM_1	
AC_4_Vlv_MM_2	
AC_4_Vlv_MM_3	
AC_5_AUTO_HMI	
AC_5_AUTO_STOP	
AC_5_AUTO_STRT	
AC_5_AVAIL	
AC_5_FULL_LOAD	
AC_5_KW_EVER_TOTAL	
AC_5_LOAD	
AC_5_LOADED	Loaded Status MB
AC_5_LOADED_MB	
AC_5_LOADING	
AC_5_LOAD_HMI	
AC_5_LOAD_TMR	
AC_5_MAX_LOAD	
AC_5_MIN_LOAD	
AC_5_NOT_READY	
AC_5_READY	
AC_5_RUN_HRS_EVER	
AC_5_START	
AC_5_STOP	
AC_5_STOP_HMI	
AC_5_STOP_TIMER	
AC_5_STRT_HMI	
AC_5_STRT_TIMER	
AC_5_TRIP	
AC_5_TRIP_RESET	
AC_5_TRIP_TIMER	
AC_5_UNLOAD	
AC_5_UNLOADED	
AC_5_UNLOADED_DLY	
AC_5_UNLOADED_MB	Unloaded Status MB

NAME	DESCRIPTION
AC_5_UNLOAD_HMI	
AC_5_UNLOAD_TIMER	
AC_5_UNLOAD_TMR	
AC_5_Vlv_MisMatch	
AC_5_Vlv_MM_1	
AC_5_Vlv_MM_2	
AC_5_Vlv_MM_3	
AC_6_AUTO_HMI	
AC_6_AUTO_STOP	
AC_6_AUTO_STRT	
AC_6_AVAIL	
AC_6_Kwh	
AC_6_KWh_Calc	
AC_6_RUN_HRS_EVER	
AC_6_START	
AC_6_STOP	
AC_6_STOP_HMI	
AC_6_STOP_TIMER	
AC_6_STRT_HMI	
AC_6_STRT_TIMER	
AC_6_TRIP	
AC_6_TRIP_RESET	
AC_6_TRIP_TIMER	
AC_6_Vlv_MisMatch	
AC_6_Vlv_MM_1	
AC_6_Vlv_MM_2	
AC_6_Vlv_MM_3	
AC_Centec_SP_Read	
AC_Centec_SP_Write	
AC_Joy_SP_Read	
AC_Joy_SP_Write	
AC_Nirvana_SP_Read	
AC_Nirvana_SP_Write	
AC_Write_Centec_SP_HMI	
AC_Write_Joy_SP_HMI	Write new SP Value to JOY Comps
AC_Write_Nirvana_SP_HMI	
AHU1_AUTO_STOP	AHU-1 AUTO STOP
AHU1_AUTO_STRT	AHU-1 AUTO START
AHU2_AUTO_STOP	AHU-2 AUTO STOP
AHU2_AUTO_STRT	AHU-2 AUTO START
AHU_1_AUTO_HMI	AHU-1 AUTO FROM HMI
AHU_1_AVAIL	AHU-1 AVAILABLE FROM HMI
AHU_1_STOP	AHU-1 STOP BIT
AHU_1_STOP_HMI	AHU-1 STOP FROM HMI
AHU_1_STOP_TIMER	AHU 1 STOP PULSE TIMER
AHU_1_STRT_F_HMI	AHU-1 FAST START FROM HMI

NAME	DESCRIPTION
AHU_1_STRT_S_HMI	AHU-1 SLOW START FROM HMI
AHU_1_TRIP	AHU-1 TRIPPED
AHU_1_TRIP_RESET	AHU-1 TRIP RESET FROM HMI
AHU_2_AUTO_HMI	AHU-2 AUTO FROM HMI
AHU_2_AVAIL	AHU-2 AVAILABLE FROM HMI
AHU_2_STOP	AHU-2 STOP BIT
AHU_2_STOP_HMI	AHU-2 STOP FROM HMI
AHU_2_STOP_TIMER	AHU 2 STOP PULSE TIMER
AHU_2_STRT_F_HMI	AHU-2 FAST START FROM HMI
AHU_2_STRT_S_HMI	AHU-2 SLOW START FROM HMI
AHU_2_TRIP	AHU-2 TRIPPED
AHU_2_TRIP_RESET	AHU-2 TRIP RESET FROM HMI
AHU_2_TRIP_TIMER	AHU-2 TRIP TIMER
AHU_TRIP_TIMER	AHU-1 TRIP TIMER
AIR_COMP_MODE	
AIR_FREEZE_SWTCH_DEC	
AIR_FREEZE_SWTCH_INC	
AIR_HDR_LOW	Air Header Low Press
AIR_HDR_LOW_SP	HDR_ALM_SetPoint
AIR_HDR_SP_M3	3 PSI Below Sys SP
AIR_HDR_SP_M5	5 PSI Below Sys SP
AIR_HIGH_SWTCH_DEC	
AIR_HIGH_SWTCH_INC	
AIR_HIHI_SWTCH_DEC	
AIR_HIHI_SWTCH_INC	
Air_Joy_SP_W_Act	HMI Actively writing to SetPoint
Air_Joy_SP_x	
AIR_LOLO_SWTCH_INC	
AIR_LOW_SWTCH_DEC	
AIR_LOW_SWTCH_INC	
AIR_MED_SWTCH_DEC	
AIR_MED_SWTCH_INC	
AIR_MODE_AUTO	
Air_Mode_Auto_HMI	
AIR_MODE_AUTO_TOGGLE	
AIR_MODE_FREEZE	Air Comp Mode\$NFreezeFlow
Air_Mode_Freeze_HMI	HMI Select\$NFreeze Flow Mode
AIR_MODE_HIGH	Air Comp Mode\$NHigh Flow
Air_Mode_High_HMI	HMI Select\$NHigh Flow Mode
AIR_MODE_HIHI	Air Comp Mode\$NHigh High Flow
Air_Mode_HiHi_HMI	HMI Select\$NHigh High Flow Mode
AIR_MODE_INT	
Air_Mode_LOLO	Air Comp Mode\$NLoLo Flow
Air_Mode_LoLo_HMI	HMI Select\$NLoLo Flow Mode
AIR_MODE_LOW	Air Comp Mode\$NLow Flow
Air_Mode_Low_HMI	HMI Select\$NLow Flow Mode

NAME	DESCRIPTION
AIR_MODE_MED	Air Comp Mode\$NMed Flow
Air_Mode_Med_HMI	HMI Select\$NMed Flow Mode
AIR_MODE_SWITCH_DLY	
AIR_SYS_SP	
AIR_SYS_SP_Array	
AIR_SYS_SP_Array	Joy SetPoint\$N(int * 10)
AIR_SYS_SP_Array	Centec SetPoint (Float)
AIR_SYS_SP_Array	Centec SetPoint (Float)
AIR_SYS_SP_Array	Nirvana SetPoint (Int)
ALARM_HORN	ALARM HORN OUTPUT
always_false	
AUTO_MODE_SWTCH_DLY	
AUTO_STOP_CENTEC	
AUTO_STOP_NIRVANA	
AUTO_STRT_1st_JOY	
AUTO_STRT_2nd_JOY	
AUTO_STRT_3rd_JOY	
AUTO_STRT_4th_JOY	
AUTO_STRT_AC_6	
AUTO_STRT_CENTEC	
B3BSFR	BOILER 3 RESERVE STEAM
B4BSFR	BOILER 4 RESERVE STEAM
B4_COMM_COUNTER	
B4_COMM_TIMER	
BFP1_RUN_EVER_TOTAL	
BFP1_RUN_MONTH_TOT	BOILER FEED PUMP 1 RUNTIME MONTHLY TOTAL
BFP1_RUN_YEAR_TOTAL	BOILER FEED PUMP 1 RUNTIME YEARLY TOTAL
BFP2_RUN_EVER_TOTAL	
BFP2_RUN_MONTH_TOT	BOILER FEED PUMP 2 RUNTIME MONTHLY TOTAL
BFP2_RUN_YEAR_TOTAL	BOILER FEED PUMP 2 RUNTIME YEARLY TOTAL
BFP3_RUN_EVER_TOTAL	
BFP3_RUN_MONTH_TOT	BOILER FEED PUMP 3 RUNTIME MONTHLY TOTAL
BFP3_RUN_YEAR_TOTAL	BOILER FEED PUMP 3 RUNTIME YEARLY TOTAL
BFP4_RUN_EVER_TOTAL	
BFP4_RUN_MONTH_TOT	BOILER FEED PUMP 4 RUNTIME MONTHLY TOTAL
BFP4_RUN_YEAR_TOTAL	BOILER FEED PUMP 4 RUNTIME YEARLY TOTAL
BFP_1_AUTO_HMI	
BFP_1_AUTO_STRT	
BFP_1_AVAIL	
BFP_1_NAF	
BFP_1_STOP_HMI	
BFP_1_STRT_HMI	
BFP_1_TRIP	
BFP_1_TRIP_RESET	
BFP_1_TRIP_TIMER	
BFP_2_AUTO_HMI	

NAME	DESCRIPTION
BFP_2_AUTO_STRT	
BFP_2_AVAIL	
BFP_2_NAF	
BFP_2_STOP_HMI	
BFP_2_STRT_HMI	
BFP_2_TRIP	
BFP_2_TRIP_RESET	
BFP_2_TRIP_TIMER	
BFP_3_AUTO_HMI	
BFP_3_AUTO_STRT	
BFP_3_AVAIL	
BFP_3_NAF	
BFP_3_STOP_HMI	
BFP_3_STRT_HMI	
BFP_3_TRIP	
BFP_3_TRIP_RESET	
BFP_3_TRIP_TIMER	
BFP_4_AUTO_HMI	
BFP_4_AVAIL	
BFP_4_NAF	
BFP_4_START_PROMPT	
BFP_4_STOP_HMI	
BFP_4_STRT_HMI	
BFP_4_TRIP	
BFP_4_TRIP_RESET	
Bill	
BLR3BM	BOILER 3 BOILER MASTER DEMAND
BLR3BM_SOFT	BOILER 3 DEMAND VIA ETHERNET
BLR3DMD	BOILER 3 MAN OUTPUT FROM HMI
BLR3FW_FLOW	
BLR3L_R	BOILER 3 IN REMOTE
BLR3_1_COMM_ERR	BLR3_1 COMM LOSS
BLR3_2_COMM_ERR	BLR3_2 COMM LOSS
BLR3_3_COMM_ERR	BLR3_3 COMM LOSS
BLR3_4_COMM_ERR	BLR3_4 COMM LOSS
BLR3_5_COMM_ERR	BLR3_5 COMM LOSS
BLR3_COMM_COUNTER	
BLR3_COMM_TIMER	
BLR3_COST_OF_STEAM	BOILER 3 COST OF STEAM (4?LB)
BLR3_COST_OF_STEAM_GAS	BOILER 3 COST OF STEAM GAS
BLR3_COST_OF_STEAM_OIL	BOILER 3 COST OF STEAM OIL
BLR3_FEEDWATER_FLOW	BOILER 3 FEEDWATER FLOW KPPH
BLR3_FIRE_EVER_TOTAL	
BLR3_FIRE_GAS_EVER_TOTAL	
BLR3_FIRE_OIL_EVER_TOTAL	
BLR3_FWFLOW_EVER_TOTAL	

NAME	DESCRIPTION
BLR3_FWFLOW_MONTH_TOT	BOILER 3 FEEDWATER FLOW TOTALS MONTHLY TOTAL
BLR3_FWFLOW_YEAR_TOTAL	BOILER 3 FEEDWATER FLOW TOTALS YEARLY TOTAL
BLR3_FW_FGEN	
BLR3_FW_X	
BLR3_FW_Y	
BLR3_GASFLOW_EVER_TOTAL	
BLR3_GASFLOW_MONTH_TOT	
BLR3_GASFLOW_YEAR_TOTAL	
BLR3_GAS_FLOW_KSCFH	
BLR3_GAS_FLOW_KSCFM	BOILER 3 GAS FLOW (KSCFM)
BLR3_OILFLOW_EVER_TOTAL	
BLR3_OILFLOW_MONTH_TOT	
BLR3_OILFLOW_YEAR_TOTAL	
BLR3_OIL_FLOW_GPM	
BLR3_ON	BOILER 3 ON
BLR3_ON_CNTL	BOILER 3 RUNNING AND IN REMOTE
BLR3_PLC_COMM	BLR3 COMMS GOOD
BLR3_PLC_ERR	BLR 3 COMMS ERROR NO DELAY
BLR3_READS2_INT	
BLR3_READS4_INT	
BLR3_READS_INT	BOILER 3 IN REMOTE FROM LOCAL PLC
BLR3_READS_INT	BOILER 3 READS
BLR3_SLC_READ	
BLR3_STEAM_FLOW	BOILER 3 STEAM FLOW\$NKPPH
BLR3_STMFLOW_EVER_TOTAL	
BLR3_STMFLOW_MONTH_TOT	BOILER 3 STEAM FLOW TOTALS MONTHLY TOTAL
BLR3_STMFLOW_YEAR_TOTAL	BOILER 3 STEAM FLOW TOTALS YEARLY TOTAL
BLR3_WRITES_INT	
BLR4BM	BOILER 4 BOILER MASTER DEMAND
BLR4BM_SOFT	BOILER 4 DEMAND VIA ETHERNET
BLR4DMD	BOILER 4 DEMAND VIA ETHERNET
BLR4FW_FLOW	
BLR4L_R	BOILER 4 IN REMOTE FROM LOCAL PLC
BLR4_1_COMM_ERR	BLR4_1 COMM LOSS
BLR4_2_COMM_ERR	BLR4_2 COMM LOSS
BLR4_3_COMM_ERR	BLR4_3 COMM LOSS
BLR4_4_COMM_ERR	BLR4_4 COMM LOSS
BLR4_5_COMM_ERR	BLR4_5 COMM LOSS
BLR4_COST_OF_STEAM	BOILER 4 COST OF STEAM (\$\$/LB)
BLR4_COST_OF_STEAM_GAS	BOILER 4 COST OF STEAM GAS
BLR4_COST_OF_STEAM_OIL	BOILER 4 COST OF STEAM OIL
BLR4_FEEDWATER_FLOW	BOILER 4 FEEDWATER FLOW KPPH
BLR4_FIRE_EVER_TOTAL	
BLR4_FIRE_GAS_EVER_TOTAL	
BLR4_FIRE_OIL_EVER_TOTAL	
BLR4_FIRE_RATE	

NAME	DESCRIPTION
BLR4_FWFLOW_EVER_TOTAL	
BLR4_FWFLOW_MONTH_TOT	BOILER 4 FEEDWATER FLOW MONTHLY TOTAL
BLR4_FWFLOW_YEAR_TOTAL	BOILER 4 FEEDWATER FLOW YEARLY TOTAL
BLR4_FW_FGEN	
BLR4_GASFLOW_EVER_TOTAL	
BLR4_GASFLOW_MONTH_TOT	
BLR4_GASFLOW_YEAR_TOTAL	
BLR4_GAS_FLOW_KSCFH	
BLR4_GAS_FLOW_KSCFM	BOILER 4 GAS FLOW (KSCFM)
BLR4_OILFLOW_EVER_TOTAL	
BLR4_OILFLOW_MONTH_TOT	
BLR4_OILFLOW_YEAR_TOTAL	
BLR4_OIL_FLOW_GPM	
BLR4_ON	BOILER 4 ON
BLR4_ON_CNTRL	BOILER 4 RUNNING AND IN REMOTE
BLR4_PLC_COMM	BLR4 COMMS GOOD
BLR4_PLC_ERR	BOILER 4 COMM ERROR NO DELAY
BLR4_READS2_INT	
BLR4_READS4_INT	
BLR4_READS_INT	
BLR4_SLC_READ	
BLR4_STEAM_FLOW	BOILER 4 STEAM FLOW KPPH
BLR4_STMFLOW_EVER_TOTAL	
BLR4_STMFLOW_MONTH_TOT	BOILER 4 STEAM FLOW MONTHLY TOTAL
BLR4_STMFLOW_YEAR_TOTAL	BOILER 4 STEAM FLOW YEARLY TOTAL
BLR4_WRITES_INT	
BLR_3_AUTO	BOILER 3 IN AUTO\$NFROM HMI
BLR_3_BIAS	BOILER 3 BIAS FROM HMI
BLR_4_AUTO	BOILER 4 IN AUTO FROM HMI
BLR_4_BIAS	BOILER 4 BIAS FROM HMI
BOILER_3_OIL_SEL	BOILER 3 OIL SELECTED
BOILER_4_OIL_SEL	
CIK_200_3	
CIK_200_4	
CmdErrData	
CmdMsgData	
ColdBoot	
ColdBoot_AC	
COOL_TWR_MONTH_TOT	
COOL_TWR_YEAR_TOTAL	
COST_CMP_POWER	COST OF CMP POWER
COST_CMP_POWER_NC	COST OF CMP POWER WITH NO COGENERATION
COST_OF_PEAK_DMD	COST OF PEAK DEMAND
COST_OF_POWER	COST OF POWER\$N\$/kWh
COST_OF_SHOULDER_DMD	COST OF SHOULDER DEMAND
COST_PNS_PROD_PWR	COST OF PNS PRODUCED POWER \$N\$/HR

NAME	DESCRIPTION
COST_PNS_PROD_PWR_KW	COST OF PNS PRODUCED\$NPOWER \$\$/KWhr
COUNTER	
CP1_RUN_EVER_TOTAL	
CP1_RUN_MONTH_TOT	CONDENSATE PUMP 1 RUNTIME MONTHLY TOTAL
CP1_RUN_YEAR_TOTAL	CONDENSATE PUMP 1 RUNTIME YEARLY TOTAL
CP2_RUN_EVER_TOTAL	
CP2_RUN_MONTH_TOT	CONDENSATE PUMP 2 RUNTIME MONTHLY TOTAL
CP2_RUN_YEAR_TOTAL	CONDENSATE PUMP 2 RUNTIME YEARLY TOTAL
CP_1_AUTO_HMI	
CP_1_AVAIL	
CP_1_FAIL_TIMER	
CP_1_LEAD	
CP_1_LEAD_PMP	
CP_1_STOP_AUTO	
CP_1_STOP_HMI	
CP_1_STRT_AUTO	
CP_1_STRT_EN	
CP_1_STRT_HMI	
CP_1_TRIP	
CP_1_TRIP_RESET	
CP_1_TRIP_TIMER	
CP_2_AUTO_HMI	
CP_2_AVAIL	
CP_2_LEAD	
CP_2_LEAD_PMP	
CP_2_STOP_HMI	
CP_2_STRT_HMI	
CP_2_TRIP	
CP_2_TRIP_RESET	
CP_2_TRIP_TIMER	CONDENSATE PUMP 2 TRIP TIMER
CP_LEAD_PMP	
CS_220_3	BOILER 3 CONDUCTIVITY
CS_220_3_BQ	BOILER 3 CONDUCTIVITY BQ
CS_220_4	BOILER 4 CONDUCTIVITY
CS_220_4_BQ	BOILER 4 CONDUCTIVITY BQ
CS_400_1	COOLING WATER CONDUCTIVITY
CS_400_1_BQ	COOLING WATER CONDUCTIVITY BQ
CT1_COST_OF_POWER	CT1 COST OF POWER\$N(\$\$/HR)
CT1_DB1_ON	CTG1 RUNNING WITH DUCT BURNERS
CT1_FUEL	CT1 FUEL (Dth/hr)
CT1_FUEL_1	CT1 FUEL PART 1 (Dths/hr)
CT1_FUEL_2	CT1 FUEL PART 2
CT1_VFD_DMD	
CT2_COST_OF_POWER	CT2 COST OF POWER\$N(\$\$/hr
CT2_DB2_ON	CTG2 RUNNING WITH DUCT BURNERS
CT2_FUEL	CT2_FUEL Dths/hr

NAME	DESCRIPTION
CT2_FUEL_PART1	
CT2_FUEL_PART2	
CT2_VFD_DMD	
CT3_VFD_DMD	
CTF1_ALARM	
CTF1_CURRENT_RUN	
CTF1_DELAY	
CTF1_DRIVE_TEMP	CTF1 VFD Drive Temp (Deg f)
CTF1_EVER_TOTAL	
CTF1_FAULT	
CTF1_HZ	
CTF1_MONTH_TOT	
CTF1_OFF_TIMER	
CTF1_R	
CTF1_REMOTE	
CTF1_REV_TIMER	
CTF1_SEQ_STOP_TIMER	
CTF1_SEQ_STRT_TIMER	
CTF1_SF	
CTF1_SR	
CTF1_YEAR_TOTAL	
CTF2_ALARM	
CTF2_CURRENT_RUN	
CTF2_DELAY	
CTF2_DRIVE_TEMP	CTF2 VFD Drive Temp (Deg f)
CTF2_EVER_TOTAL	
CTF2_FAULT	
CTF2_HZ	
CTF2_MONTH_TOT	
CTF2_OFF_TIMER	
CTF2_R	
CTF2_REMOTE	
CTF2_REV_TIMER	
CTF2_SEQ_STOP_TIMER	
CTF2_SEQ_STRT_TIMER	
CTF2_SF	
CTF2_SR	
CTF2_YEAR_TOTAL	
CTF3_ALARM	
CTF3_CURRENT_RUN	
CTF3_DELAY	
CTF3_DRIVE_TEMP	CTF3 VFD Drive Temp (Deg f)
CTF3_EVER_TOTAL	
CTF3_FAULT	
CTF3_HZ	
CTF3_MONTH_TOT	

NAME	DESCRIPTION
CTF3_OFF_TIMER	
CTF3_R	
CTF3_REMOTE	
CTF3_REV_TIMER	
CTF3_SEQ_STOP_TIMER	
CTF3_SEQ_STRT_TIMER	
CTF3_SF	
CTF3_SR	
CTF3_YEAR_TOTAL	
CTF_1_AVAIL	
CTF_1_SEQ_HMI	
CTF_1_STOP	
CTF_1_STOP_HMI	
CTF_1_STRTR_HMI	
CTF_1_STRT_HMI	
CTF_1_TRIP	
CTF_1_TRIP_RESET	
CTF_1_TRIP_TIMER	
CTF_2_AVAIL	
CTF_2_SEQ_HMI	
CTF_2_STOP	
CTF_2_STOP_HMI	
CTF_2_STRTR_HMI	
CTF_2_STRT_HMI	
CTF_2_TRIP	
CTF_2_TRIP_RESET	
CTF_2_TRIP_TIMER	
CTF_3_AVAIL	
CTF_3_SEQ_HMI	
CTF_3_STOP	
CTF_3_STOP_HMI	
CTF_3_STRTR_HMI	
CTF_3_STRT_HMI	
CTF_3_TRIP	
CTF_3_TRIP_RESET	
CTF_3_TRIP_TIMER	
CTF_SEQ	
CTF_SEQ_123	
CTF_SEQ_132	
CTF_SEQ_1_DMD	
CTF_SEQ_1_X	
CTF_SEQ_1_Y	
CTF_SEQ_213	
CTF_SEQ_231	
CTF_SEQ_2_DMD	
CTF_SEQ_2_X	

NAME	DESCRIPTION
CTF_SEQ_2_Y	
CTF_SEQ_312	
CTF_SEQ_321	
CTF_SEQ_3_DMD	
CTF_SEQ_3_X	
CTF_SEQ_3_Y	
CTF_SEQ_FGEN_1	
CTF_SEQ_FGEN_2	
CTF_SEQ_FGEN_3	
CTF_SEQ_TRSW	
CTG1DMD	CTG1 MANUAL OUTPUT FROM HMI
CTG1_1_COMM_ERR	CTG1_1 COMM LOSS
CTG1_2_COMM_ERR	CTG1_2 COMM LOSS
CTG1_3_COMM_ERR	CTG1_3 COMM LOSS
CTG1_GASFLOW_EVER_TOTAL	
CTG1_GASFLOW_MONTH_TOT	
CTG1_GASFLOW_YEAR_TOTAL	
CTG1_GAS_FLOW_KSCFH	CTG1 GAS FLOW (KSCFH)
CTG1_GAS_FLOW_KSCFM	CTG1 GAS FLOW (KSCFM)
CTG1_GAS_FLOW_PPH	
CTG1_GAS_FLOW_RAW	
CTG1_KW	
CTG1_KWH_EVER_TOTAL	
CTG1_KWH_MONTH_TOT	
CTG1_KWH_YEAR_TOTAL	
CTG1_KW_INT	
CTG1_ON	
CTG1_PLC_COMM	CTG1 COMMS GOOD
CTG1_REM	
CTG1_REMOTE	
CTG1_RUN_EVER_TOTAL	
CTG1_RUN_MONTH_TOT	
CTG1_RUN_YEAR_TOTAL	
CTG1_SPEED	
CTG1_SP_SCALED	
CTG2DMD	CTG2 MANUAL OUTPUT FROM HMI
CTG2_1_COMM_ERR	CTG2_1 COMM LOSS
CTG2_2_COMM_ERR	CTG2_2 COMM LOSS
CTG2_GASFLOW_EVER_TOTAL	
CTG2_GASFLOW_MONTH_TOT	
CTG2_GASFLOW_YEAR_TOTAL	
CTG2_GAS_FLOW_KSCFH	CTG2 GAS FLOW (KSCFH)
CTG2_GAS_FLOW_KSCFM	CTG2 GAS FLOW (KSCFM)
CTG2_GAS_FLOW_KSCFMA	
CTG2_GAS_FLOW_PPH	
CTG2_KW	

NAME	DESCRIPTION
CTG2_KWH_EVER_TOTAL	
CTG2_KWH_MONTH_TOT	
CTG2_KWH_YEAR_TOTAL	
CTG2_OILFLOW_EVER_TOTAL	
CTG2_OILFLOW_MONTH_TOT	
CTG2_OILFLOW_YEAR_TOTAL	
CTG2_OIL_FLOW_GPM	CTG2 OIL FLOW (GPM)
CTG2_OIL_FLOW_PPH	
CTG2_ON	
CTG2_ON_GAS	CTG2 ON GAS
CTG2_ON_OIL	CTG2 ON OIL
CTG2_PLC_COMM	CTG2 COMMS GOOD
CTG2_READS_DINT	
CTG2_READS_INT	
CTG2_READS_REAL	
CTG2_RUN_EVER_TOTAL	
CTG2_RUN_GAS_EVER_TOTAL	
CTG2_RUN_MONTH_TOT	
CTG2_RUN_OIL_EVER_TOTAL	
CTG2_RUN_YEAR_TOTAL	
CTG2_TOGGLE	
CTG2_TOTAL_KW	CTG2 TOTAL KW FROM CTG2
CTGS_MAX	LOAD CTG\$'S FOR MAXIMUM UTILITY IMPORT
CTGS_MIN	LOAD CTG\$'S FOR MINIMUM UTILITY IMPORT
CTG_2_LIQ_FUEL_SEL	
CURR_DEL_CHARGE_NW	CURRENT DELIVERY CHARGE (NON WINTER)
CUR_DEL_CHARGE	CURRENT DELIVERY CHARGE (WINTER)
CV200_3A_FC_TIMER	
CV200_3A_FO_TIMER	
CVP_100_1	GT_1 STEAM VENT POSITION FEEDBACK
CVP_100_1_BQ	GT_1 STEAM VENT POSITION FEEDBACK BQ
CVP_100_2	NORTH HEADER STEAM VENT VALVE POSITION FEEDBACK
CVP_100_2_BQ	NORTH HEADER STEAM VENT VALVE POSITION FEEDBACK BQ
CVP_200_3A	DEAERATOR 1 OVERFLOW VALVE OPEN
CVP_200_3B	DEAERATOR 1 OVERFLOW VALVE CLOSED
CVP_210_1	DEAERATOR No.1 CONDENSATE VALVE POSITON FEEDBACK
CVP_210_1_BQ	DEAERATOR No.1 CONDENSATE VALVE POSITON FEEDBACK BQ
CVP_220_3	BOILER 3 CONTINUOUS BLOWDOWN VALVE POSITION FEEDBACK
CVP_220_3_BQ	BOILER 3 CONTINUOUS BLOWDOWN VALVE POSITION FEEDBACK BQ
CVP_220_4	BOILER 4 CONTINUOUS BLOWDOWN VALVE POSITION FEEDBACK
CVP_220_4_BQ	BOILER 4 CONTINUOUS BLOWDOWN VALVE POSITION FEEDBACK BQ
CVP_230_1	DEAERATOR No.1 MAKE-UP VALVE POSITON FEEDBACK
CVP_230_1_BQ	DEAERATOR No.1 MAKE-UP VALVE POSITON FEEDBACK BQ
CVP_400_1	COOLING TOWER BYPASS VALVE POSITON FEEDBACK
CVP_400_1_BQ	COOLING TOWER BYPASS VALVE POSITON FEEDBACK BQ
CVP_400_1_DEV	

NAME	DESCRIPTION
CVP_400_2	COOLING TOWER MAKEUP VALVE OPENED
CV_100_1	GT_1 STEAM VENT VALVE
CV_100_1_DEV	
CV_100_1_DEV_ALM	
CV_100_2	NORTH HEADER STEAM VENT VALVE
CV_100_2_DEV	
CV_100_2_DEV_ALM	
CV_200_1	DEAERATOR No.1 CONDENSATE VALVE
CV_200_2	DEAERATOR No.1 MAKE-UP VALVE
CV_200_3A	
CV_200_3A_AUTO	
CV_200_3A_CLSE	
CV_200_3A_OPEN	
CV_200_LATCH	
CV_220_3	BOILER 3 CONTINUOUS BLOWDOWN VALVE
CV_220_4	BOILER 4 CONTINUOUS BLOWDOWN VALVE
CV_400_1	COOLING TOWER BYPASS VALVE
CV_400_2	
CV_400_3	
CV_400_3_AUTO_HMI	
CV_400_3_CLOSE_HMI	
CV_400_3_OPEN_HMI	
CWP1_ALARM	
CWP1_CURRENT_RUN	
CWP1_DRIVE_TEMP	CWP1 VFD Drive Temp (Deg f)
CWP1_FAULT	
CWP1_MAVE	
CWP1_MAVE_STOR	
CWP1_MONTH_TOT	
CWP1_REMOTE	
CWP1_RUN_EVER_TOTAL	
CWP1_VFD	
CWP1_YEAR_TOTAL	
CWP2_ALARM	
CWP2_CURRENT_RUN	
CWP2_DRIVE_TEMP	CWP2 VFD Drive Temp (Deg f)
CWP2_FAULT	
CWP2_MAVE	
CWP2_MAVE_STOR	
CWP2_MONTH_TOT	
CWP2_REMOTE	
CWP2_RUN_EVER_TOTAL	
CWP2_VFD	
CWP2_YEAR_TOTAL	
CWP_1_AUTO_HMI	
CWP_1_AVAIL	

NAME	DESCRIPTION
CWP_1_LEAD	
CWP_1_LEAD_PMP	
CWP_1_RUN	
CWP_1_STOP	
CWP_1_STOP_HMI	
CWP_1_STRT	
CWP_1_STRT_HMI	
CWP_1_TRIP	
CWP_1_TRIP_RESET	
CWP_1_TRIP_TIMER	
CWP_2_AUTO_HMI	
CWP_2_AVAIL	
CWP_2_LEAD	
CWP_2_LEAD_PMP	
CWP_2_RUN	
CWP_2_STOP	
CWP_2_STOP_HMI	
CWP_2_STRT	
CWP_2_STRT_HMI	
CWP_2_TRIP	
CWP_2_TRIP_RESET	
CWP_2_TRIP_TIMER	
DAILY_RESET	
DAYOFWEEK_TIMER	DAY OF THE WEEK\$N1 = SUNDAY\$N7 = SATURDAY
DAY_ONS	
DAY_TANK_DAY_TOT	DIESEL DAY TANK DAILY TOTAL (GALLONS)
DAY_TANK_MONTH_TOT	DIESEL DAY TANK MONTHLY \$N(GALLONS)
DAY_TANK_YEAR_TOTAL	DIESEL DAY TANK YEARLY TOTAL (GALLONS)
DB2_RUN_GAS_EVER_TOTAL	
DB2_RUN_OIL_EVER_TOTAL	
DB_2_ON	
DG1DMD	DG1 MANUAL OUTPUT FROM HMI
DG1LC	DG1 LOAD DEMAND
DG1L_R	DG1 IN REMOTE FROM LOCAL PLC
DG1_ALM_TIMER	
DG1_ERR_CNTR	
DG1_FANAST	
DG1_FANBST	
DG1_FANCST	
DG1_FANDST	
DG1_KW	
DG1_KWH_EVER_TOTAL	
DG1_KWH_MONTH_TOT	
DG1_KWH_YEAR_TOTAL	
DG1_KW_EVER_RATIO	
DG1_KW_LOAD	

NAME	DESCRIPTION
DG1_KW_MONTH_RATIO	DG1 KW MONTHLY RATIO
DG1_KW_YEAR_RATIO	DG1 KW YEARLY RATIO
DG1_LF	DG 1 ACTUAL LOAD
DG1_OILFLOW_EVER_TOTAL	
DG1_OILFLOW_MONTH_TOT	DG1 OIL MONTHLY TOTAL
DG1_OILFLOW_YEAR_TOTAL	DG1 OIL YEARLY TOTAL
DG1_PLC_COMM	DG 1 COMM GOOD
DG1_READS_DINT	
DG1_RUN_EVER_TOTAL	
DG1_RUN_MONTH_TOT	
DG1_RUN_YEAR_TOTAL	
DG1_VFST	
DG2DMD	DG2 MANUAL OUTPUT FROM HMI
DG2LC	DG2 LOAD DEMAND
DG2L_R	DG2 IN REMOTE FROM LOCAL PLC
DG2_ERR_CNTR	
DG2_FANAST	
DG2_FANBST	
DG2_FANCST	
DG2_FANDST	
DG2_KW	
DG2_KWH_EVER_TOTAL	
DG2_KWH_MONTH_TOT	
DG2_KWH_YEAR_TOTAL	
DG2_KW_LOAD	
DG2_LF	DG 2 ACTUAL LOAD
DG2_OILFLOW_EVER_TOTAL	
DG2_OILFLOW_MONTH_TOT	DG2 OIL MONTHLY TOTAL
DG2_OILFLOW_YEAR_TOTAL	DG2 OIL YEARLY TOTAL
DG2_PLC_COMM	DG 2 COMM GOOD
DG2_READS	
DG2_READS_DINT	
DG2_RUN_EVER_TOTAL	
DG2_RUN_MONTH_TOT	
DG2_RUN_YEAR_TOTAL	
DG2_VFST	
DGM	
DGM_PLC_COMM	DG MASTER COMM GOOD
DGVF1SS	DIESEL GENERATOR VENT FAN 1 START / STOP
DGVF1_AUTO_STOP	
DGVF1_AUTO_STRT	
DGVF1_STOP_TIMER	
DGVF1_STRT_TIMER	
DGVF2SS	DIESEL GENERATOR VENT FAN 2 START / STOP
DGVF2_AUTO_STOP	
DGVF2_AUTO_STRT	

NAME	DESCRIPTION
DGVF2_STOP_TIMER	
DGVF2_STRT_TIMER	
DGVF_1_AUTO_HMI	
DGVF_1_AVAIL	
DGVF_1_STOP	
DGVF_1_STOP_HMI	
DGVF_1_STRT_HMI	
DGVF_1_TRIP	
DGVF_1_TRIP_RESET	
DGVF_1_TRIP_TIMER	
DGVF_2_AUTO_HMI	
DGVF_2_AVAIL	
DGVF_2_STOP	
DGVF_2_STOP_HMI	
DGVF_2_STRT_HMI	
DGVF_2_TRIP	
DGVF_2_TRIP_RESET	
DGVF_2_TRIP_TIMER	
DG_M_READS	
DIESEL_DAY_TANK_LOW	START FUEL TRANSFER PUMPS
DIFF_COST_OF_COGEN	DIFFERENTIAL COST OF COGENERATION \$N\$KWhr
DIFF_COST_OF_COGEN_1	HOLDING REGISTER
DIFF_DEMAND_CHARGE	DIFFERENTIAL DEMAND CHARGE
DIFF_DEMAND_CHARGE_REAL	
DOL_PER_DEC_GAS	DOLARS PRE DECOTHERM GAS\$N\$HMI ENTRY
DOL_PER_DEC_OIL	Cost Of Fuel Oil
DOL_PER_GAL_OIL	DOLLARS PER GALLON OIL HMI ENTRY
DO_PLC_COMM	DO COMM GOOD
DPT_400_1_LOW	
DTANK_LVL	DIESEL GENERATOR DAY TANK LEVEL 0-100%
DTANK_TIMER	
EQUIV1_FUEL	EQUIVILANT 1 FUEL\$NDths/hr
EQUIV2_FUEL	EQUIVILANT 2 FUEL\$NDths/hr
ERROR	
ERROR_MAX	
FM4001_EVER1_CNTR	
FM4001_EVER2_CNTR	
FM4001_EVER3_CNTR	
FM4001_EVER4_CNTR	
FM4001_EVER_PULSES	
FM4001_EVER_TOTAL	COOLING TOWER MAKEUP\$NGALLONS TOTALIZED
FM4001_MONTH_CNTR	
FM4001_YEAR_CNTR	
FM8001_DAY_CNTR	
FM8001_EVER1_CNTR	
FM8001_EVER2_CNTR	

NAME	DESCRIPTION
FM8001_EVER3_CNTR	
FM8001_EVER4_CNTR	
FM8001_EVER_PULSES	
FM8001_EVER_TOTAL	DIESEL DAY TANK GALLONS TOTALIZED
FM8001_MONTH_CNTR	DIESEL DAY TANK MONTHLY CONSUMPTION (GALLONS)
FM8001_YEAR_CNTR	
FM_400_1	COOLING TOWER MAKE-UP \$N1 PULSE = 100 GALLON
FM_800_1	DIESEL DAY TANK FUEL OIL\$N1 PULSE = 1 GALLON
FM_800_1_MONTH_TOT	
FM_800_1_YEAR_TOT	
FP1_ST	FIRE ALARM 1
FP2_ST	FIRE ALARM 2
FT903_STMFLOW_EVER_TOTAL	
FT903_STMFLOW_MONTH_TOT	YARD WEST STEAM FLOW MONTHLY TOTAL
FT903_STMFLOW_YEAR_TOTAL	YARD WEST STEAM FLOW YEARLY TOTAL
FT904_STMFLOW_EVER_TOTAL	
FT904_STMFLOW_MONTH_TOT	YARD EAST STEAM FLOW MONTHLY TOTAL
FT904_STMFLOW_YEAR_TOTAL	YARD EAST STEAM FLOW YEARLY TOTAL
FTP1	
FTP2	
FTP_1_AUTO_HMI	
FTP_1_AVAIL	
FTP_1_LEAD_PMP	
FTP_1_STOP	
FTP_1_STOP_HMI	
FTP_1_STRT_HMI	
FTP_1_TRIP	
FTP_1_TRIP_RESET	
FTP_1_TRIP_TIMER	
FTP_2_AUTO_HMI	
FTP_2_AVAIL	
FTP_2_LEAD_PMP	
FTP_2_STOP	
FTP_2_STOP_HMI	
FTP_2_STRT_HMI	
FTP_2_TRIP	
FTP_2_TRIP_RESET	
FTP_2_TRIP_TIMER	
FTP_LEAD_START	
FTP_LEAD_STOP	
FTP_LEAD_STOP_TIMER	
FTP_LEAD_STRT_TIMER	
FT_2005	AC-5 Flow
FT_2005_BQ	
FT_2006	AC-6 Flow
FT_2006_BQ	

NAME	DESCRIPTION
FT_903	YARD WEST 200/125 PRV STEAM FLOW
FT_903_BQ	YARD WEST 200/125 PRV STEAM FLOW BAD QUALITY
FT_903_COMP	
FT_904	YARD EAST 200/125 PRV STEAM FLOW
FT_904_BQ	YARD WEST 200/125 PRV STEAM FLOW BQ
FT_904_COMP	
FT_907	YARD EAST 200/125 PRV No.1 STEAM FLOW
FT_907_BQ	YARD EAST 200/125 PRV No.1 STEAM FLOW BQ
FT_907_COMP	
FT_954	125/5 PRV STATUIN No.2 STEAM FLOW
FT_954_BQ	125/5 PRV STATUIN No.2 STEAM FLOW BQ
FT_954_COMP	
FT_965	No.2 AND 3 DEAERATOR STEAM FLOW
FT_965_BQ	No.2 AND 3 DEAERATOR STEAM FLOW BQ
FT_968	No.1 DEAERATOR STEAM FLOW
FT_968_BQ	No.1 DEAERATOR STEAM FLOW BQ
FT_AC_5_AIRFLOW_TOT	
FT_AC_6_AIRFLOW_TOT	
FT_COMP_AIR_EAST	
FT_COMP_AIR_EAST_BQ	
FT_COMP_AIR_EAST_EVER_TOT	
FT_COMP_AIR_EAST_MONTH_TOT	
FT_COMP_AIR_EAST_YEAR_TOT	
FT_COMP_AIR_TOTAL	
FT_COMP_AIR_TOTAL_BQ	FT Comp Air BQ
FT_COMP_AIR_WEST	
FT_COMP_AIR_WEST_BQ	
FT_COMP_AIR_WEST_EVER_TOT	
FT_COMP_AIR_WEST_MONTH_TOT	
FT_COMP_AIR_WEST_YEAR_TOT	
FT_COND_EAST	
FT_COND_EAST_BQ	
FT_COND_EAST_COMP	
FT_COND_EAST_EVER	
FT_COND_WEST	
FT_COND_WEST_BQ	
FT_COND_WEST_COMP	
FT_COND_WEST_EVER	
FW_FLOW_RANGE_1	
FW_FLOW_RANGE_2	
FW_FLOW_RANGE_3	
FW_FLOW_RANGE_4	
FW_FLOW_RANGE_5	
FW_FLOW_RANGE_6	
FW_FLOW_RANGE_7	
H1HSFR	HRSG 1 RESERVE STEAM FLOW

NAME	DESCRIPTION
H1SF2	HRSG1 STEAM FLOW WITH DUCT BURNERS
H1_COMMS_GOOD	
H1_COMM_COUNTER	
H1_COMM_DN	
H1_COMM_H1_1	
H1_COMM_ONS	
H1_DMD_HARD	
H1_READ_ERRS	
H1_WRITE_ERRS	
H2HSFR	HRSG 2 RESERVE STEAM FLOW
H2SF2	HRSG2 STEAM FLOW WITH DUCT BURNERS
HIGH_DLY	
HLA_983	HIGH PRESSURE EXPANSION TANK HIGH LEVEL ALARM
HLA_984	LOW PRESSURE EXPANSION TANK HIGH LEVEL ALARM
HOL01_DAY	HOLIDAY 1 DAY
HOL01_MTH	HOLIDAY 1 MONTH
HOL02_DAY	HOLIDAY 2 DAY
HOL02_MTH	HOLIDAY 2 MONTH
HOL03_DAY	HOLIDAY 3 DAY
HOL03_MTH	HOLIDAY 3 MONTH
HOL04_DAY	HOLIDAY 4 DAY
HOL04_MTH	HOLIDAY 4 MONTH
HOL05_DAY	HOLIDAY 5 DAY
HOL05_MTH	HOLIDAY 5 MONTH
HOL06_DAY	HOLIDAY 6 DAY
HOL06_MTH	HOLIDAY 6 MONTH
HOL07_DAY	HOLIDAY 7 DAY
HOL07_MTH	HOLIDAY 7 MONTH
HOL08_DAY	HOLIDAY 8 DAY
HOL08_MTH	HOLIDAY 8 MONTH
HOL09_DAY	HOLIDAY 9 DAY
HOL09_MTH	HOLIDAY 9 MONTH
HOL10_DAY	HOLIDAY 10 DAY
HOL10_MTH	HOLIDAY 10 MONTH
HOL11_DAY	HOLIDAY 11 DAY
HOL11_MTH	HOLIDAY 11 MONTH
HORN_DELAY	
HORN_RELAY	HORN BIT FROM INTELLUTION
HORN_TIMER	
HRSG1BM	SPARE DEMAND FOR HRSG1 IS SOFT
HRSG1BM_SOFT	HRSG1 DEMAND VIA ETHERNET
HRSG1DMD	HRSG1 HMI MANUAL OUTPUT
HRSG1L_R	HRSG1 IN LOCAL
HRSG1_1_COMM_ERR	HRSG1_1 COMM LOSS
HRSG1_2_COMM_ERR	HRSG1_2 COMM LOSS
HRSG1_COST_OF_STEAM	HRSG1 COST OF STEAM (\$\$/LB)

NAME	DESCRIPTION
HRSG1_DB_FIRE_EVER_TOTAL	
HRSG1_DB_ON	
HRSG1_DMD_COUNTS	
HRSG1_FEEDWATER_FLOW	HRSG1 FEEDWATER FLOW\$NKPPH
HRSG1_FIRE_RATE	
HRSG1_FWFLOW_EVER_TOTAL	
HRSG1_FWFLOW_MONTH_TOT	HRSG 1 FEEDWATER FLOW TOTALS MONTHLY TOTAL
HRSG1_FWFLOW_YEAR_TOTAL	HRSG 1 FEEDWATER FLOW TOTALS YEARLY TOTAL
HRSG1_GASFLOW_EVER_TOTAL	
HRSG1_GASFLOW_MONTH_TOT	HRSG1 GAS FLOW MONTHLY TOTAL
HRSG1_GASFLOW_YEAR_TOTAL	HRSG1 GAS FLOW YEARLY TOTAL
HRSG1_GAS_FLOW_KSCFH	HRSG1 GAS FLOW (KSCFH)
HRSG1_GAS_FLOW_KSCFM	HRSG1 GAS FLOW (KSCFM)
HRSG1_ON_CNTL	HRSG 1 RUNNING AND IN REMOTE
HRSG1_PLC_COMM	HRSG1 COMMS GOOD
HRSG1_READS_INT	
HRSG1_STEAM_FLOW	HRSG1 STEAM FLOW KPPH
HRSG1_STM	HRSG1 STEAM LBS/HR
HRSG1_STMFLOW_EVER_TOTAL	
HRSG1_STMFLOW_MONTH_TOT	HRSG 1 STEAM FLOW TOTALS MONTHLY TOTAL
HRSG1_STMFLOW_YEAR_TOTAL	HRSG 1 STEAM FLOW TOTALS YEARLY TOTAL
HRSG1_WRITE_COUNTER	
HRSG2BM	SPARE DEMAND FOR HRSG2 IS SOFT
HRSG2BM_SOFT	HRSG2 DEMAND VIA ETHERNET
HRSG2DMD	HRSG 2 MANUAL OUTPUT FROM HMI
HRSG2L_R	HRSG2 IN REMOTE
HRSG2_1_COMM_ERR	HRSG2_1 COMM LOSS
HRSG2_2_COMM_ERR	HRSG2_2 COMM LOSS
HRSG2_3_COMM_ERR	HRSG2_3 COMM LOSS
HRSG2_COST_OF_STEAM	
HRSG2_COST_OF_STEAM_GAS	
HRSG2_COST_OF_STEAM_OIL	HRSG2 COST OF STEAM OIL
HRSG2_DB_FIRE_EVER_TOTAL	
HRSG2_DB_ON	HRSG2 DUCTBURNER ON
HRSG2_DMD_COUNTS	
HRSG2_FIRE_RATE	HRSG2 LOCAL DEMAND
HRSG2_FWFLOW_EVER_TOTAL	
HRSG2_FWFLOW_MONTH_TOT	HRSG2 FEEDWATER FLOW MONTHLY TOTAL
HRSG2_FWFLOW_YEAR_TOTAL	HRSG2 FEEDWATER FLOW YEARLY TOTAL
HRSG2_FW_FLOW	HRSG2 FEEDWATER FLOW\$NKPPH
HRSG2_GASFLOW_EVER_TOTAL	
HRSG2_GASFLOW_MONTH_TOT	HRSG2 GAS FLOW MONTHLY TOTAL
HRSG2_GASFLOW_YEAR_TOTAL	HRSG2 GAS FLOW YEARLY TOTAL
HRSG2_GAS_FLOW_KSCFH	HRSG2 GAS FLOW (KSCFH)
HRSG2_GAS_FLOW_KSCFM	HRSG2 GAS FLOW (KSCFM)
HRSG2_GAS_FLOW_SCFM	

NAME	DESCRIPTION
HRSG2_OILFLOW_EVER_TOTAL	
HRSG2_OILFLOW_MONTH_TOT	HRSG2 OIL FLOW MONTHLY TOTAL
HRSG2_OILFLOW_YEAR_TOTAL	HRSG2 OIL FLOW YEARLY TOTAL
HRSG2_OIL_FLOW_GPM	HRSG2 OIL FLOW (GPM)
HRSG2_OIL_FLOW_PPH	
HRSG2_OIL_ON_DELAY	HRSG2 DB ON OIL DELAY
HRSG2_ON_CNTL	HRSG 2 RUNNING AND IN REMOTE
HRSG2_PLC_COMM	HRSG2 COMMS GOOD
HRSG2_READS	HRSG2 IN LOCAL MODE FROM LOCAL PLC
HRSG2_READS	HRSG2 IN REMOTE
HRSG2_READS	HRSG2 RELEASE TO MODULATE\$N(DB ON)
HRSG2_READS	HRSG2 ON OIL
HRSG2_READS_2	
HRSG2_STEAM_FLOW	HRSG 2 STEAM FLOW
HRSG2_STM	HRSG2 STEAM LBS/HR
HRSG2_STMFLOW_EVER_TOTAL	
HRSG2_STMFLOW_MONTH_TOT	HRSG2 STEAM FLOW MONTHLY TOTAL
HRSG2_STMFLOW_YEAR_TOTAL	HRSG2 STEAM FLOW YEARLY TOTAL
HRSG_1_AUTO	HRSG1 AUTO FROM HMI
HRSG_1_BIAS	HRSG 1 BIAS
HRSG_2_AUTO	HRSG2 AUTO FROM HMI
HRSG_2_BIAS	HRSG2 BIAS FROM HMI
HRSG_2_OIL_SEL	
HRSG_2_OIL_SEL_BMS	OIL SELECTED ON BMS
HS_1001	
HS_1002	CONDENSATE PUMP 2 START/STOP
HS_1002_STOP	CONDENSATE PUMP 2 STOP PULSE
HS_1002_STOP_TIMER	CONDENSATE PUMP 2 STOP PULSE TIMER
HS_1002_STRT	CONDENSATE PUMP 2 START PULSE
HS_1002_STRT_TIMER	CONDENSATE PUMP 2 START PULSE TIMER
HS_1003	
HS_1004	
HS_1005	
HS_1006	
HS_1007	
HS_1008	
HS_1009	
HS_1010	
HS_1011F	AHU-1 FAST START PULSE TIMER
HS_1011S	AHU-1 SLOW START PULSE TIMER
HS_1011_F	AHU-1 FAST START MAINTAINED
HS_1011_FAST	AHU-1 FAST START
HS_1011_S	AHU-1 SLOW START MAINTAINED
HS_1011_SLOW	
HS_1011_STOP	
HS_1012F	

NAME	DESCRIPTION
HS_1012S	
HS_1012_F	
HS_1012_FAST	AIR HANDLING UNIT 2 FAST START
HS_1012_S	
HS_1012_SLOW	AIR HANDLING UNIT 2 SLOW START
HS_1012_STOP	AIR HANDLING UNIT 2 STOP
HS_1013	
HS_1014	
HS_2001_STP	Air Comp #1 Stop
HS_2001_STRT	Air Comp #1 Start
HS_2002_STP	Air Comp #2 Stop
HS_2002_STRT	Air Comp #2 Start
HS_2003_STP	Air Comp #3 Stop
HS_2003_STRT	Air Comp #3 Start
HS_2004_STP	Air Comp #4 Stop
HS_2004_STRT	Air Comp #4 Start
HS_2005_STP	Air Comp #5 Stop
HS_2005_STRT	Air Comp #5 Start
HS_2006_STP	Air Comp #6 Stop
HS_2006_STRT	Air Comp #6 Start
IM_EX_TOTAL	
JK_CTG_1_AUTO	CTG1 IN AUTO FROM HMI
JK_CTG_1_BIAS	CTG1 LOAD BIAS FROM HMI
JK_CTG_2_AUTO	CTG2 IN AUTO FROM HMI
JK_CTG_2_BIAS	CTG2 LOAD BIAS FROM HMI
JK_DEMAND_DG	KILOWATT MASTER DEMAND DIVIDED BY 4 FOR DG MASTER DEMAND
JK_DG_1_AUTO	DG1 IN AUTO FROM HMI
JK_DG_1_BIAS	DG1 LOAD BIAS FROM HMI
JK_DG_2_AUTO	DG2 IN AUTO FROM HMI
JK_DG_2_BIAS	DG2 LOAD BIAS FROM HMI
JK_IM_EX	
JK_IM_EX_DEMAND	KILOWATT MASTER DEMAND
JK_IM_TRKSW	KILOWATT MASTER TRACK SWITCH
JK_IM_TRKVAL	
JK_TEST	
JK_TEST_OUT	
JK_X	
JK_Y	
Josh_B3_Coms_1	
Josh_B3_Coms_2	
Josh_B3_Coms_3	
Josh_B3_Coms_4	
Josh_B3_Coms_5	
Josh_B3_Time_1	
Josh_B3_Time_2	
Josh_B3_Time_3	

NAME	DESCRIPTION
Josh_B3_Time_4	
Josh_B3_Time_5	
Josh_B4_Coms_1	
Josh_B4_Coms_2	
Josh_B4_Coms_3	
Josh_B4_Coms_4	
Josh_B4_Coms_5	
Josh_B4_Time_1	
Josh_B4_Time_2	
Josh_B4_Time_3	
Josh_B4_Time_4	
Josh_B4_Time_5	
Josh_CTG1_Coms_1	
Josh_CTG1_Coms_2	
Josh_CTG1_Coms_3	
Josh_CTG1_Time_1	
Josh_CTG1_Time_2	
Josh_CTG1_Time_3	
Josh_CTG2_Coms_1	
Josh_CTG2_Coms_2	
Josh_CTG2_Time_1	
Josh_CTG2_Time_2	
Josh_DG_Coms_1	
Josh_DG_Coms_2	
Josh_DG_Coms_3	
Josh_DG_Time_1	
Josh_DG_Time_2	
Josh_DG_Time_3	
Josh_HRSG1_Coms_1	
Josh_HRSG1_Coms_2	
Josh_HRSG1_Time_1	
Josh_HRSG1_Time_2	
Josh_HRSG2_Coms_1	
Josh_HRSG2_Coms_2	
Josh_HRSG2_Coms_3	
Josh_HRSG2_Time_1	
Josh_HRSG2_Time_2	
Josh_HRSG2_Time_3	
Josh_PM_Coms_1	
Josh_PM_Coms_2	
Josh_PM_Coms_3	
Josh_PM_Time_1	
Josh_PM_Time_2	
Josh_PM_Time_3	
JOY_1st_ON	
JOY_2nd_ON	

NAME	DESCRIPTION
JOY_3rd_ON	
JOY_4th_ON	
JT_IMEX	UTILITY IMPORT/EXPORT POWER
JT_IMEX_BQ	UTILITY IMPORT/EXPORT POWER BQ
JT_IMEX_WIDE	IMPORT EXPORT TRANSDUCER WIDE RANGE
JT_IMEX_WIDE_BQ	IMPORT METER WIDE RANGE RAW BAD QUALITY
JT_IMEX_WIDE_RAW	IMPORT METER WIDE RANGE RAW
JT_IM_2	Second Franklin Import XMTR
JT_IM_2_BQ	XMTR BQ
K_REVERSE30	
K_START	
K_STOP	
LIC_910	DEAERATOR No.1 LEVEL CONTROLLER
LIC_911	DEAERATOR No.2 LEVEL CONTROLLER
LIC_912	DEAERATOR No.3 LEVEL CONTROLLER
LIC_913	CONDENSATE TANK LEVEL CONTROLLER
LIC_918	FEED WATER HEAD TANK LEVEL CONTROLLER
LIC_921	HEAD TANK LEVEL CONTROLLER
LIC_922	CONTINUOUS BLOWDOWN LEVEL CONTROLLER
LIK_200_1	
LIK_200_2	
LIK_911	
LIK_912	
LIK_913	
LIK_918	
LIK_922	
LOAD1PCT	CTG 1 LOAD IN PERCENT
LOAD2PCT	CTG 2 LOAD IN PERCENT
LOW_DLY	
LS_200_1	DEAREATOR LEVEL\$NHI
LS_200_1_DIG	DEAREATOR LEVEL\$NHI
LS_200_2	DEAREATOR LEVEL\$NHI-HI
LS_200_2_DIG	DEAREATOR LEVEL\$NHI-HI
LS_200_3	DEAREATOR LEVEL\$NLOW
LS_200_3_DIG	DEAREATOR LEVEL\$NLOW
LS_200_4	DEAREATOR LEVEL\$NLOW-LOW
LS_200_4_DIG	DEAREATOR LEVEL\$NLOW-LOW
LS_200_LATCH	
LS_400_1	
LS_400_2	
LS_400_3	
LS_400_4	
LT_400_1	COOLING TOWER SUMP LEVEL
LT_400_1_BQ	COOLING TOWER SUMP LEVEL BQ
LT_400_1_SP	
LT_400_1_SP_HI	

NAME	DESCRIPTION
LT_400_1_SP_LO	
LT_910	DEAERATOR No.1 LEVEL
LT_910_BQ	DEAERATOR No.1 LEVEL BQ
LT_911	DEAERATOR No.2 LEVEL
LT_911_BQ	DEAERATOR No.2 LEVEL BQ
LT_911_HIGH	
LT_911_LOW	
LT_912	DEAERATOR No.3 LEVEL
LT_912_BQ	DEAERATOR No.3 LEVEL BQ
LT_912_HIGH	
LT_912_LOW	
LT_913	CONDENSATE TANK LEVEL
LT_913_BQ	CONDENSATE TANK LEVEL BQ
LT_913_HI	
LT_913_LOW	
LT_918	FEEDWATER HEAD TANK LEVEL
LT_918_BQ	FEEDWATER HEAD TANK LEVEL BQ
LT_918_HIGH	
LT_918_LOW	
LT_922	CONTINUOUS BLOWDOWN TANK LEVEL
LT_922_BQ	CONTINUOUS BLOWDOWN TANK LEVEL BQ
LT_940	FUEL OIL TANK No. 1 LEVEL
LT_940_BQ	FUEL OIL TANK No. 1 LEVEL BQ
LT_941	FUEL OIL TANK No. 2 LEVEL
LT_941_BQ	FUEL OIL TANK No. 2 LEVEL BQ
MAN_RESET	
MB_AC_1_40001	SYSTEM SETPOINT
MB_AC_1_KW	KW Calculated
MB_AC_1_RAW	
MB_AC_2_40001	
MB_AC_2_KW	KW Calculated
MB_AC_2_RAW	
MB_AC_3_40001	
MB_AC_3_KW	KW Calculated
MB_AC_3_RAW	
MB_AC_4_40001	
MB_AC_4_KW	KW Calculated
MB_AC_4_RAW	
MB_AC_5_40269_T2	
MB_AC_5_KW	KW Calculated
MB_AC_5_RAW	
MB_AC_6_40112	Target SetPoint
MB_AC_6_40113	Stop SetPoint
MB_AC_6_40114	Immediate Stop SP
MB_AC_6_ALARM	
MB_AC_6_KWh_Calc_1	Intermediate Math

NAME	DESCRIPTION
MB_AC_6_LOADED	
MB_AC_6_MAX_SPEED	
MB_AC_6_MIN_SPEED	
MB_AC_6_RAW	
MB_AC_6_REMOTE	
MB_AC_6_RUNNING	AC #6 Run FB (Mdb)
MB_AC_6_WARNING	
MCM	
MCMRCmdExecute	
MCMRCmdExecute_AC	
MCMRCmds	
MCMRCmds_AC	
MCM_AC	
MED_DLY	
MJFAULTS	
MONTH_DATE_REAL_PEAK	
MONTHLY_RESET	
MONTH_ONS	
MONTH_PEAK_TIME_PEAK	
MONTH_SHLDR_TIME_PEAK	
MSG_15_SEC_TIMER	
MSG_5_SEC_TIMER	
MSG_BLR3_1_L	
MSG_BLR3_2_L	
MSG_BLR3_3_L	
MSG_BLR3_4_L	
MSG_BLR3_5_L	
MSG_BLR4_1_L	
MSG_BLR4_2_L	
MSG_BLR4_3_L	
MSG_BLR4_4_L	
MSG_BLR4_5_L	
MSG_CTG1_1_L	
MSG_CTG1_2_L	
MSG_CTG1_3_L	
MSG_CTG2_2_L	
MSG_CTG2_L	
MSG_DG1_L	
MSG_DG2_L	
MSG_DG3_L	
MSG_DGM_L	
MSG_HRSG2_1_L	
MSG_HRSG2_2_L	
MSG_HRSG2_3_L	
MSG_JVA_1_L	
MSG_JVA_dncntr	

NAME	DESCRIPTION
MSG_JVA_L	
MSG_RESET	
MSG_SEQ	MESSAGE COMMAND SEQUENCE\$N1=SEQ\$N0=TIME
MS_1001	CONDENSATEN PUMP 1 RUN STATUS
MS_1002	CONDENSATEN PUMP 2 RUN STATUS
MS_1003	RAW WATER BOOSTER PUMP 1 RUN STATUS
MS_1004	RAW WATER BOOSTER PUMP 2 RUN STATUS
MS_1005	RAW WATER BOOSTER PUMP 3 RUN STATUS
MS_1006	RAW WATER BOOSTER PUMP 4 RUN STATUS
MS_1007	VENT FAN 8 RUN STATUS
MS_1008	VENT FAN 7 RUN STATUS
MS_1009	VENT FAN 8 RUN STATUS
MS_1010	VENT FAN 9 RUN STATUS
MS_1011F	AHU-1 FAST RUNNING
MS_1011S	AHU-1 SLOW RUNNING
MS_1012F	AHU-2 FAST RUNNING
MS_1012S	AHU-2 SLOW RUNNING
MS_2001	Air Comp #1 Running
MS_2002	Air Comp #2 Running
MS_2003	Air Comp #3 Running
MS_2004	Air Comp #4 Running
MS_2005	Air Comp #5 Running\$N(Centec)
MS_2006	Air Comp #6 Running\$N(Nirvana)
MS_971	FUEL OIL PUMP 1 RUN STATUS
MS_972	FUEL OIL PUMP 2 RUN STATUS
NWOP_DEL_CHRG	NON WINTER OFF PEAK DELIVERY CHARGE
OFFPEAK_DATE	POWER STATUS\$NOFF PEAK\$NFROM DATE
OFFPEAK_DAY	POWER STATUS\$NOFF PEAK\$NFROM DAY
OFFPEAK_DEL_CHARGE	OFF PEAK DELIVERY CHARGE (WINTER)
OFFPEAK_DEL_CHARGE_NW	OFF PEAK DELIVERY CHARGE (NON WINTER)
OFFPEAK_HOL	POWER STATUS\$NOFF PEAK\$NFROM HOLIDAY
OFFPEAK_POWER	POWER STATUS\$NOFF PEAK
OFFPEAK_SUP_RATE	OFFPEAK CURRENT DEMAND CHARGE (WINTER)
OFFPEAK_SUP_RATE_NW	OFFPEAK SUPPLT RATE (NON WINTER)
ONE_JOY_ON	
ONE_MIN_TIMER	
ONE_SHOT	
ONS_100	
ONS_101	
ONS_102	
ONS_103	
ONS_104	
ONS_105	
ONS_106	
ONS_107	
ONS_108	

NAME	DESCRIPTION
ONS_109	
ONS_110	
ONS_111	
ONS_112	
ONS_113	
ONS_114	
ONS_115	
ONS_116	
ONS_117	
ONS_118	
ONS_119	
ONS_120	
ONS_121	
ONS_122	
ONS_123	
ONS_124	
ONS_125	
ONS_126	
ONS_DGM	
ON_PEAK_COST	ON PEAK COST
ON_SHOULDER_PEAK_COST	ON SHOULDER COST
OSR1	
O_AND_M_COST_CT1	O&M COST\$N\$/HR HMI ENTRY
O_AND_M_COST_CT2	
PDT_400_1	COOLING WATER DIFFERENTIAL PRESSURE
PDT_400_1_BQ	COOLING WATER DIFFERENTIAL PRESSURE BQ
PDT_400_1_TRK_SW	
PEAK	
PEAK_DEL_CHARGE	PEAK DELIVERY CHARGE (WINTER)
PEAK_DEL_CHARGE_NW	PEAK DELIVERY CHARGE (NON WINTER)
PEAK_DMD_CHARGE	PEAK CURRENT DEMAND CHARGE (WINTER)
PEAK_DMD_CHARGE_NW	PEAK DEMAND CHARGE (NON WINTER)
PEAK_ons	
PEAK_POWER	POWER STATUS\$NPEAK
PEAK_SUP_RATE	PEAK CURRENT SUPPLT RATE (WINTER)
PEAK_SUP_RATE_NW	PEAK SUPPLY RATE (NON WINTER)
PEAK_timer	
PEAK_Timer_reset	
PH_400_1	COOLING WATER pH
PH_400_1_BQ	COOLING WATER pH BQ
PIC_903	YARD WEST PRESSURE CONTROLLER
PIC_904	YARD EAST PRESSURE CONTROLLER
PIC_907	125/5 No.1 PRESSURE CONTROLLER
PIC_908	125/5 No.2 PRESSURE CONTROLLER
PIK_100	BOILER MASTER
PIK_100_1	

NAME	DESCRIPTION
PIK_100_2	
PIK_100_DEMAND	PRESSURE MASTER DEMAND
PIK_100_GAIN	BOILER MASTER GAIN CONSTANT
PIK_100_PV_SEL	PV SELECTOR
PIK_100_RESET	
PIK_100_TRKSW	
PIK_400_1	
PIK_903	
PIK_904	
PIK_907	
PIK_908	
PLANT_MONTH_FEEDWATER	TOTAL PLANT FEEDWATER MONTHLY TOTAL
PLANT_MONTH_KWH	TOTAL PLANT MWH MONTHLY TOTAL
PLANT_MONTH_STEAM	TOTAL PLANT STEAM MONTHLY TOTAL (MLBS)
PLANT_POWER	PLANT POWER FOR CHP OPTIMIZATION PROGRAM
PLANT_TOTAL_FW_FLOW	TOTAL PLANT FEEDWATER FLOW
PLANT_TOTAL_KW	PLANT TOTAL KW
PLANT_TOTAL_STEAM_FLOW	TOTAL PLANT STEAM FLOW (KPPH)
PLANT_YEAR_FEEDWATER	TOTAL PLANT FEEDWATER YEARLY TOTAL
PLANT_YEAR_KWH	TOTAL PLANT MWH YEARLY TOTAL
PLANT_YEAR_STEAM	TOTAL PLANT STEAM YEARLY TOTAL (MLBS)
PMCTG2_L	
PMCTG2_READS	
PMDG1_L	
PMDG1_READS	
PMDG2_L	
PMDG2_READS	
PROD_PWR_KW	COST OF PNS PRODUCED POWER\$N\$\$/KWhr
PT_100_1	MAIN 200# STEAM HEADER PRESSURE
PT_100_1_BQ	MAIN 200# STEAM HEADER PRESSURE BQ
PT_100_1_HIGH	
PT_100_2	NORTH HEADER STEAM HEADER PRESSURE
PT_100_2_BQ	NORTH HEADER STEAM HEADER PRESSURE BQ
PT_100_2_HIGH	
PT_100_3	SOUTH HEADER STEAM HEADER PRESSURE
PT_100_3_BQ	SOUTH HEADER STEAM HEADER PRESSURE BQ
PT_100_ERR	
PT_100_FAULT	
PT_100_SEL	
PT_220_1	DEAERATOR No.1 STEAM PRESSURE
PT_220_1_BQ	DEAERATOR No.1 STEAM PRESSURE BQ
PT_220_2	BOILER FEED PUMP SUCTION HEADER PRESSURE
PT_220_2_BQ	BOILER FEED PUMP SUCTION HEADER PRESSURE BQ
PT_220_3	BOILER FEED PUMP DISCHARGE HEADER PRESSURE
PT_220_3_BQ	BOILER FEED PUMP DISCHARGE HEADER PRESSURE BQ
PT_903	YARD WEST 200/125 PRV STEAM PRESSURE

NAME	DESCRIPTION
PT_903_BQ	YARD WEST 200/125 PRV STEAM PRESSURE BQ
PT_903_XVAL	
PT_903_YVAL	
PT_904	YARD EAST 200/125 PRV STEAM PRESSURE
PT_904_BQ	YARD EAST 200/125 PRV STEAM PRESSURE BQ
PT_907	YARD EAST 200/125 PRV No.1 STEAM PRESSURE
PT_907_BQ	YARD EAST 200/125 PRV No.1 STEAM PRESSURE BQ
PT_907_XVAL	
PT_907_YVAL	
PT_908	YARD EAST 200/125 PRV No.2 STEAM PRESSURE
PT_908_BQ	YARD EAST 200/125 PRV No.2 STEAM PRESSURE BQ
PT_919	FUEL OIL HEADER PRESSURE
PT_919_BQ	FUEL OIL HEADER PRESSURE BQ
PT_920	NATURAL GAS HEADER PRESSURE
PT_920_BQ	NATURAL GAS HEADER PRESSURE BQ
PT_942	RAW WATER PRESSURE
PT_942_BQ	RAW WATER PRESSURE BQ
PT_943	COOLING WATER PRESSURE
PT_943_BQ	COOLING WATER PRESSURE BQ
PT_944	ATOMIZING STEAM PRESSURE
PT_944_BQ	ATOMIZING STEAM PRESSURE BQ
PT_947	INSTRUMENT AIR PRESSURE
PT_947_BQ	INSTRUMENT AIR PRESSURE BQ
PT_948	PLANT AIR PRESSURE
PT_948_BQ	PLANT AIR PRESSURE BQ
PT_COMP_AIR	
PT_COMP_AIR_BQ	
REAL_ON_PEAK_COST	REAL ON PEAK COST
REAL_ON_SHOULDER_PEAK_COST	REAL ON SHOULDER PEAK COST
REAL_SHLDR_PEAK	REAL SHOULDER PEAK
RIO_CD1CH0	
RIO_CD1CH1	
RIO_CD1CH10	
RIO_CD1CH11	
RIO_CD1CH12	
RIO_CD1CH13	
RIO_CD1CH14	
RIO_CD1CH15	
RIO_CD1CH2	
RIO_CD1CH3	
RIO_CD1CH4	
RIO_CD1CH5	
RIO_CD1CH6	
RIO_CD1CH7	
RIO_CD1CH8	
RIO_CD1CH9	

NAME	DESCRIPTION
RST_200_1	BFP 1 RUN STATUS
RST_200_2	BFP 2 RUN STATUS
RST_200_3	BFP 3 RUN STATUS
RST_200_4	BFP 4 RUN STATUS
RWP_1_AUTO_HMI	
RWP_1_AUTO_STOP	
RWP_1_AUTO_STRT	
RWP_1_AVAIL	
RWP_1_RUN_TOT	
RWP_1_RUN_TOT_RESET	
RWP_1_STOP	
RWP_1_STOP_HMI	
RWP_1_STRT_HMI	
RWP_1_TRIP	
RWP_1_TRIP_RESET	
RWP_1_TRIP_TIMER	
RWP_2_AUTO_HMI	
RWP_2_AUTO_STOP	
RWP_2_AUTO_STRT	
RWP_2_AVAIL	
RWP_2_STOP	
RWP_2_STOP_HMI	
RWP_2_STRT_HMI	
RWP_2_TRIP	
RWP_2_TRIP_RESET	
RWP_2_TRIP_TIMER	
RWP_3_AUTO_HMI	
RWP_3_AUTO_STOP	
RWP_3_AUTO_STRT	
RWP_3_AVAIL	
RWP_3_STOP	
RWP_3_STOP_HMI	
RWP_3_STRT_HMI	
RWP_3_TRIP	
RWP_3_TRIP_RESET	
RWP_3_TRIP_TIMER	
RWP_4_AUTO_HMI	
RWP_4_AUTO_STOP	
RWP_4_AUTO_STRT	
RWP_4_AVAIL	
RWP_4_STOP	
RWP_4_STOP_HMI	
RWP_4_STRT_HMI	
RWP_4_TRIP	
RWP_4_TRIP_RESET	
RWP_4_TRIP_TIMER	

NAME	DESCRIPTION
SATORSUN	DAY OF WEEK IS SATURDAY OR SUNDAY
SCANTIME	
SEQ_COUNTER	
SHOULDER_DATE	POWER STATUS\$NSHOULDER\$NFROM DATE
SHOULDER_DAY	POWER STATUS\$NSHOULDER\$NFROM DAY
SHOULDER_DEL_CHARGE	SHOULDER DELIVERY CHARGE (WINTER)
SHOULDER_DEL_CHARGE_NW	SHOULDER DELIVERY CHARGE (NON WINTER)
SHOULDER_DMD_CHARGE	SHOLDER CURRENT DEMAND CHARGE (WINTER)
SHOULDER_DMD_CHARGE_NW	SHOULDER DEMAND CHARGE (NON WINTER)
SHOULDER_POWER	POWER STATUS\$NSHOULDER
SHOULDER_SUP_RATE	SHOLDER CURRENT DEMAND CHARGE (WINTER)
SHOULDER_SUP_RATE_NW	SHOULDER SUPPLY RATE (NON WINTER)
SIK_VFD_1	
SIK_VFD_1_TRK_SW	
SIK_VFD_1_TRK_VAL	
SIK_VFD_2	
SIK_VFD_2_TRK_SW	
SIK_VFD_2_TRK_VAL	
SIK_VFD_3	
SIK_VFD_3_TRK_SW	
SIK_VFD_3_TRK_VAL	
SI_CWP1	
SI_CWP2	
SS_200_1	BOILER FEED PUMP 1 PERM / STOP
SS_200_2	BOILER FEED PUMP 2 PERM / STOP
SS_200_3	BOILER FEED PUMP 3 PERM / STOP
SS_200_4	BOILER FEED PUMP 4 PERM / STOP
StatusMsgData	
StatusMsgData_AC	
TC_932A	AHU No.1 TEMPERATURE
TC_932A_BQ	AHU No.1 TEMPERATURE BQ
TC_932B	AHU No.1 FREEZETEMPERATURE
TC_932B_BQ	AHU No.1 FREEZETEMPERATURE BQ
TC_933A	AHU No.2 TEMPERATURE
TC_933A_BQ	AHU No.2 TEMPERATURE BQ
TC_933B	AHU No.2 FREEZETEMPERATURE
TC_933B_BQ	AHU No.2 FREEZETEMPERATURE BQ
TG1LC	CTG1 LOAD DEMAND
TG1L_R	CTG1 IN REMOTE FROM LOCAL PLC
TG1_LF	CTG 1 ACTUAL LOAD
TG2LC	CTG2 LOAD DEMAND
TG2L_R	CTG2 IN REMOTE FROM LOCAL PLC
TG2_LF	CTG 2 ACTUAL LOAD
TIK_400_1	
TIME1	
TIME1	Year

NAME	DESCRIPTION
TIME1	Month (1-12)
TIME1	Day (1-31)
TIME1	Hour (0-23)
TIME1	Minute (0-59)
TIME1	Seconds (0-59)
TIME1	Microseconds (0-999,999)
Timer_reset	
TLT_FW_FLOW	
Toggle	
TOTAL_DEMAND	TOTAL DEMAND
TOTAL_OIL_FLOW	PLANT TOTAL OIL FLOW (GPM)
TOTAL_REAL_DEMAND	TOTAL REAL DEMAND
TOT_GAS_FLOW	TOTAL GAS FLOW (KSCFH)
TOT_GAS_FLOW_MONTH	TOTAL GAS FLOW MONTH (MMSCF)
TOT_GAS_FLOW_YEAR	TOTAL GAS FLOW YEAR (MMSCF)
TOT_OIL_FLOW_MONTH	TOTAL MONTHLY OIL USAGE\$NGALLONS X 1000
TOT_OIL_FLOW_YEAR	TOTAL YEARLY OIL USAGE\$NGALLONS X 1000
TOT_RESET	
TRANS_CHARGE_NC	
TRANS_CHARGE_REAL	REAL TRANSMISSION CHARGE
TSR	TOTAL RESERVE STEAM
TT_2001A	
TT_2001A_BQ	
TT_2001B	
TT_2001B_BQ	
TT_2002A	
TT_2002A_BQ	
TT_2002B	
TT_2002B_BQ	
TT_2003A	
TT_2003A_BQ	
TT_2003B	
TT_2003B_BQ	
TT_2004A	
TT_2004A_BQ	
TT_2004B	
TT_2004B_BQ	
TT_2005A	
TT_2005A_BQ	
TT_2005B	
TT_2005B_BQ	
TT_2006A	
TT_2006A_BQ	
TT_2006B	
TT_2006B_BQ	
TT_220_1	BOILER FEED WATER HEADER TEMPERATURE

NAME	DESCRIPTION
TT_220_1_BQ	BOILER FEED WATER HEADER TEMPERATURE BQ
TT_220_4	DEAERATOR No.1 STORAGE TANK TEMPERATURE
TT_220_4_BQ	DEAERATOR No.1 STORAGE TANK TEMPERATURE BQ
TT_400_1	COOLING TOWER SUMP 1 TEMPERATURE
TT_400_1_BQ	COOLING TOWER SUMP 1 TEMPERATURE BQ
TT_400_2	COOLING TOWER SUMP 2 TEMPERATURE
TT_400_2_BQ	COOLING TOWER SUMP 2 TEMPERATURE BQ
TT_400_3	COOLING TOWER SUMP 3 TEMPERATURE
TT_400_3_BQ	COOLING TOWER SUMP 3 TEMPERATURE BQ
TT_400_4	COOLING WATER SUPPLY HEADER TEMPERATURE
TT_400_4_BQ	COOLING WATER SUPPLY HEADER TEMPERATURE BQ
TT_400_4_TIMER	
TT_400_5	COOLING WATER RETURN\$NHEADER TEMPERATURE
TT_400_5_BQ	COOLING WATER RETURN\$NHEADER TEMPERATURE BQ
TT_400_6	GT-1 LUBE OIL COOLER OUTLET WATER TEMPERATURE
TT_400_6_BQ	GT-1 LUBE OIL COOLER OUTLET WATER TEMPERATURE BQ
TT_400_7	GT-2 LUBE OIL COOLER OUTLET WATER TEMPERATURE
TT_400_7_BQ	GT-2 LUBE OIL COOLER OUTLET WATER TEMPERATURE BQ
TT_400_8	COOLING WATER PUMP HEADER TEMPERATURE
TT_400_8_BQ	COOLING WATER PUMP HEADER TEMPERATURE BQ
TT_903	YARD WEST 200/125 PRV STEAM TEMPERATURE
TT_903_BQ	YARD WEST 200/125 PRV STEAM TEMPERATURE BQ
TT_903_XVAL	
TT_903_YVAL	
TT_904	YARD EAST 200/125 PRV STEAM TEMPERATURE
TT_904_BQ	YARD EAST 200/125 PRV STEAM TEMPERATURE BQ
TT_907	YARD EAST 200/125 PRV No.1 STEAM TEMPERATURE
TT_907_BQ	YARD EAST 200/125 PRV No.1 STEAM TEMPERATURE BQ
TT_907_XVAL	
TT_907_YVAL	
TT_909	200 PSIG HEADER SUPERHEAT TEMPERATURE
TT_909_BQ	200 PSIG HEADER SUPERHEAT TEMPERATURE BQ
TT_946	CONDENSATE TEMPERATURE
TT_946_BQ	CONDENSATE TEMPERATURE BQ
TT_OAT	OUTDOOR AIR TEMPERATURE
TT_OAT_BQ	OUTDOOR AIR TEMPERATURE BQ
TWO_JOYs_ON	
UA_2005	Air Comp #5 Tripped (Centec)
UA_2006	Air Comp #6 Alarm (Nirvana)
UI_2005A	Air Comp #5 REMOTE\$N(Centec)
UI_2005B	Air Comp #5 Loaded\$N(Centec)
VF1_AUTO_STOP	
VF1_AUTO_STRT	
VF2_AUTO_STOP	
VF2_AUTO_STRT	
VF3_AUTO_STOP	

NAME	DESCRIPTION
VF3_AUTO_STRT	
VF4_AUTO_STOP	
VF4_AUTO_STRT	
VF_1_AUTO_HMI	
VF_1_AVAIL	
VF_1_STOP	
VF_1_STOP_HMI	
VF_1_STRT_HMI	
VF_1_TRIP	
VF_1_TRIP_RESET	
VF_1_TRIP_TIMER	
VF_2_AUTO_HMI	
VF_2_AVAIL	
VF_2_STOP	
VF_2_STOP_HMI	
VF_2_STRT_HMI	
VF_2_TRIP	
VF_2_TRIP_RESET	
VF_2_TRIP_TIMER	
VF_3_AUTO_HMI	
VF_3_AVAIL	
VF_3_STOP	
VF_3_STOP_HMI	
VF_3_STRT_HMI	
VF_3_TRIP	
VF_3_TRIP_RESET	
VF_3_TRIP_TIMER	
VF_4_AUTO_HMI	
VF_4_AVAIL	
VF_4_STOP	
VF_4_STOP_HMI	
VF_4_STRT_HMI	
VF_4_TRIP	
VF_4_TRIP_RESET	
VF_4_TRIP_TIMER	
VS_400_1	
VS_400_2	
VS_400_3	
WarmBoot	
WarmBoot_AC	
WINTER_MODE	WINTER MODE
WOP_DEL_CHRG	WINTER OFF PEAK DELIVERY CHARGE
XC_987_FAIL_TIMER	
YEARLY_RESET	
YEAR_ONS	
ZA_200X	Air Compressor CO Level NOT HIGH

NAME	DESCRIPTION
ZSC_2011	AC #1 Cooling Water Valve Closed
ZSC_2012	AC #2 Cooling Water Valve Closed
ZSC_2013	AC #3 Cooling Water Valve Closed
ZSC_2014	AC #4 Cooling Water Valve Closed
ZSC_2015	AC #5 Cooling Water Valve Closed
ZSC_2016	AC #6 Cooling Water Valve Closed
ZSO_2011	AC #1 Cooling Water Valve Open
ZSO_2012	AC #2 Cooling Water Valve Open
ZSO_2013	AC #3 Cooling Water Valve Open
ZSO_2014	AC #4 Cooling Water Valve Open
ZSO_2015	AC #5 Cooling Water Valve Open
ZSO_2016	AC #6 Cooling Water Valve Open
BLR3_COMMS_1P	
BLR3_COMMS_2P	
BLR3_COMMS_3P	
BLR3_COMMS_4P	
BLR3_COMMS_5P	
BLR4_COMMS_1P	
BLR4_COMMS_2P	
BLR4_COMMS_3P	
BLR4_COMMS_4P	
BLR4_COMMS_5P	
CMDMSG0	
CMDMSG1	
DG_1_COMMS	
DG_2_COMMS	
DG_3_COMMS	
DG_M_COMMS	
MSG_CTG1_1	
MSG_CTG1_2	
MSG_CTG1_3	
MSG_CTG2	
MSG_CTG2_2	
MSG_HRSG2_1	
MSG_HRSG2_2	
MSG_HRSG2_3	
MSG_JVA	
MSG_JVA_1	
PMCTG2_COMMS_P	
PMDG1_COMMS_P	
PMDG2_COMMS_P	
SLAVES0	
SLAVES1	
STATMSG	
STATMSG_AC	
UCMDMSG0	

NAME	DESCRIPTION
UCMDMSG0_AC	
UCMDMSG1	
NAME	DESCRIPTION
ABS_01	
AC_1_STRT_MEM	
AC_2_STRT_MEM	
AC_3_STRT_MEM	
AC_4_STRT_MEM	
AC_5_AUTO_LOAD	
AC_5_AUTO_UNLOAD	
AC_5_RUN_UNL	
AC_5_RUN_UNLOADED_TMR	
AC_Centec_SP_Read_1	
AIR_FREEZE	
AIR_HIGH	
AIR_HIHI	
AIR_LOLO	
AIR_LOW	
AIR_MED	
Air_Mode_Freeze_AUTO	
Air_Mode_High_AUTO	
AIR_MODE_HIGH_AUTO_DLY	
Air_Mode_HIHI_AUTO	
Air_Mode_LOLOzzz	Air Comp Mode\$NLOLO Flow
Air_Mode_LOLO_AUTO	
Air_Mode_LOW_AUTO	
AIR_MODE_LOW_AUTO_DLY	
Air_Mode_MED_AUTO	
AIR_MODE_MED_AUTO_DLY	
AIR_MT_STRING	
AUTO_STOP_1st_JOY	
AUTO_STOP_2nd_JOY	
AUTO_STOP_3rd_JOY	
AUTO_STOP_4th_JOY	
A_STP_1st_Joy_Pls	
A_STP_2nd_Joy_Pls	
A_STP_3rd_Joy_Pls	
A_STP_4th_Joy_Pls	
A_STP_AC_5_Pls	
A_STP_AC_6_Pls	
A_STRT_1st_Joy_Pls	
A_STRT_2nd_Joy_Pls	
A_STRT_3rd_Joy_Pls	
A_STRT_4th_Joy_Pls	
A_STRT_AC_5_Pls	
A_STRT_AC_6_Pls	

NAME	DESCRIPTION
BAND_01	
BAND_02	
BAND_03	
BAND_04	
BAND_05	
BAND_06	
BAND_07	
BAND_08	
BAND_10	
BAND_11	
BLR3_FIRE_RATE	
BNOT_01	
BNOT_02	
BNOT_03	
BNOT_06	
BNOT_07	
BNOT_08	
BNOT_19	
BNOT_20	
BOR_02	
BOR_03	
BOR_04	
BOR_05	
BOR_06	
BOR_07	
Centec_ON	Centec On\$NDELAYED
Centec_ON_Dly	
DIV_01	
DIV_02	
DIV_03	
DIV_04	
DIV_05	
EQU_01	
EQU_02	
EQU_04	
EQU_05	
ESEL_01	
ESEL_02	
ESEL_03	
ESEL_04	
ESEL_06	
ESEL_07	
ESEL_09	
ESEL_10	
FGEN_01	
FGEN_02	

NAME	DESCRIPTION
FGEN_03	
FGEN_04	
FGEN_05	
FGEN_06	
FGEN_07	
FGEN_08	
FGEN_09	
GEQ_01	
GRT_01	
GRT_02	
GRT_03	
GRT_04	
GRT_05	
GRT_06	
GRT_07	
GRT_08	
GRT_09	
GRT_10	
GRT_11	
GRT_12	
GRT_13	
GRT_14	
GRT_15	
GRT_16	
GRT_17	
GRT_18	
GRT_19	
GRT_20	
GRT_21	
GRT_22	
GRT_23	
GRT_24	
GRT_25	
GRT_26	
GRT_27	
GRT_28	
GRT_29	
GRT_30	
GRT_31	
HLL_01	
HLL_02	
HLL_03	
HLL_04	
HLL_05	
HLL_06	
HLL_07	

NAME	DESCRIPTION
HLL_08	
HLL_09	
HLL_10	
HLL_11	
HLL_12	
HLL_13	
HLL_14	
HLL_15	
HLL_16	
HLL_17	
HRSG1_COMM_TIMER	
JOY_1st_AUTO	
Joy_1st_ON_Dly	
JOY_2nd_AUTO	
JOY_2nd_Dly	
Joy_2nd_ON_Dly	
JOY_3rd_AUTO	
JOY_3rd_Dly	
Joy_3rd_ON_Dly	
JOY_4th_AUTO	
JOY_4th_Dly	
Joy_4th_ON_Dly	
JOY_Frz_Dly	
JOY_Frz_Dly_2	
JT_IMEX_PV	
JT_IMEX_PV_BQ	Import Export Xmtrs BAD QUALITY
LIM_01	
LIM_02	
LIM_06	
MB_AC_1_30001	System Pressure
MB_AC_1_30002	Discharge Pressure
MB_AC_1_30003	3rd Stage Inlet Temp
MB_AC_1_30004	1sr Stage Vibration
MB_AC_1_30005	2nd Stage Vibration
MB_AC_1_30006	3rd Stage Vibration
MB_AC_1_30007	4th Stage Vibration
MB_AC_1_30008	Oil Pressure
MB_AC_1_30009	Oil Press B4 Filter
MB_AC_1_30010	Oil Filter DP
MB_AC_1_30011	Oil Temp
MB_AC_1_30012	Oil Resivior Normal
MB_AC_1_30013	Stator A Temp
MB_AC_1_30014	Stator B Temp
MB_AC_1_30015	Stator C Temp
MB_AC_1_30016	INBD Mtr Brg Temp
MB_AC_1_30017	OutBrd Mtr Brg Temp

NAME	DESCRIPTION
MB_AC_1_30018	Motor Current
MB_AC_1_30019	System Flow
MB_AC_1_30020	Motor Running
MB_AC_1_30021	Emergency Stop
MB_AC_1_30022	CO Monitor Active
MB_AC_1_30023	SurgeWatch Motor
MB_AC_1_30024	Surge Count
MB_AC_1_30025	Surge Control Point
MB_AC_1_30026	Inlet Postion
MB_AC_1_30027	Blow Off Position
MB_AC_2_30001	System Pressure
MB_AC_2_30002	Discharge Pressure
MB_AC_2_30003	3rd Stage Inlet Temp
MB_AC_2_30004	1sr Stage Vibration
MB_AC_2_30005	2nd Stage Vibration
MB_AC_2_30006	3rd Stage Vibration
MB_AC_2_30007	4th Stage Vibration
MB_AC_2_30008	Oil Pressure
MB_AC_2_30009	Oil Press B4 Filter
MB_AC_2_30010	Oil Filter DP
MB_AC_2_30011	Oil Temp
MB_AC_2_30012	Oil Resivior Normal
MB_AC_2_30013	Stator A Temp
MB_AC_2_30014	Stator B Temp
MB_AC_2_30015	Stator C Temp
MB_AC_2_30016	INBD Mtr Brg Temp
MB_AC_2_30017	OUTBD Mtr Brg Temp
MB_AC_2_30018	Motor Current
MB_AC_2_30019	System Flow
MB_AC_2_30020	Motor Running
MB_AC_2_30021	Emergency Stop
MB_AC_2_30022	CO Monitor Active
MB_AC_2_30023	SurgeWatch Motor
MB_AC_2_30024	Surge Count
MB_AC_2_30025	Surge Control Point
MB_AC_2_30026	Inlet Postion
MB_AC_2_30027	Blow Off Position
MB_AC_3_30001	System Pressure
MB_AC_3_30002	Discharge Pressure
MB_AC_3_30003	3rd Stage Temp
MB_AC_3_30004	1st Stage Vibration
MB_AC_3_30005	2nd Stage Vibration
MB_AC_3_30006	3rd Stage Vibration
MB_AC_3_30007	4th Stage Vibration
MB_AC_3_30008	Oil Pressure
MB_AC_3_30009	OIl Press B4 Filter

NAME	DESCRIPTION
MB_AC_3_30010	Oil Filter DP
MB_AC_3_30011	Oil Temp
MB_AC_3_30012	Oil Reservoir Normal
MB_AC_3_30013	Stator A Temp
MB_AC_3_30014	Stator B Temp
MB_AC_3_30015	Stator C Temp
MB_AC_3_30016	INBD Mtr Brg Temp
MB_AC_3_30017	OUTBD Mtr Brg Temp
MB_AC_3_30018	Motor Current
MB_AC_3_30019	System Flow
MB_AC_3_30020	Motor Running
MB_AC_3_30021	Emergency Stop
MB_AC_3_30022	CO Monitor
MB_AC_3_30023	Surge Motor
MB_AC_3_30024	Surge Count
MB_AC_3_30025	Surge Ctrl Point
MB_AC_3_30026	Inlet Vane Position
MB_AC_3_30027	Blow Off Position
MB_AC_4_30001	System Pressure
MB_AC_4_30002	Discharge Pressure
MB_AC_4_30003	3rd Stage Temp
MB_AC_4_30004	1st Stage Vibration
MB_AC_4_30005	2nd Stage Vibration
MB_AC_4_30006	3rd Stage Vibration
MB_AC_4_30007	4th Stage Vibration
MB_AC_4_30008	Oil Pressure
MB_AC_4_30009	Oil Press B4 Filter
MB_AC_4_30010	Oil Press DP
MB_AC_4_30011	Oil Temp
MB_AC_4_30012	Oil Reservoir Normal
MB_AC_4_30013	Stator A Temp
MB_AC_4_30014	Stator B Temp
MB_AC_4_30015	Stator C Temp
MB_AC_4_30016	INBD Mtr Brg Temp
MB_AC_4_30017	OUTBD Mtr Brg Temp
MB_AC_4_30018	Motor Current
MB_AC_4_30019	System Flow
MB_AC_4_30020	Motor Running
MB_AC_4_30021	Emergency Stop
MB_AC_4_30022	CO Monitor
MB_AC_4_30023	Surge Motor
MB_AC_4_30024	Surge Count
MB_AC_4_30025	Surge Control Point
MB_AC_4_30026	Inlet Vane Position
MB_AC_4_30027	Blow Off Position
MB_AC_5_33003	Analog Input #1\$(Not Used)

NAME	DESCRIPTION
MB_AC_5_33005	Analog Input #2\$(Not Used)
MB_AC_5_33007	Analog Input #3\$(System Pressure)
MB_AC_5_33009	Analog Input #4\$(Oil Pressure)
MB_AC_5_33011	Analog Input #5\$(Lube Oil Temp)
MB_AC_5_33013	Analog Input #6\$(Not Used)
MB_AC_5_33015	Analog Input #7\$(Air Temp Stg 1)
MB_AC_5_33017	Analog Input #8\$(Vibration Stg 1)
MB_AC_5_33019	Analog Input #9\$(Discharge Pressure)
MB_AC_5_33021	Analog Input #10\$(Air Temp Stg 2)
MB_AC_5_33023	Analog Input #11\$(Vibration Stg 2)
MB_AC_5_33025	Analog Input #12\$(Disch Press Stg #2)
MB_AC_5_33027	Analog Input #13
MB_AC_5_33029	Analog Input #14\$(Vibration Stg 3)
MB_AC_5_33031	Analog Input #15\$(Disch Press Stg #2)
MB_AC_5_33033	Analog Input #16
MB_AC_5_33035	Analog Input #17
MB_AC_5_33037	Analog Input #18
MB_AC_5_33039	Analog Input #19
MB_AC_5_33041	Analog Input #20
MB_AC_5_33043	Analog Input #21
MB_AC_5_33045	Analog Input #22
MB_AC_5_33047	Analog Input #23
MB_AC_5_33049	CT Input
MB_AC_5_43053	Analog Output #1
MB_AC_5_43055	Analog Output #2
MB_AC_5_43057	Analog Output #3
MB_AC_5_43059	Analog Output #4
MB_AC_5_43267	Motor Current
MB_AC_5_43269	Pressure Setpoint
MB_AC_5_43283	Inlet Valve\$NUnload Postion
MB_AC_5_43297	Power on HOURS
MB_AC_5_43299	Running Hours
MB_AC_5_43301	Loaded Hours
MB_AC_5_43303	Number of Starts
MB_AC_6_30001	
MB_AC_6_30002	
MB_AC_6_30003	Discharge Pressure
MB_AC_6_30004	2nd Stg Inlet Press
MB_AC_6_30005	2nd Stg Outlet Press
MB_AC_6_30006	Inlet Vacuum
MB_AC_6_30007	Oil Filter DP
MB_AC_6_30008	Bearing Oil Press
MB_AC_6_30009	2nd Stg Inlet Temp
MB_AC_6_30010	1st Stg Disch Temp
MB_AC_6_30011	2nd Stg Disch Temp
MB_AC_6_30012	Bearing Oil Temp

NAME	DESCRIPTION
MB_AC_6_30013	Package Disch Temp
MB_AC_6_30019	1st Stg Inlet Temp
MB_AC_6_30020	Percent Capacity
MB_AC_6_30022	Blower Speed
MB_AC_6_30025	Motor Speed
MB_AC_6_30026	Motor Current
MB_AC_6_30027	Input Voltage
MB_AC_6_30028	DC Bus Voltage
MB_AC_6_30029	Remote Pressure
MB_AC_6_30030	Motor Voltage
MB_AC_6_30031	KW Usage
MB_AC_6_30032	KW Hours
MB_AC_6_30033	KW Hours
MB_AC_6_30033zz	KW Hours
MB_AC_6_30034	Motor KW
MB_AC_6_30035	
MNTH_DATE_REAL_PEAKx	MONTH TO DATE REAL PEAK
MODE_FREEZE_TMR_2	
MODE_FREEZE_TMR_3	
MODE_HIGH_TMR_1	
MODE_HIGH_TMR_2	
MODE_HIGH_TMR_3	
MODE_HIHI_TMR_2	
MODE_HIHI_TMR_3	
MODE_LOLO_TMR_1	
MODE_LOW_TMR_1	
MODE_LOW_TMR_2	
MODE_LOW_TMR_3	
MODE_MED_TMR_1	
MODE_MED_TMR_2	
MODE_MED_TMR_3	
MUL_01	
MUL_02	
MUL_03	
MUL_04	
MUL_05	
MUL_06	
MUL_07	
MUL_08	
MUL_09	
MUL_10	
MUL_11	
MUL_12	
MUL_13	
MUL_14	
MUL_15	

NAME	DESCRIPTION
MUL_16	
Nirvana_ON	Nirvana On\$NDELAYED
Nirvana_ON_Dly	
OSRI_01	
OSRI_03	
REAL_SHLDR_PEAKx	MONTH TO DATE REAL SHOULDER PEAK
RESET_MODE	
SEL_01	
SEL_02	
SEL_03	
SEL_03	CTG1 GAS FLOW (KSCFH)
SEL_04	
SEL_05	
SEL_06	
SEL_07	
SEL_08	
SEL_09	
SEL_10	
SEL_11	
SEL_11	BOILER 4 GAS FLOW (KSCFH)
SEL_12	
SEL_13	
SEL_14	
SEL_15	
SEL_15	BOILER 4 OIL FLOW GPM
SEL_16	
SEL_16	BOILER 4 STEAM FLOW (KPPH)
SEL_17	
SEL_17	BOILER 4 FEEDWATER FLOW\$NKPPH
SEL_18	
SEL_19	
SEL_20	
SEL_21	
SEL_22	
SEL_23	
SEL_24	
SEL_25	
SEL_26	
SEL_27	
SEL_28	
SEL_29	
SEL_30	
SEL_31	
SEL_32	
SEL_33	
SEL_34	

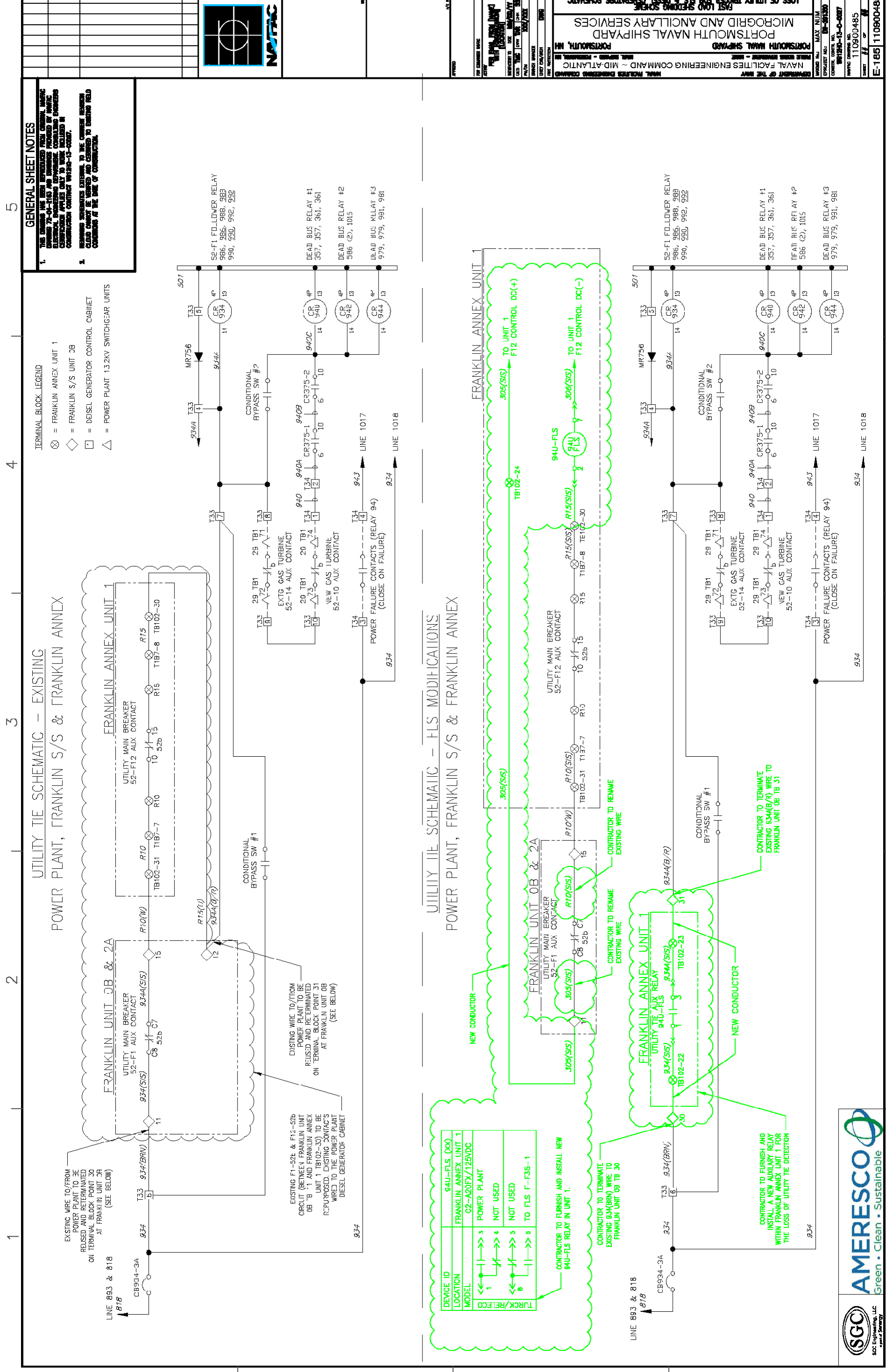
NAME	DESCRIPTION
SEL_35	
SEL_36	
SEL_37	
SEL_37	BOILER 3 GAS FLOW (KSCFH)
SEL_38	
SEL_38	BOILER 3 OIL FLOW GPM
SEL_39	
SEL_39	CTG2 GAS FLOW (KSCFM)
SEL_40	CTG2 OIL FLOW GPM
SEL_40	CTG2 OIL FLOW GPM
SEL_41	
SEL_41	BOILER 3 STEAM FLOW (KPPH)
SEL_42	
SEL_42	BOILER 3 FEEDWATER FLOW\$NKPPH
SEL_43	HRSG1 GAS FLOW
SEL_43	HRSG1 GAS FLOW (KSCFH)
SEL_44	
SEL_44	HRSG 1 STEAM FLOW (KPPH)
SEL_45	
SEL_45	HRSG1 FEEDWATER FLOW\$NKPPH
SEL_46	
SEL_46	HRSG2 GAS FLOW (KSCFH)
SEL_47	
SEL_47	HRSG2 OIL FLOW GPM
SEL_48	
SEL_48	HRSG 2 STEAM FLOW (KPPH)
SEL_49	
SEL_49	HRSG2 FEEDWATER FLOW\$NKPPH
SEL_50	
SEL_51	
SEL_52	
SEL_53	
SEL_54	
SEL_55	
SEL_56	
SEL_57	
SEL_58	
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SEL_62	
SEL_63	
SEL_64	
SEL_65	
SEL_66	
SEL_67	

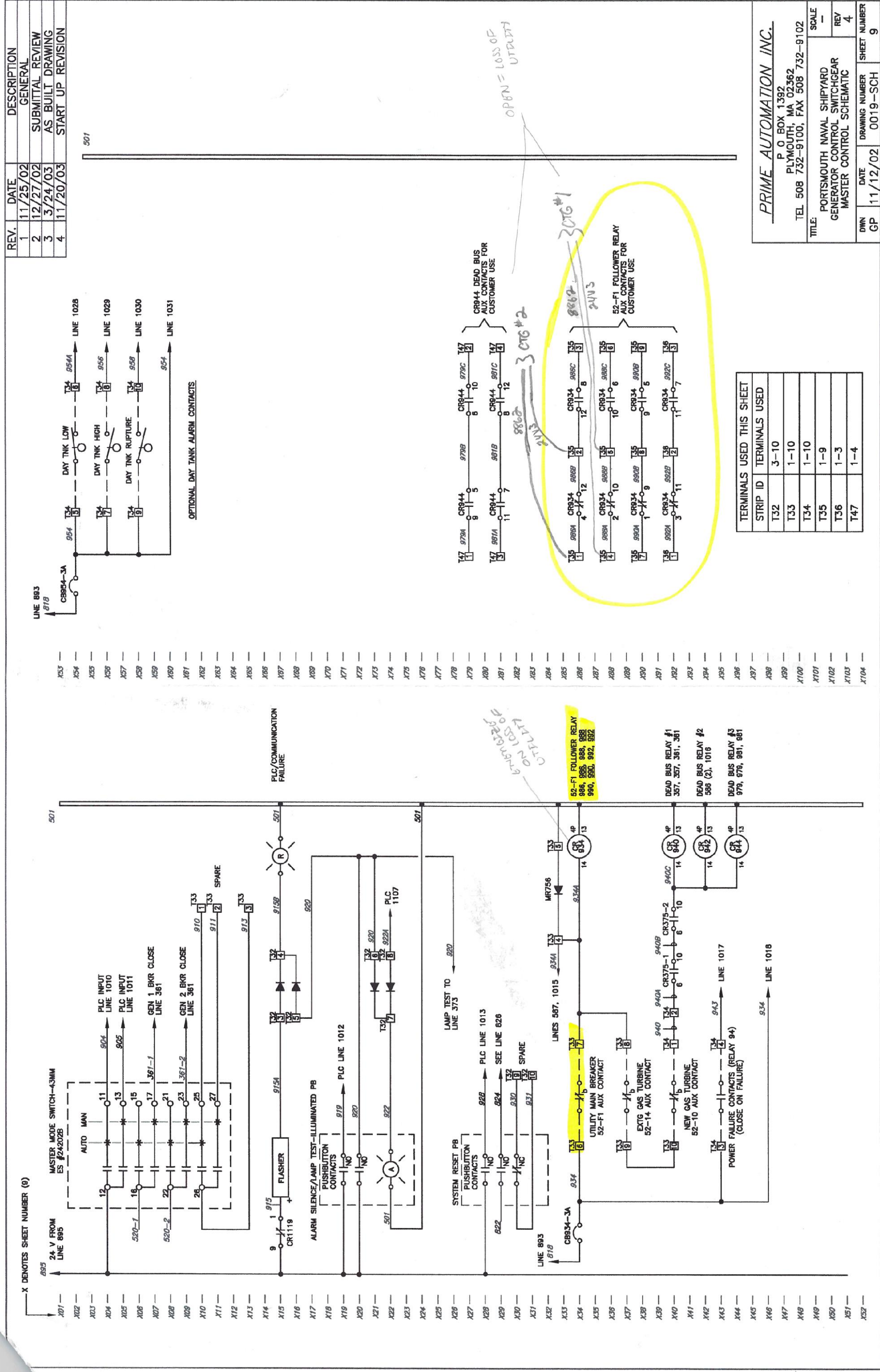
NAME	DESCRIPTION
SEL_68	
SEL_69	
SEL_70	
SEL_71	
SEL_72	
SEL_73	
SEL_74	
SEL_75	
SEL_76	
SEL_77	
SEL_78	
SEL_79	
SEL_80	
SEL_81	
SEL_82	
SEL_83	
SEL_84	
SEL_85	
SEL_86	
SEL_87	
SQR_02	
SSUM_01	
SSUM_02	
SSUM_03	
SSUM_04	
SSUM_05	
SSUM_06	
SSUM_07	
SSUM_08	
SSUM_09	
SSUM_10	
SSUM_11	
SSUM_12	
SSUM_13	
SSUM_14	
SSUM_15	
SSUM_16	
SUB_01	
SUB_02	
SUB_03	
SUB_04	
SUB_05	
TONR_01	
TONR_02	
TONR_03	
TONR_04	

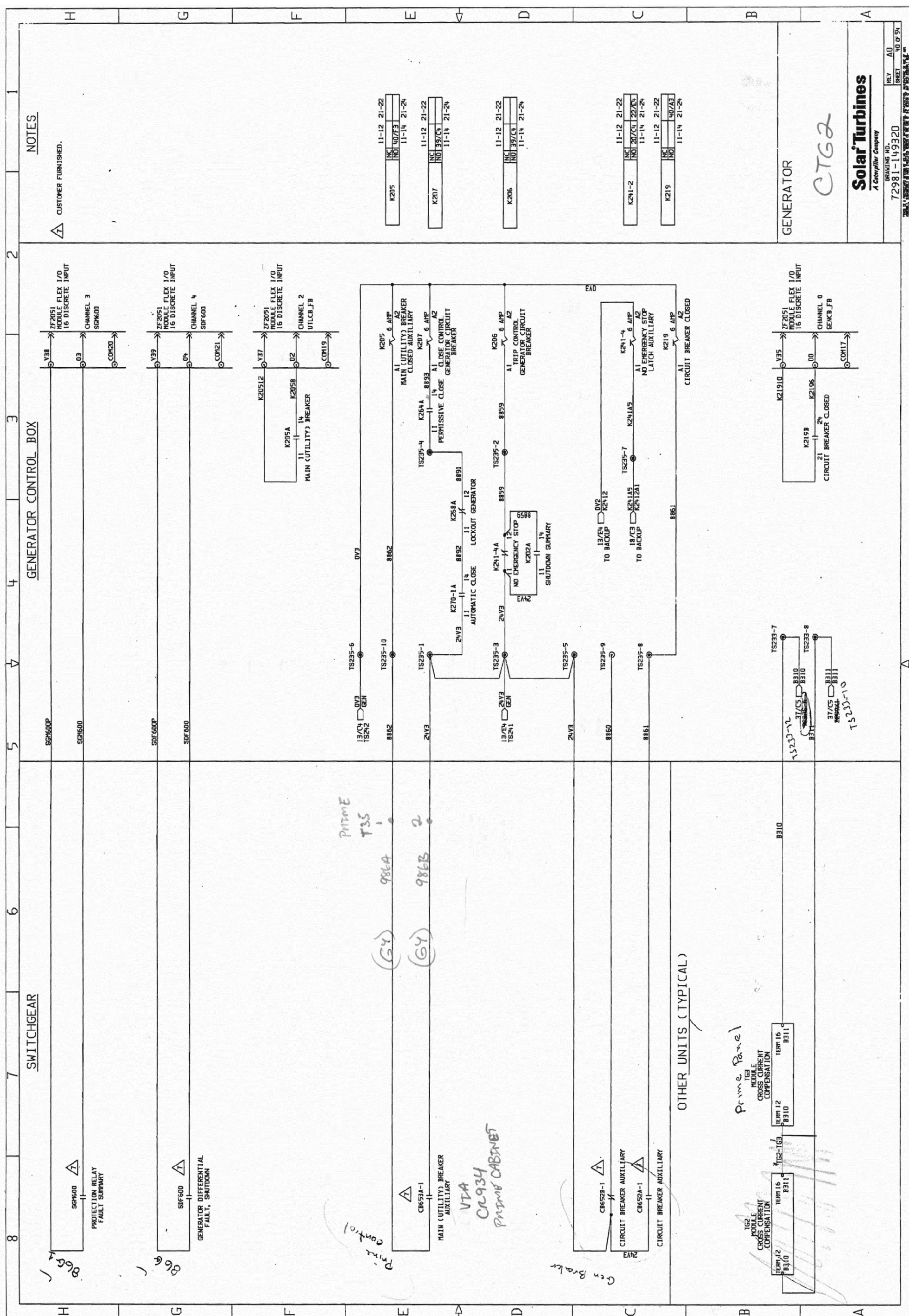
NAME	DESCRIPTION
TONR_05	
TOT_01	
TOT_03	
TOT_04	
TOT_06	
TOT_07	
Write_Centec_SP_Delay	
Write_Nirvana_SP_Delay	
Write_SP_Delay	
ROUTINE	COMMENT
AIR_COMPS_MODES	Next two (2) rungs change from HIGH to Freeze
AIR_COMPS_MODES	Next two (2) rungs change from MED up to HIGH, or Freeze down to High
AIR_COMPS_MODES	Next two (2) rungs change from HIGH down to MED, or from LOW up to MED
AIR_COMPS_MODES	Next two (2) rungs change from MED down to LOW, or from LOLO up to LOW
AIR_COMPS_MODES	Next two (2) rungs change from LOW down to LOLO
AIR_COMP_5	Next two (2) Rungs set the load and unload status of Compressor #5
BLR3_COMMS	Checking for differences in number of times the message command is enable
BLR4_COMMS	Checking for differences in number of times the message command is enable
CTG_1_COMMS	Checking for differences in number of times the message command is enable
CTG_2_COMMS	Checking for differences in number of times the message command is enable
DG_COMMS	DIESEL DAY TANK COMMUNICATIONS\$NIP ADDRESS 192.168.2.134
DG_COMMS	Checking for differences in number of times the message command is enable
FM_400_800_TOT	THIS RUNG SCALES THE PULSES. FM4001_EVER_PULSES COUNTS ONLY THE P
FM_400_800_TOT	THIS RUNG SCALES THE PULSES. FM8001_EVER_PULSES COUNTS ONLY THE P
HRSG1_COMMS	PUT IN TO COUNT DONE ON MSG COMMANDS DISABLED NORMALLY REMOV
HRSG1_COMMS	HRSG1 LOCAL SLC PLC REGISTER N7:26 IS 0 - 16383 COUNTS WHICH EQUALS (
HRSG1_COMMS	Checking for differences in number of times the message command is enable
HRSG2_COMMS	Checking for differences in number of times the message command is enable
PM_COMMS	CTG2-KW IS READ FROM THE POWER MONITOR. THE COMMUNICATIONS HA
PM_COMMS	THIS RUNG IS PART OF ABOVE RUNG. SINCE CTG2_KW IS USD THROUGHOUT
PM_COMMS	Checking for differences in number of times the message command is enable
PNS_POWER	CTG1 COST OF POWER STARTS HERE
PNS_POWER	CTG1 COST OF POWER STARTS HERE
Power_Status	THE FOLLOWING TWO RUNGS GIVE NUMERIC VALUES TO THE DAY OF THE W
Power_Status	LOOK AT DATE (OFF-PEAK) : IF THE DAY OF THE WEEK IS SATURDAY OR SUND
Power_Status	LOOK AT DAY (OFF-PEAK) : IF THE TIME IS BETWEEN 20:00 AND 23:59 HOURS
Power_Status	LOOK AT DATE (SHOULDER) : IF THE DAY OF THE WEEK IS SATURDAY OR SUND
Power_Status	LOOK AT DAY (SHOULDER) : IF THE DAY OF THE WEEK IS NOT SATURDAY OR S

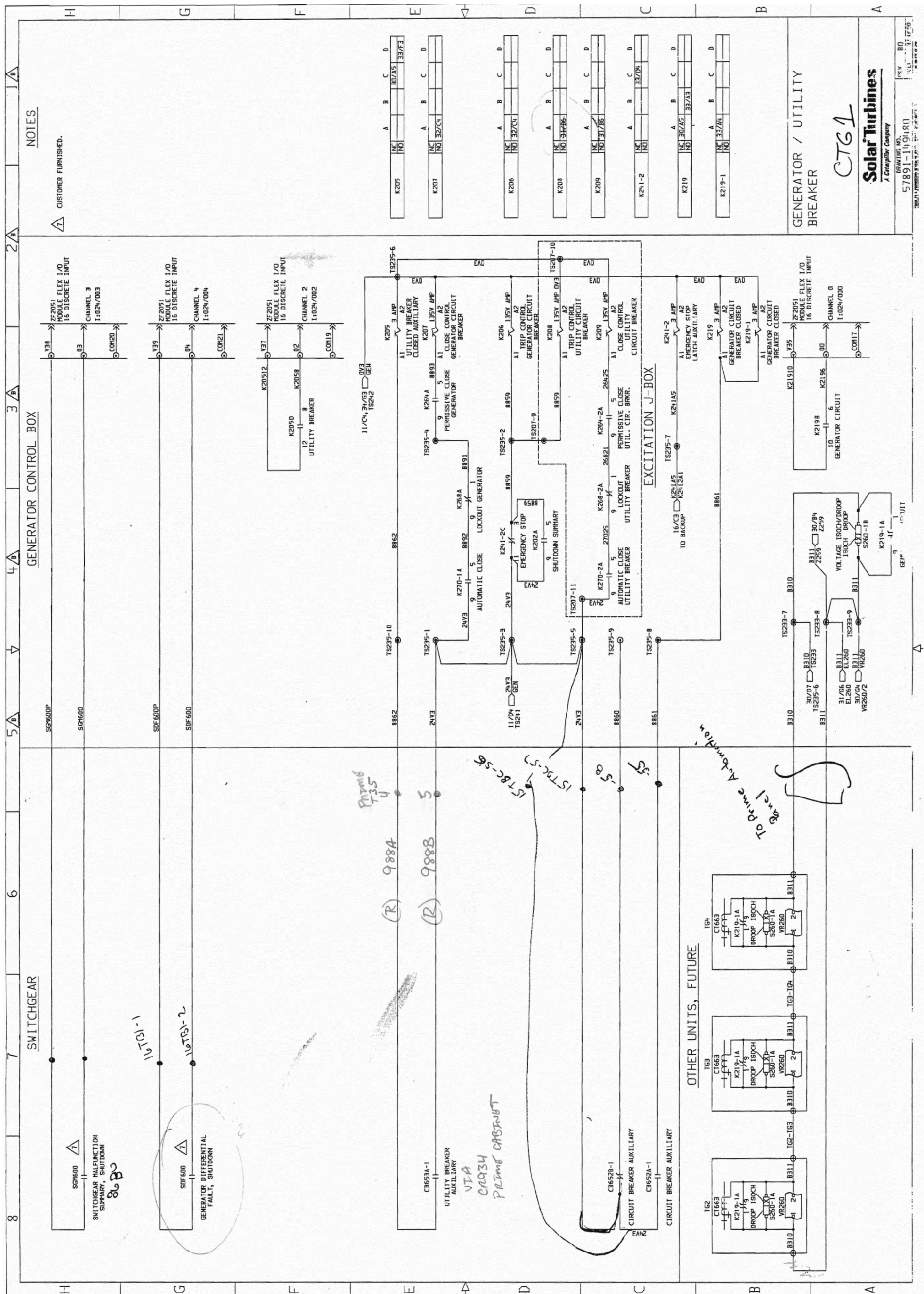
12. Appendix A. Associated Drawings











**APPENDIX L - IEEE WHITE PAPER:
“EXPERIENCE WITH FAST LOAD SHEDDING USING
IEC 61850 GOOSE”**

EXPERIENCE WITH FAST LOAD SHEDDING USING IEC 61850 GOOSE

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Abstract – Load shedding is critical for facilities that have co-generation capability to prevent collapse of the cogeneration assets. Fast load shedding requires sub-cycle speed to manage thousands of distributed loads within a facility. This paper describes the experience with applying such a fast load shedding scheme across a wide array of relays. The system described in this paper utilizes a proven fast load shed system and makes it easy to configure larger and more complex load shed schemes. The paper proposes the architecture of a central fast load shed controller interfaced with local feeder protection relays over IEC 61850 GOOSE. One of the challenges with a large-scale load shed scheme deployment is configuration of devices, and especially the IEC 61850 GOOSE engineering process which may add further complexity. This paper proposes a simple to configure IEC 61850 GOOSE scheme with high-speed performance requirements. Lessons learned from the fast load shed deployment are also discussed.

Index Terms — Fast Load Shed (FLS), GOOSE (Generic Object Oriented Substation Event), VLAN (Virtual Local Area Network), Quality of Service (QoS), Fast Load Shed Controller (FLSC), Fast Load Shed Aggregator (FLSA), IED (Intelligent Electronic Device), Rate of Change of Frequency (ROCOF), HMI (Human Machine Interface), DCS (Distributed Control System).

I. INTRODUCTION

Industrial facilities, such as petrochemical, oil & gas, pulp and paper mills and refineries, often rely on on-site generation. When an imbalance exists between the load, and the available generation due to loss of generation/utility supply, the frequency of the system will decay as the local generators begin to slow down due to the excessive load. As the frequency decays, the efficiency of the generators is affected and the ability to run the generator auxiliary system can also contribute to the problem. The frequency decay in industrial power systems with cogeneration is much faster than in traditional transmission systems. If load isn't rapidly removed from the system, a cascading effect could occur and the whole system could collapse. Fast Load Shed (FLS) is a special protection scheme

that, in a contingency, initiates shedding of loads as required to preserve system load/generation balance thereby avoiding this complete system collapse. A contingency is the loss of one or more infeeds (local generators or incomers from the local grid). Unlike traditional under voltage, under frequency or frequency rate of change load shedding schemes, a fast load shedding scheme can initiate load shedding before the system frequency or system voltage declines significantly. The ability to shed load before the system frequency starts to decay can help the system maintain its stability. Less critical loads are shed so that more critical loads are maintained, and the industrial process suffers the minimum impact possible.

II. IEC 61850 FAST LOAD SHED ARCHITECTURE

Fast Load Shed (FLS) is a system consisting of one controller, zero or multiple aggregators (if more than 64 infeeds and loads must be monitored), an Ethernet network and IEC 61850-8-1-capable end devices to provide fast load shedding including breaker tripping. The goal of the FLS is to re-establish power balance when source/load balance is disrupted. End devices are protective relays or meters with IEC 61850-8-1 GOOSE support. This means that the end-device must be capable to transmit analog and digital values via IEC 61850 GOOSE.

The FLS system is a scalable architecture that can expand as the industrial facility grows and changes. The system is comprised of a main FLS controller and aggregators. A system overview and communications architecture of the FLS is shown in Figure 1.

The Fast Load Shed Controller (FLSC) is the main decision point of the system where all the calculations and intelligent commands are performed. It is a substation-hardened device with a real-time operating system that is highly reliable and accurate. The controller is informed of present system power flows and of contingencies (active power value and offline status) via data messages received from end devices, aggregators or both via analog/digital IEC 61850 GOOSE, of each data unit (infeeds and load groups). It is capable to handle up to 32 loads/load groups and 32 sources/infeeds, and makes the final decision to shed load in real time. The load shed commands are issued via IEC 61850 GOOSE messages to end devices.

The Fast Load Shed Aggregator (FLSA) is an extension of the FLSC allowing for aggregation of load data and is a load shed data concentrator. It combines load data from end devices and sends this data as analog/digital IEC 61850 GOOSE to the FLSC. The aggregator or FLSA does not make load shed decisions. It merely allows the FLS controller (FLSC) to handle more than 64 infeeds and loads. Each FLSA supports 64 data units end devices and up to 32 load groups. Note: FLSA supports only load data units and not infeeds. Infeeds must be configured directly to the FLSC. By connecting the aggregators in a tree-like matrix, the number of loads controlled with this scheme can reach over 2500.

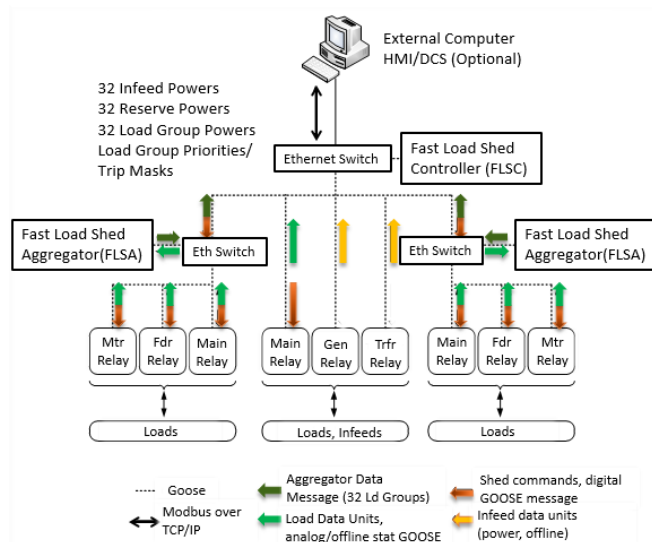


Fig. 1 – Typical FLS Scheme Communications

An FLSC is configured to shed load groups in the event of a contingency according to a set of priorities or trip masks. For the purposes described here, a contingency is the loss of any one or more infeeds or a pre-defined scenario. A load group is a number of individual loads that are treated by the fast load shedding scheme as a single unit, allowing the FLSC to handle thousands of individual loads with a manageable number of settings. The information received by a FLSC or by FLSA in a data message about a load, an infeed or an aggregator is referred to as a data unit.

Based on settings, on the information in data units, and on the present priorities or trip masks values, the FLSC generates shed requests indicating which load groups are required to be shed by the end devices. The shed requests are transmitted to the end devices in a shed command message and the end devices do the actual breaker tripping.

The FLS system is expandable. The addition of another aggregator or FLSA connected to the FLSC extends the system by an additional 64 end devices and up to 32 load groups. With 12 infeeds, 18 loads and 40 aggregators (64 loads each), the system can support 12 infeeds and 2578 shed-able loads. Minimal re-configuration is necessary in the case of system expansion.

End devices send to an FLSC or an FLSA up to six data units in a single IEC 61850 GOOSE data message. Not all of the data units in a data message have to be used. Infeed data units

contain the measured real power flowing out of the infeed and the offline status of the infeed. Change of offline status from "Off" to "On" is an indication of the loss or eminent loss of that infeed; which is, a contingency. Load data units contain the measured real power flowing into the load and the unavailability status of the load for fast load shedding. Loads with unavailability status are not included when calculating the amount of shed-able load in a load group. Data messages with infeed data units are sent directly to the FLSC for optimized performance and cannot be transported via an FLSA.

End devices use a configurable GOOSE message to publish data from at least one and up to six infeed or load data units. Data messages with infeed data units use fast transmission configurable GOOSE messages for fastest contingency detection at the FLSC. End devices interfacing to infeeds use a configurable GOOSE to subscribe to shed commands.

FLSA's send to the FLSC (or conceivably to another higher level aggregator) a single data message. FLSA data messages contain 32 load group powers. Each load group power is the sum of the powers of the load data units that are available for shedding and are aggregated by that aggregator to that load group.

The FLSC sends back down to the end devices an individual shed request operand for each of the load groups used by the application, typically all in a single shed command. The shed commands are sent directly to all end devices via the switched Ethernet network.

The actual Fast Load Shed system under review consists of only a FLSC, 38 Data Units (11 infeeds, 18 load groups), 8 end devices that publish between 3 and 5 data units to the FLSC located at 3 substations. Some end devices publish a mix of load and infeed data units (4), where others publish only load data units (4). Since the total number of data units is less than 64 (including allowing for significant system expansion) an aggregator (FLSA) is not required. The system also has an HMI which is used to change load group priorities and the needed software to retrieve event files from end devices for system operational analysis. Communications architecture is as follows in Figure 2 and simplified single line in Figure 3. The system has 2 utility supplies from the local distribution utility, 2 gas turbines (5 MW each) and 2 diesel generators (1.8 MW each) and a battery back-up system (500 kW) installed at the power plant. Normally at least one of the gas turbines will be operational, however the diesel generators are synchronized only during islanded conditions or during testing. Total system load varied around 8 to 12 MW. Shedable loads are at the power plant and substation 2. In this scheme, some loads are automatically shed during an islanding condition since their data was not integrated into this phase of the fast load shed implementation.

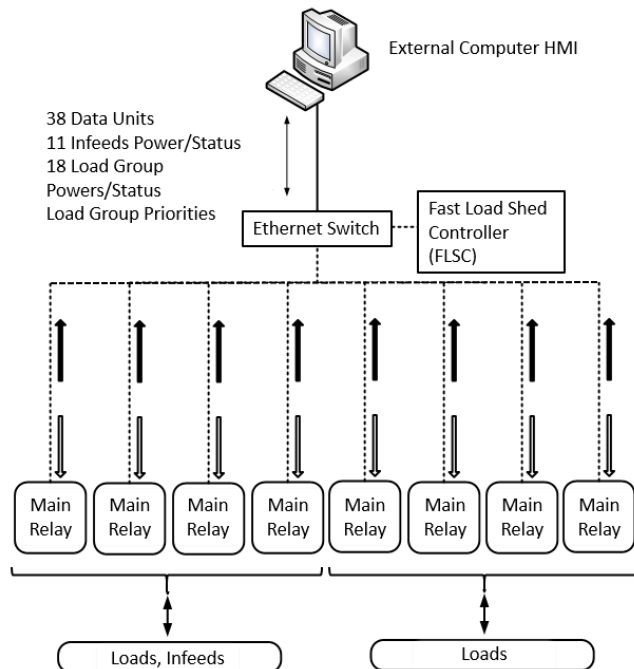


Fig. 2 – Actual FLS Scheme Communications

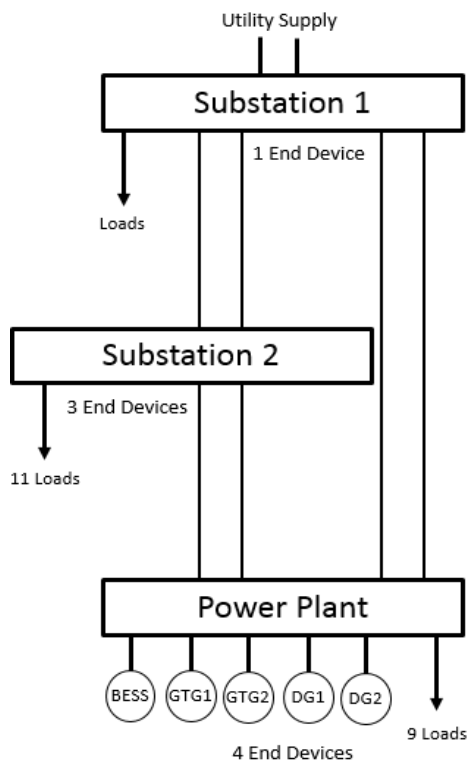


Fig. 3 – Simplified System Single Line

III. DYNAMIC SOURCE/LOAD POWER BALANCING

The physics of electrical systems forces the sum of the real power generated by local generation and the real power

imported/exported from the grid to precisely equal the sum of the real power consumed by the loads, always and at every instant. If a local generator is tripped, or a grid incomer is lost, the physics forces additional power to be drawn from the remaining grid incomers and local generators to match the load. Increased power flow through an incomer can overload it, causing it to trip and leading to cascading tripping and total collapse of the distribution system. Increased power flow out of a generator can cause it to slow down, and if the prime mover cannot provide additional mechanical power rapidly enough, lead to frequency collapse of the industrial distribution system.

The reviewed Fast Load Shed system triggers only if the grid incomer is lost, hence excess load will slow remaining generators down and cause a system collapse if load is not tripped rapidly.

When a contingency operation is triggered (either by a loss of an infeed or a programmed scenario), the fast load shed controller checks if grid incomer lost exceeds remaining generation reserve. If this situation occurs, then load shedding is performed.

The FLSC continuously calculates the load available for shedding in each load group. This value is the sum of the power of all data units that are mapped to the load group and have unavailability for shedding status false, plus the sum of the corresponding power values of all aggregator data units.

Using the power values of data units mapped to infeeds and various infeed settings, the FLS scheme estimates the amount of additional power (that is, reserve power) each infeed can deliver in event of a contingency. Depending on the settings, the estimation can be either based on the infeed being able to immediately jump to its maximum power, or its increase being some fraction of its present power.

The steady state value of the load, infeed and reserve is estimated using the average of each of these quantities over a 10 second period. Analog values from the infeeds and load groups are typically communicated once per second to the FLSC. These steady state values are latched (frozen) when a contingency is first declared, and the latched values are used until the contingency is over and the power system is assumed to have reached a new steady state. This allows the FLSC to achieve a steady state load/infeed balance. Instantaneous measurement values leading up to and during the contingency may contain unsustainable transients. For instance, should an incomer open at the utility's end, and the FLSC see its power as zero when the offline status becomes true, the estimate of power lost would be zero were instantaneous power measurements used.

A contingency is declared when any infeed is lost or when any programmed scenarios occurs. An infeed is deemed lost when its offline status transitions from "Off" to "On", other than due to loss of communications. A programmed scenario is deemed to have occurred when its scenario operand transitions from "Off" to "On".

Both the infeed lost condition and the programmed scenario occurred conditions are latched until the end of the contingency. Each time an infeed is initially lost or a programmed scenario initially occurs, the contingency timer is triggered or re-triggered. The contingency lasts until the contingency timer finally times out. The contingency timer has a dropout setting intended to be set long enough that on timeout the power system should be in a new stable state.

The FLSC moment-by-moment calculates the amount of load shedding required, which is called the load shed value. A load shed value is continuously calculated as the sum of the steady state values of all lost infeed powers, less the sum of the steady-state reserves of all infeeds not lost. The load shed value is the amount of load shedding required to restore the load/infeed balance. A load shed value less than zero indicates no shedding is required.

When an infeed is lost, sufficient shed requests are set and latched by the FLSC, such that the sum of the latched steady state load group load values just exceeds the load shed value. Load groups with lower priorities are shed in preference to load groups with higher priorities. Load groups with priority zero are not used, hence not shed. Load groups having the same priority are all shed when any needs to be shed. If a second infeed is lost (that is, should there be a multiple or evolving contingency), the above calculations will result in the load shed order increasing, and in general the number of shed requests also increasing.

The FLS algorithm does not need to monitor non shed-able loads. However, all infeeds whose loss can cause a significant power imbalance or that can supply significant reserve should be monitored.

For a programmed scenario, each load group's shed request operand is set and latched by the FLSC every 1 ms when one of the 32 programmed scenarios is true and the bit in that scenario's trip mask corresponding to that load group is a true. The scenario operand values are determined by user configurable logic. Each scenario's trip mask has 32 bits, one for each load group. An external computer system is typically responsible for ensuring the trip masks have the appropriate values pre-contingency, although the trip masks may also be set manually through the FLS software.

The shed requests are sent to the end devices in the shed command IEC 61850 GOOSE messages described earlier and the end devices shed the loads in the requested load groups by initiating breaker tripping. When no new infeeds have been lost and no new scenarios detected for a period of time (that is, when the contingency timer expires), the above-mentioned latches are reset, terminating the shed requests.

Change requests for priorities and trip masks and for their writable actual values received during a contingency are not implemented until the contingency is over. Implementing the update would result in both the shedding called for in the pre-update settings and the shedding called for in the updated settings being requested, which could possibly produce more load shedding than necessary.

In case of generation loss or power unbalance, IEC 61850 GOOSE messages are sent to shed enough load per pre-defined priorities above available generation reserve. Alternatively, for fixed pre-set contingencies, a predefined shedding scenario can be executed upon each defined contingency.

Load priorities can be changed or updated via a device HMI within one second. The pre-defined priorities of the load shed system basically consist of a table that defines the order in which loads should be shed. This allows the system to prioritize the loads to be shed between non-essential and essential process loads. Priorities are numbers assigned to each load group used by the FLSC on the relative importance of the load groups. The ability to change the load priorities allows the user

the flexibility of dynamically changing the priorities based on the priority of each facility processes.

Below Figure 4 is a simplified system example illustrating the load shed priorities and how shedding is determined.

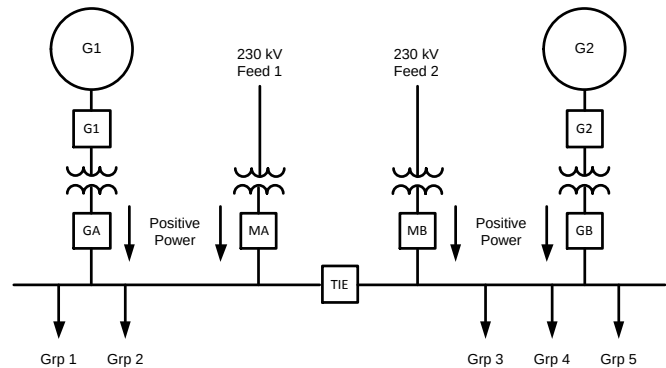


Fig. 4 – Simplified Source-Load Example

In Figure 4, the total system load equals the sum of all the system power loads (PGrp1 + PGrp2 + PGrp3 + PGrp4 + PGrp5). The total source/generation equals the sum system sources (PG1 + PG2 + PMA + PMB).

For example, if the industrial facility were to set the load group priorities shown in Table I and a loss of 9MW of generation with no generation reserve, the scheme will trip load groups 3 and 5 for a total of 10MW.

TABLE I
LOAD GROUP PRIORITIZATION FOR SIMPLIFIED
SOURCE-LOAD EXAMPLE

Asset	Value	Priority/Status (user set)
Group 1	10 MW	1 (highest priority)
Group 2	10 MW	0 (do not shed)
Group 3	5 MW	128 (lowest priority)
Group 4	20 MW	2
Group 5	5 MW	3

* Load Prioritization (as set by end-user) – higher numbers mean lower priority loads.

If the industrial facility were to set the load group priorities shown in Table I and a loss of 40 MW of generation with 15 MW of generation reserve, the scheme will trip load groups 3, 4 and 5 for a total of 30MW.

Data message monitoring of the FLSC is accomplished by maintaining a "Time-Allowed-To-Live" timer for each of the data units. This timer is reset to the "Time-Allowed-To-Live" value received in each data message containing that data unit. A loss of connection is declared if this timer ever times out, and the FLS initiates a communications trouble alarm, sets status operands to "On" and sets the data unit power value to zero in the event that communications was lost with an end-unit. The FLSC uses the values of the communications trouble alarm and the resulting change of offline status to "On" from initiating a contingency, hence ensuring no shedding due to loss of communications. Remote device off-line and or communications trouble alarm could be used to annunciate FLS scheme trouble conditions, and perhaps even to block the FLS scheme.

IV. FAST SPEED

Conventional frequency and voltage load shedding schemes operate typically in 250 ms to seconds. Contingency based load shedding schemes are typically faster at 160 to 400 ms depending on both system architecture and communications employed. Both these scheme types are too slow for industrial cogeneration applications, such as pulp and paper mills and refineries, where very fast load shedding is required to ensure power system and critical processes integrity.

The speed of fast load shedding including internal processing or execution time is shown in Table II, which illustrates the FLS system quickly executes in less than 20 ms. The total operating time of the FLS must include the end load device breaker operating time which is typically 3-5 cycles for a medium voltage industrial feeder breaker. Thus, the total operating time of the FLS scheme shown in Table II is approximately 100 ms.

TABLE II
EXAMPLE OF TYPICAL FAST LOAD SHED TIMING

Time	Event
t = 0	End device detects trip/breaker operation
3 ms	GOOSE message with change of online state sent by end device (3 ms)
3.2 ms	GOOSE message passed through multiple LAN Ethernet switches (0.2 ms)
6.2 ms	FLSC processing and calculations from received GOOSE message (3 ms)
7.2 ms	Shed command GOOSE message composed by FLSC (1 ms)
7.7 ms	FLSC GOOSE message is sent through LAN Ethernet switches (0.5 ms)
10.7 ms	Shed command GOOSE message parsed by end load devices (3 ms)
14.7 ms	End load device calculations and processing (4 ms)
16.7 ms	Trip contact output closes on end load devices (2 ms)
16.7 ms	Total FLS execution time
67-100 ms	End device load breakers open (3-5 cycle breaker)

Table III shows some test results from a fast load shed scheme operation in conjunction with backup df/dt (ROCOF – rate of change of frequency) and under frequency load shedding, illustrating operating speed of each system at a petrochemical facility that was islanded as a 4.5MW underpowered island. In this case, the FLS scheme operated in 13 ms, including trip command to shedding load breakers. The total scheme operating time of the FLS scheme including the end load device breaker operating time (3 cycles for a medium voltage industrial feeder breaker) is 63 ms. In this situation, rate of change of frequency and underfrequency would have operated some time later than the FLS scheme.

TABLE III
ACTUAL FAST LOAD SHED PERFORMANCE RESULTS

Time	Event
0 ms	Utility Breaker opened by protection
2 ms	Breaker status open after de-bounced, island detected (1.05MW under generation), priorities 32, 18, 17,16, 15, 14 and 12 load group shed sent by FLSC (1.148MW)
13 ms	Shed command message received at load devices
15 ms	Trip coils energized
46 ms	Shed breaker open – load disconnected (Breaker time 31ms) by FLS scheme
64 ms	ROCOF (df/dt) trigger (typical)
106 ms	Under frequency load shed trigger (typical)

* Refer to Figure 4 for one-line diagram

V. LESSONS LEARNED

During system installation, testing, commissioning and actual system operations, various aspects were observed of the FLS system and end-device configurations and hence improvements/changes were implemented. Some of these include the following:

A. TESTING

Testing of the fast load shed scheme occurred during a factory acceptance testing (FAT), site acceptance testing (SAT) and commissioning. The challenge with FAT and sometimes SAT is that not all end devices might be available, or its settings might not be finalized. Live system testing was performed during commissioning, first while the system was isolated from actual tripping (blocking switches were open), and then actual live system islanding operations, during an over-generated islanding condition (proving non-operation of the FLS system), and then during an under-generated islanding condition (proving correct scheme operation, shedding of load and maintaining of the local power system).

Each contingency that could affect the initialization of the scheme, was tested live to prove correct scheme initialization.

All testing was executed with a very detailed test plan since 3 teams were required at 3 different locations.

B. SCHEME INITIALIZATION

During live activation and monitoring of the system over the demonstration period it was discovered that activating all infeeds including the gas turbines and diesel generators as initiators had an undesired outcome. The undesired result, was that an inadvertent shedding of load took place during the monthly cycling of an emergency diesel generator while on its maintenance run.

FLS initialization was changed to ensure the scheme can only be initialized upon islanding of the industrial system via the grid incomer.

C. POST-OPERATION ANALYSIS/CHALLENGES

After actual FLS scheme operations when the Industrial plant lost its connection to the local utility grid (due to a system fault on the utility-side), trouble shooting was challenging due to the following:

1) EVENT REPORT ANALYSIS

The FLSC did trigger and capture a detailed FLS report, sequence of events report (SOE) and end devices did trigger all SOE but not all waveforms, however not all end device functionalities were visible in the SOE and waveforms captured. Some functions such as contact inputs and outputs events where not enabled in a few end devices; which made tracking when some load breakers that got tripped and then opened during the fast load shed event, hard to identify.

Some end devices did not trigger waveform capture, and this did not include all needed channels, eg. it is essential to have all powers assigned as analog channels, shed commands, breakers trip and open indications assigned to waveform capture. Furthermore, it was necessary to change some of the waveform triggering logic to ensure waveforms are always triggered during a FLS event.

SOE and waveform reports were not used during all system testing, which is recommended to be used and reviewed during any P&C commissioning or maintenance testing.

2) TIME SYNCHRONIZATION

All end devices and the FLSC were time-synchronized via SNTP from the HMI, however daylight savings time was not correctly implemented in all end devices, and corrected.

Using SNTP is sufficient, however this can still have a time discrepancy of 10ms, which must be considered during system event analysis. Irig-B or PTP would be a better choice as means for time synchronization.

3) DISABLE/RESET OF FLS SCHEME

Initially, the FLS scheme could be enabled/disabled only from the HMI. The danger with this scenario is that the scheme can't be easily disabled if communications is lost between the HMI and FLSC. A local control push button on one of the end devices near the control room was assigned to allow local disabling of the scheme.

Resetting of each trip signal that tripped the load breakers during a shedding event was initially on a per-breaker basis from the HMI. This was enhanced to allow one global reset command to reset all trip signals. These trip signals are latched and reside in the end devices, not the FLSC to ensure signals will be maintained even during the loss of communications.

4) LOCAL GENERATOR PROTECTION COORDINATION

In some of the events where a system fault occurred, the fault was on the distribution feeder (utility supply) in excess of 0.6 seconds before the local system got islanded and distribution feeder tripped. The local generator protection of the gas turbine did unfortunately also operate for this system fault at about the same time the FLS system shed the needed load; so, in this case the whole system was lost. The FLS system did operate

in about 15ms and some load breakers opened around 46ms after the system got islanded, however with such a long occurring feeder fault, the generator protection operated too.

Proper protection coordination between the feeder protection (utility supply) and local generator protection thus needs to be re-evaluated.

Further analysis pointed out that during some utility supply faults external to the local system, islanding would not take place until the under voltage (ANSI 27) operated at the point of common coupling (PCC). This typically could only pick up if the local generation did collapse too, meaning that local generation is lost when the fast load shed gets initiated; consequently, will the local system be lost. During one of the system fault events, the fault was very close to the PCC (on the utility side) and the neutral over voltage (59N) did operate much quicker. During this event the local generation was maintained; the fast load shed operated and the local system did stabilize as an island.

To rectify the under voltage (27) dilemma, transfer tripping from the utility-end to the PCC is explored to ensure much quicker islanding during a system (utility) feeder fault.

5) USE OF SYNCHROPHASORS

During an actual FLS event, some of the dynamic changes in the local system, such as frequency and voltages, could only be observed at the update capabilities of the end devices; and doesn't show the fast-dynamic response needed for detailed analysis, especially the frequency response.

Synchrophasors or the measurements and monitoring of fast changing voltage and frequency is recommended to be used to enhance system analysis and observation capabilities. This would allow to monitor system stability performance, to determine system stability limits.

VI. ENHANCEMENTS OVER TRADITIONAL SYSTEMS

The fast load shed scheme offers many benefits over traditional systems beyond its speed improvements. Additional enhancements include: future proof (the scheme is based on universal communications protocols and architectures used by multiple vendors), reduction of hardware, redundancy for added security and utilization of existing Ethernet networks.

Hardware can be reduced because additional transducers are unnecessary since existing IEDs are used and they utilize the existing current and voltage transformer circuits and measurement algorithms. Additionally, since the information is sent as a GOOSE message over the existing Ethernet network, the wiring associated with the transduced signals is eliminated. The reduction in wiring not only simplifies this architecture, but it also gives the system the ability to be much larger with more measured loads. It would become very difficult to accommodate and manage a large system with wired transduced signals. When these signals are communicated, as in this architecture, the FLS system becomes much more manageable as it expands in loads.

PLC (programmable logic controller) based systems are unable to provide such fast operation that is achieved using IEC 61850 GOOSE messaging. In addition, PLC based schemes require significant custom programming unlike a pre-developed

algorithm within the FLS, which avoids over-shed or under-shed situations.

Since this fast load shed scheme operates based on a loss in power balance, shedding only the amount of shedable load needed to re-establish system balance, this system is much more pro-active compared to traditional systems based on voltage and/or frequency, and much more dynamic than a PLC-based system that typically shed a fixed set of loads for a specific contingency.

When industrial facilities consider an upgrade to their electrical system, it is advised to consider IEC 61850 based protective relays and meters, so these same devices can be used for protective functions, metering, data gathering and load shed. These IEDs should be designed with three phase currents and three phase voltage measurement connections, breaker/contact status, trip/start and close/stop functionality and network connectivity. With this design approach, a fast load shed scheme can be easily implemented at a minimal cost.

VII. HMI AND DCS INVOLVEMENT

Load shed priorities of the FLS may contain permanent setting values, or an external computer, or HMI (Human Machine Interface) or DCS (Distributed Control System) can be set up to continuously adjust the priorities/trip mask as required by changing process needs. These adjustments include the permission and blocking for smoothly incorporating the production process needs. Modbus RTU TCP/IP protocol is used by the external computer, HMI or DCS. Figure 2 shows the integration of an external computer with HMI communicating into the FLS scheme.

VIII. CONCLUSIONS

Fast Load shed is a necessary requirement with facilities that have co-generation capability, such as industrial, pulp and paper mills and refineries. This allows the facility to shed loads to prevent loss of the facility when the load exceeds the generation capacity through a contingency event such as loss of a utility main. The system described in this paper utilizes a proven fast load shed system that has several advantages over existing systems and makes larger more complex or more configurable load shed schemes possible.

IX. REFERENCES

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Troy Wilsey is an engineer with extensive experience in developing projects for the U.S. Department of Defense (DoD) via Energy Savings Performance Contracts (ESPC), specializing in microgrid controls, energy storage, distributed generation, and O&M.

Serving as co-principal investigator for a DoD grant demonstrating microgrid and energy storage technologies; he has been integral to the design, technology selection, grant proposal writing, and contract negotiations, as well as overseeing construction, commissioning, testing, data analysis, and reporting. The demonstration provides islanding capability to the Navy shipyard while creating a new revenue stream through participation in the ISO New England Regulation market under FERC Order 755. As of December 2015 the system has been fully commissioned and is actively operating.

He is also responsible for maintaining relationships and cross pricing technologies with industry leading energy storage manufacturers and modeling payback performance periods on candidate projects. His work supports business development efforts to build out a portfolio of systems which offer energy security, savings in utility demand charges, and revenue from electricity markets in territories such as PJM, ISO-NE, and CAISO, as well as international markets such as Canada, Central America, and the UK.

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In 1989, Mr. Gagner began his career working for the Public Works Department located at the Naval Education and Training Center, Newport, Rhode Island as an electrical power engineer. In 1992, Mr. Gagner went to work for Quad Three Group, Inc.

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APPENDIX M

FERC

18 CFR Part 35

[Docket Nos. RM16-23-000; AD16-20-000]

157 FERC ¶ 61,121
DEPARTMENT OF ENERGY
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 35

[Docket Nos. RM16-23-000; AD16-20-000]

Electric Storage Participation in Markets Operated by Regional Transmission
Organizations and Independent System Operators;

(November 17, 2016)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: The Federal Energy Regulatory Commission (Commission) is proposing to amend its regulations under the Federal Power Act (FPA) to remove barriers to the participation of electric storage resources and distributed energy resource aggregations in the capacity, energy, and ancillary service markets operated by regional transmission organizations (RTO) and independent system operators (ISO) (organized wholesale electric markets). Specifically, we propose to require each RTO and ISO to revise its tariff to (1) establish a participation model consisting of market rules that, recognizing the physical and operational characteristics of electric storage resources, accommodates their participation in the organized wholesale electric markets and (2) define distributed energy resource aggregators as a type of market participant that can participate in the organized wholesale electric markets under the participation model that best accommodates the physical and operational characteristics of its distributed energy resource aggregation. We are taking this action pursuant to our legal authority under section 206 of the FPA to

Docket Nos. RM16-23-000 and AD16-20-000

- 2 -

ensure that the RTO/ISO tariffs are just and reasonable and not unduly discriminatory or preferential.

DATES: Comments are due **[INSERT DATE 60 days after publication in the FEDERAL REGISTER]**.

ADDRESSES: Comments, identified by docket number, may be filed in the following ways:

- Electronic Filing through <http://www.ferc.gov>. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format.
- Mail/Hand Delivery: Those unable to file electronically may mail or hand-deliver comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street, NE, Washington, DC 20426.

Instructions: For detailed instructions on submitting comments and additional information on this process, see the Comment Procedures Section of this document.

Docket Nos. RM16-23-000 and AD16-20-000

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SUPPLEMENTARY INFORMATION:

157 FERC ¶ 61,121
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators Docket Nos. RM16-23-000

Electric Storage Participation in Regions with Organized Wholesale Electric Markets AD16-20-000

NOTICE OF PROPOSED RULEMAKING

(November 17, 2016)

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157 FERC ¶ 61,121
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators Docket Nos. RM16-23-000

Electric Storage Participation in Regions with Organized Wholesale Electric Markets AD16-20-000

NOTICE OF PROPOSED RULEMAKING

(November 17, 2016)

I. Introduction

1. In this Notice of Proposed Rulemaking (NOPR), the Federal Energy Regulatory Commission (Commission) is proposing reforms to remove barriers to the participation of electric storage resources¹ and distributed energy resource² aggregations in the

¹ We define an electric storage resource as a resource capable of receiving electric energy from the grid and storing it for later injection of electricity back to the grid regardless of where the resource is located on the electrical system. These resources include all types of electric storage technologies, regardless of their size, storage medium (e.g., batteries, flywheels, compressed air, pumped-hydro, etc.), or whether located on the interstate grid or on a distribution system.

² We define distributed energy resources as a source or sink of power that is located on the distribution system, any subsystem thereof, or behind a customer meter. These resources may include, but are not limited to, electric storage resources, distributed generation, thermal storage, and electric vehicles and their supply equipment.

organized wholesale electric markets.³ We are taking this action pursuant to our legal authority under section 206 of the FPA to ensure that the RTO/ISO tariffs are just and reasonable and not unduly discriminatory or preferential.⁴

2. Resource participation in the organized wholesale electric markets is currently governed by (1) participation models⁵ consisting of market rules designed for different types of resources and (2) the technical requirements for market services that those resources are eligible to provide. Each RTO/ISO establishes the participation models for different types of resources and the technical requirements for providing services in a slightly different way. Sometimes RTO/ISO participation models place limitations on the services that certain types of resources are eligible to provide. For example, Stored Energy Resources are only allowed to provide regulation service in the Midcontinent Independent System Operator, Inc. (MISO). In addition, sometimes the technical requirements for providing a service may limit the types of resources that are able to provide it, such as the requirement for a resource to be running and synchronized to the

³ We define, for present purposes, organized wholesale electric markets as the capacity, energy, and ancillary service markets operated by regional transmission organizations (RTO) and independent system operators (ISO).

⁴ 16 U.S.C. 824e (2012).

⁵ We define a participation model as a set of tariff provisions that accommodate the participation of resources with particular physical and operational characteristics in the organized wholesale electric markets of the RTOs and ISOs.

grid to provide spinning reserves. Many tariffs were originally developed in an era when traditional generation resources were the only resources participating in the organized wholesale electric markets. As new and innovative resources have reached commercial maturity, RTOs/ISOs have updated their tariffs to establish participation models for these resources and, to some degree, reviewed the technical requirements for each service or determined which service the new resource could provide. If an RTO/ISO is not able to update its market rules before a new resource becomes commercially able to sell into the organized wholesale electric markets, the new resource may need to participate under one of the existing participation models developed for some other type of resource. Doing so may limit the market opportunities for new resources and correspondingly limit the potential supply of some services. For instance, some electric storage resources have chosen to participate as demand response resources simply because, absent other participation models, that is the participation model that more closely resembles the manner in which electric storage resources might participate in the organized wholesale electric markets. Further, new resources may have difficulty creating momentum for the market rule changes necessary to facilitate their participation and may thus need to spend considerable time and effort to gain entry to the organized wholesale electric markets.

Where rules designed for traditional generation resources are applied to new technologies, where new technologies are required to fit into existing participation models, and where participation models focus on the eligibility of resources to provide services more so than the technical ability of resources to provide services, barriers can

emerge to the participation of new technologies in the organized wholesale electric markets. We are therefore issuing this NOPR to address these barriers to the participation of electric storage resources and distributed energy resource aggregations in the organized wholesale electric markets.

3. First, we propose to require each RTO/ISO to revise its tariff to establish a participation model consisting of market rules that, recognizing the physical and operational characteristics of electric storage resources, accommodates their participation in the organized wholesale electric markets. As noted above, in this NOPR, we define a participation model as a set of tariff provisions that accommodate the participation of resources with particular physical and operational characteristics in the organized wholesale electric markets of the RTOs and ISOs.⁶ For example, the California Independent System Operator Corporation's (CAISO) tariff defines several participation models, including those for Participating Generators, Proxy Demand Resources, Reliability Demand Response Resources, and Non-Generator Resources. These participation models create unique rules for these different types of resources where they need to be distinguished from other types of market participants. For example, the CAISO Tariff defines Non-Generator Resources as "[r]esources that operate as either Generation or Load and that can be dispatched to any operating level within their entire

⁶ See *supra* note 5.

capacity range but are also constrained by a MWh limit to (1) generate Energy, (2) curtail the consumption of Energy in the case of demand response, or (3) consume Energy.”⁷

Since Non-Generator Resources are operationally unique, CAISO has created rules for them that include, but are not limited to, the requirement to enter into participating generator and participating load agreements to participate in the CAISO markets,⁸ the ability to participate in the Regulation Energy Management program,⁹ the conditions under which payments are rescinded due to MWh constraints,¹⁰ and the relevant bidding parameters.¹¹ Given the unique attributes of electric storage resources, establishing a participation model consisting of market rules that acknowledge their unique attributes will enable them to effectively participate in the organized wholesale electric markets. This participation model could adapt existing market rules to incorporate the reforms proposed below and/or create a new set of rules to accommodate the participation of electric storage resources, depending on the existing market construct in each RTO/ISO.

⁷ CAISO Response at 3 (citing CAISO Tariff, App. A).

⁸ See CAISO Tariff, sections 4.6 and 4.7.

⁹ See CAISO Tariff, section 8.4.1.2. Regulation Energy Management is a market feature for resources located within the CAISO Balancing Authority Area that require Energy from the Real-Time Market to offer their full capacity as Regulation. CAISO Tariff, App. A (Definitions).

¹⁰ See CAISO Tariff, sections 8.10.8.4 and 8.10.8.6.

¹¹ See CAISO Tariff, section 30.5.6.

4. The proposed participation model must (1) ensure that electric storage resources are eligible to provide all capacity, energy and ancillary services that they are technically capable of providing in the organized wholesale electric markets; (2) incorporate bidding parameters¹² that reflect and account for the physical and operational characteristics of electric storage resources; (3) ensure that electric storage resources can be dispatched and can set the wholesale market clearing price as both a wholesale seller and wholesale buyer consistent with existing market rules that govern when a resource can set the wholesale price; (4) establish a minimum size requirement for participation in the organized wholesale electric markets that does not exceed 100 kW; and (5) specify that the sale of energy from the organized wholesale electric markets to an electric storage resource that the resource then resells back to those markets must be at the wholesale locational marginal price (LMP).

5. Second, we propose to require each RTO/ISO to revise its tariff to allow distributed energy resource aggregators,¹³ including electric storage resources, to

¹² We refer to bidding parameters as the physical and operational constraints that a resource would identify per RTO/ISO requirements when submitting offers to sell capacity, energy, or ancillary services or bids to buy energy in the organized wholesale electric markets. Commission Staff referred to these as “bid parameters” in the Data Requests and Request for Comments issued on April 11, 2016 in Docket No. AD16-20-000.

¹³ We define distributed energy resource aggregator as an entity that aggregates one or more distributed energy resources for purposes of participation in the organized wholesale capacity, energy, and ancillary service markets of the RTOs and ISOs.

participate directly in the organized wholesale electric markets. Specifically, we propose to require each RTO/ISO to establish distributed energy resource aggregators as a type of market participant and allow the distributed energy resource aggregators to register distributed energy resource aggregations under the participation model in the RTO/ISO tariff that best accommodates the physical and operational characteristics of the distributed energy resource aggregation. We also propose to require that each RTO/ISO, to accommodate the participation of distributed energy resource aggregations in the organized wholesale electric markets, establish market rules on: (1) eligibility to participate in the organized wholesale electric markets through a distributed energy resource aggregator; (2) locational requirements for distributed energy resource aggregations; (3) distribution factors and bidding parameters for distributed energy resource aggregations; (4) information and data requirements for distributed energy resource aggregations; (5) modifications to the list of resources in a distributed energy resource aggregation; (6) metering and telemetry system requirements for distributed energy resource aggregations; (7) coordination between the RTO/ISO, distributed energy resource aggregator, and the distribution utility; and (8) market participation agreements for distributed energy resource aggregators.

II. Background

A. Electric Storage Resource and Distributed Energy Resource Aggregation Participation in Organized Wholesale Electric Markets

6. The Commission has an ongoing interest in removing barriers to resources that are technically capable of participating in the organized wholesale electric markets and has been monitoring electric storage resource participation in these markets for some time. In 2010, Commission Staff issued a Request for Comments Regarding Rates, Accounting and Financial Reporting for New Electric Storage Technologies related to alternatives for categorizing and compensating storage services and, in particular, ideas on how best to develop rate policies that accommodate the flexibility of storage, consistent with the FPA.¹⁴ Following that request, the Commission issued several rulemakings that have helped alleviate some of the barriers to electric storage resource participation in organized wholesale electric markets.¹⁵ In addition, the Commission has addressed electric storage-related issues on a case-by-case basis.¹⁶

¹⁴ Request for Comments Regarding Rates, Accounting and Financial Reporting for New Electric Storage Technologies, Docket No. AD10-13-000 (June 11, 2010).

¹⁵ See, e.g., *Frequency Regulation Compensation in the Organized Wholesale Power Markets*, Order No. 755, FERC Stats. & Regs. ¶ 31,324 (2011), *reh'g denied*, Order No. 755-A, 138 FERC ¶ 61,123 (2012) (addressing the provision of frequency regulation in organized wholesale electric markets); *Third-Party Provision of Ancillary Services; Accounting and Financial Reporting for New Electric Storage Technologies*, Order No. 784, FERC Stats. & Regs. ¶ 31,349 (2013), *order on clarification*, Order No. 784-A, 146 FERC ¶ 61,114 (2014) (addressing third-party sales of ancillary services in bilateral markets); *Small Generator Interconnection*

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7. As the capabilities of electric storage resources and distributed energy resources continue to improve and their costs continue to decline, the Commission has become concerned that these resources may face barriers that limit them from participating in organized wholesale electric markets. To further examine this issue, the Commission hosted a panel to discuss electric storage resources at the November 19, 2015 Commission meeting. Subsequently, on April 11, 2016, Commission Staff issued data requests to each of the six RTOs/ISOs, seeking information about the rules in the organized wholesale electric markets that affect the participation of electric storage resources (Data Requests).¹⁷ Concurrently, Commission Staff issued a Request for

Agreements and Procedures, Order No. 792, 145 FERC ¶ 61,159 (2013), *clarifying*, Order No. 792-A, 146 FERC ¶ 61,214 (2014) (addressing interconnection for small generators, including electric storage resources).

¹⁶ See, e.g., *California Indep. Sys. Operator Corp.*, 156 FERC ¶ 61,110 (2016); *Nev. Hydro Co., Inc.*, 122 FERC ¶ 61,272 (2008), *reh'g denied*, 133 FERC ¶ 61,155 (2010); *Western Grid Development, LLC*, 130 FERC ¶ 61,056, *reh'g denied*, 133 FERC ¶ 61,029 (2010); *Midwest Indep. Trans. Sys. Operator, Inc.*, 129 FERC ¶ 61,303 (2009); *New York Indep. Sys. Operator, Inc.*, 127 FERC ¶ 61,135 (2009); *California Indep. Sys. Operator Corp.*, 132 FERC ¶ 61,211 (2010); *PJM Interconnection L.L.C.*, 151 FERC ¶ 61,208, *order on reh'g*, 152 FERC ¶ 61,064 (2015), *order on reh'g and compliance*, 155 FERC ¶ 61,157, *order on reh'g and compliance*, 155 FERC ¶ 61,260 (2016); *PJM Interconnection, L.L.C.*, 132 FERC ¶ 61,203 (2010); *Commonwealth Edison Co.*, 129 FERC ¶ 61,185, at P 8 (2009).

¹⁷ Specifically, Commission Staff requested information related to (1) the eligibility of electric storage resources to participate in the capacity, energy, and ancillary service markets in the RTOs/ISOs; (2) the technical qualification and performance requirements for market participants; (3) the bidding parameters for different types of resources; (4) opportunities for distribution-level and aggregated electric storage resources to participate in the organized wholesale electric markets; (5) the treatment of

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Comments, seeking comments on whether barriers exist to the participation of electric storage resources in the organized wholesale electric markets that may potentially lead to unjust and unreasonable wholesale rates (Request for Comments). In addition to the responses from the RTOs/ISOs, Commission Staff received 44 sets of comments from the entities identified in Appendix A.

8. A number of RTOs/ISOs allow participation of distributed energy resources, including electric storage resources, in the organized wholesale electric markets through distributed energy resource aggregations. For example, CAISO's Distributed Energy Resource Provider model allows for the participation of aggregated distributed energy resources in the energy and ancillary service markets.¹⁸ Other RTOs/ISOs, including PJM Interconnection, L.L.C. (PJM), MISO, New York Independent System Operator, Inc.'s (NYISO), and SPP, allow aggregation in limited circumstances, typically linked to the requirement that the demand-side, generation, and electric storage resources are located behind the same point of interconnection or pricing node.¹⁹ ISO New England

electric storage resources when they are receiving electricity for later injection to the grid; and (6) any forthcoming rule changes or other stakeholder initiatives that may affect the participation of electric storage resources in the organized wholesale electric markets.

¹⁸ See *California Indep. Sys. Operator Corp.*, 155 FERC ¶ 61,229 (2016) (conditionally accepting tariff provisions to facilitate participation of aggregations of distribution-connected or distributed energy resources in CAISO's energy and ancillary service markets).

¹⁹ See PJM Response at 20; MISO Response at 16; SPP Response at 7.

Inc. (ISO-NE) also allows limited aggregations of generators, Alternative Technology Regulation Resources, Asset Related Demands, and demand resources subject to certain parameters.²⁰

B. The Need for Reform

9. The Commission must ensure that the rates, terms and conditions of jurisdictional services under the FPA are just and reasonable and not unduly discriminatory or preferential. Our proposal in this proceeding is a continuation of efforts pursuant to our authority under the FPA to ensure that the RTO/ISO tariffs and market rules produce just and reasonable rates, terms and conditions of service.²¹ The Commission has observed that market rules designed for traditional generation resources can create barriers to entry for emerging technologies. The Commission has responded by promulgating rules that recognize the operational characteristics of non-traditional resources such as variable energy resources and demand response.²² For example, in Order No. 719, the Commission required each RTO/ISO to accept bids from demand response resources, on

²⁰ ISO-NE Response at 26.

²¹ See, e.g., *Integration of Variable Energy Resources*, Order No. 764, FERC Stats. & Regs. ¶ 31,331, *order on reh'g*, Order No. 764-A, 141 FERC ¶ 61,232 (2012), *order on reh'g*, Order No. 764-B, 144 FERC ¶ 61,222 (2013); *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, FERC Stats. & Regs. ¶ 31,281 (2008), *order on reh'g*, Order No. 719-A, FERC Stats. & Regs. ¶ 31,292 (2009), *order on reh'g*, Order No. 719-B, 129 FERC ¶ 61,252 (2009).

²² See, e.g., Order No. 764, FERC Stats. & Regs. ¶ 31,331; Order No. 719, FERC Stats. & Regs. ¶ 31,281.

a basis comparable to any other resources, for ancillary services that are acquired in a competitive bidding process, if the demand response resources met certain criteria.²³ In Order No. 764, the Commission took action to remedy operational and other challenges associated with the integration of variable energy resources caused by existing practices as well as the ancillary services used to manage system variability that were developed at a time when virtually all generation on the system could be scheduled with relative precision and when only load exhibited significant degrees of intra-hour variation.²⁴

10. In this proceeding, we propose to require RTOs/ISOs to address barriers to participation of electric storage resources in the organized wholesale electric markets. As noted above, in this NOPR, we define an electric storage resource as a resource capable of receiving electric energy from the grid and storing it for later injection of electricity back to the grid regardless of where the resource is located on the electrical system.²⁵ These resources include all types of electric storage technologies, regardless of their size, storage medium (e.g., batteries, flywheels, compressed air, pumped-hydro, etc.), or whether located on the interstate grid or on a distribution system.²⁶ Electric storage

²³ Order No. 719, FERC Stats. & Regs. ¶ 31,281 at PP 19, 47-48.

²⁴ Order No. 764, FERC Stats. & Regs. ¶ 31,331.

²⁵ *See supra* note 1.

²⁶ *Id.*

resources include a number of different technologies that can serve as a sink for, or source of, electricity. Electric storage resources' ability to charge and discharge electricity provides these resources with significant operational flexibility, and they can be designed to provide a variety of grid services, including bulk energy services (e.g., capacity and energy) and ancillary services (e.g., regulation and reserves).²⁷

11. The RTOs/ISOs have taken different approaches to integrating electric storage resources into their organized wholesale electric markets. While electric storage resources (including batteries, flywheels, and pumped-hydro facilities) are already providing energy and ancillary services in some organized wholesale electric markets, these resources often must use existing participation models designed for traditional generation or load resources that do not recognize electric storage resources' unique physical and operational characteristics. Some organized wholesale electric markets have defined participation models in their tariffs for electric storage resources, but those models limit the services that electric storage resources may provide.²⁸ For example,

²⁷ Sandia National Laboratories, *DOE/EPRI Electricity Storage Handbook in Collaboration with NRECA*, Report No. SAND2015-1002, Chapter 1 (Feb. 2015) (Sandia Report).

²⁸ See, e.g., *Midwest Indep. Trans. Sys. Operator, Inc.*, 129 FERC ¶ 61,303 at PP 40, 64 (Commission "note[d] that the Midwest ISO [SER] proposal is intended to implement a specific technology, the fly-wheel technology developed by Beacon Power"; and SER category was "specifically designed for a specific technology that provides short-term Stored Resources only in the regulating reserve market"); MISO FERC Electric Tariff, section 1.S (Stored Energy Resources); NYISO Services

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these models often allow eligible electric storage resources to participate only in the regulation market. Other organized wholesale electric market rules are designed for electric storage resources with very specific characteristics, such as pumped-hydro facilities or resources with less than a one-hour maximum run time. Smaller electric storage resources are also generally restricted to participating in the organized wholesale electric markets as demand response, which can limit their ability to employ their full operational range, prohibit them from injecting power onto the grid, and preclude them from providing certain services that they are capable of providing such as operating reserves.

12. We take action in this NOPR so that electric storage resources will be able to participate in the organized wholesale electric markets to the extent they are technically capable of doing so based on rules that take into account their unique characteristics and not based on market rules designed for the unique characteristics of other types of resources. Requiring electric storage resources to use participation models designed for a different type of resource may fail to recognize electric storage resources' physical and

Tariff, section 2.12 (defining Limited Energy Storage Resource as a “Generator authorized to offer Regulation Service only and characterized by limited Energy storage, that is, the inability to sustain continuous operation at maximum Energy withdrawal or maximum Energy injection for a minimum period of one hour.”). NYISO limits Limited Energy Storage Resources to providing regulation service only and Demand Side Resources and Generators that can sustain operation for longer than one hour are not eligible to be Limited Energy Storage Resources. NYISO Response at 3-4.

operational characteristics and their capability to provide energy, capacity and ancillary services in the organized wholesale electric markets. Current tariffs that do not recognize the operational characteristics of electric storage resources serve to limit the participation of electric storage resources in the organized wholesale electric markets and result in inefficient use of these resources (i.e., electric storage resources may be dispatched to provide one service when they could, absent market rule limitations, provide another service more economically). As a result, resources, including electric storage resources, do not get dispatched efficiently, thereby impacting the competitiveness of the market outcomes. Limiting the services an electric storage resource is eligible to provide and limiting the efficiency in which it is dispatched to provide services may also inhibit developers' incentives to design their electric storage resources to provide all capacity, energy and ancillary services these resources could otherwise provide. This further reduces competition for providing those services in the organized wholesale electric markets. Effective integration of electric storage resources into the organized wholesale electric markets would enhance competition and, in turn, help to ensure that these markets produce just and reasonable rates.

13. We are also concerned that existing RTO/ISO tariffs impede the participation of distributed energy resources in the organized wholesale electric markets by providing limited opportunities for distributed energy resource aggregations. Distributed energy resources include a variety of constantly evolving technologies (including, but not limited to, electric storage resources, distributed generation, thermal storage, and electric vehicles

and their supply equipment) that are connected to the power grid at distribution-level voltages. While these distributed energy resources can at times effectively supply the capacity, energy, and ancillary services that are exchanged in the organized wholesale electric markets, they can at times be too small to participate in these markets individually. In addition, responses to the Data Requests and Request for Comments demonstrate that current organized wholesale electric market rules often limit the services distributed energy resources are eligible to provide, in many cases only allowing these resources to be used as demand response or load-side resources when they are located behind a customer meter²⁹ or by imposing prohibitively expensive or otherwise burdensome requirements.³⁰

²⁹ See, e.g., MISO Response at 15 (noting that electric storage resources connected to the distribution system can participate in its markets as Load Modifying Resources and Demand Response Resources –Types I or II); PJM Response at 3-6 (stating that, if an electric storage resource is located behind a customer meter, then PJM considers it demand response, which is not studied for deliverability and is not eligible to inject energy into the distribution or PJM transmission system and noting that any injection would subject it to generator interconnection obligations).

³⁰ See Energy Storage Association Comments at 29 (stating that metering and telemetry requirements and interconnection processes can pose prohibitively high transaction costs for the small project sizes that characterize behind-the-meter storage, which creates undue burdens on behind-the-meter storage participation in most RTOs/ISOs and noting that the ability to bid aggregated distributed resources into wholesale markets is not possible in some RTOs/ISOs and is unclear in others (such as NYISO, which does not allow aggregations to meet the 1 MW size for a Limited Energy Storage Resource)). Energy Storage Association also asserts that at present most RTOs/ISOs do not allow behind-the-meter storage to net inject power to provide

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14. As with electric storage resources, we preliminarily find that the barriers to the participation of distributed energy resources through distributed energy resource aggregations in the organized wholesale electric markets may, in some cases, unnecessarily restrict competition, which could lead to unjust and unreasonable rates. Effective wholesale competition encourages entry and exit and promotes innovation, incentivizes the efficient operation of resources, and allocates risk appropriately between consumers and producers. Removing these barriers will enhance the competitiveness, and in turn the efficiency, of organized wholesale electric markets and thereby help to ensure just and reasonable and not unduly discriminatory or preferential rates for wholesale electric services. We also note that participation of electric storage resources in the organized wholesale electric markets allows for more efficient operation of large thermal generators, enhances reliability, provides congestion relief, improves integration of variable energy resources, and reduces the burden on the transmission system.³¹

wholesale generator services. *Id.* See also NextEra Comments at 11 (stating that every RTO/ISO prohibits behind-the-meter resources from having net injections to the grid).

³¹ Among the benefits cited by a recent report by the Lawrence Berkeley National Laboratory are (1) a less costly, cleaner, and more competitive bulk power system and (2) greater reliability through consumer reliance upon distributed energy resources to provide resilience from bulk power and system and distribution service interruptions. Lawrence Berkeley National Laboratory, *Electric Industry Structure and Regulatory Responses in a High Distributed Energy Resources Future*, at 26-28 (Report 1, Nov. 2015), https://emp.lbl.gov/sites/all/files/lbnl-1003823_0.pdf (Berkeley Lab Report). See also DNV-GL, *A Review of Distributed Energy Resources: New York Independent System Operator*, at 18 (Sept. 2014) (DNV-GL Report),

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15. Distributed energy resource aggregations are often limited to participating in organized wholesale electric markets as demand response, which can limit the aggregations' design and operations, as well as the services they may provide. However, advancements in metering, telemetry, and communication technologies support the aggregation of distributed energy resources, allowing these resources to meet the minimum size requirements to participate in the organized wholesale electric markets under participation models other than demand response. Additionally, demand response models often prohibit distributed energy resources from injecting power back onto the grid or increasing consumption if there is an operational requirement for such performance.³² By requiring RTOs/ISOs to allow the participation of distributed energy

http://www.nyiso.com/public/webdocs/media_room/publications_presentations/Other_Reports/Other_Reports/A_Review_of_Distributed_Energy_Resources_September_2014 ("Benefit streams commonly attributed to distributed energy resources include, among others: Avoided expansion of generation, transmission, or distribution facilities, power outage mitigation or critical power support during power outages (resiliency) and power quality improvement (enhanced reliability); U.S. Department of Energy, *The Potential Benefits of Distributed Generation and Rate-related Issues that May Impede Their Expansion: A Study Pursuant to Section 1817 of the Energy Policy Act of 2005* (Feb. 2007), <https://www.ferc.gov/legal/fed-sta/exp-study.pdf>.; IEA, *Re-powering Markets: market design and regulation during the transition to low-carbon power systems*, at 33 (2016) ("active management of renewable resources connected to distribution networks can help reduce or delay distribution network investments").

³² See PJM Response at 5 (stating that, like other types of resources that participate in PJM's markets only by providing load reductions, demand-side electric storage resources are not studied by PJM through the generation interconnection process and are not allowed to inject energy beyond the customer's meter and onto the distribution or transmission system, as applicable).

resource aggregations, aggregators will be able to bundle distributed energy resources to meet RTO/ISO qualification and performance requirements, and the RTOs/ISOs will be able to capitalize on the aggregation's full operational range. The recent proliferation of, and technological advancements in, distributed energy technologies, as well as their decreasing costs, create opportunities for distributed energy resource aggregations to be eligible to provide a variety of services to the organized wholesale electric markets.³³

16. Accordingly, we propose to require the RTOs/ISOs to revise their tariffs to:

(1) establish a participation model consisting of market rules that, recognizing the physical and operational characteristics of electric storage resources, accommodates their participation in the organized wholesale electric markets and (2) define distributed energy resource aggregators as a type of market participant that can participate in the organized

³³ The Berkeley Lab Report notes that technological and procedural innovation and advancements are leading to substantial reduction in the cost of some of these resources, such as through a continued long-term downward trend in the installed cost of solar PV. Berkeley Lab Report at 50, App. A. It adds that there is a wide range of forecasts of the potential for distributed energy resources over the coming decades, some of which suggest that penetrations could be significant. Estimated increases range from a current 11 percent distributed energy resource penetration rate to 19 percent of required capacity (MW) in the Eastern Interconnection under a base case analysis by 2030; and a projection of a 37.5 percent penetration in the Western Interconnection by 2032. *Id.* at 51 (citing Western Electricity Coordinating Council, *SPSC Study High EE/DR/DG* (Sept. 19, 2013), https://www.wecc.biz/_layouts/15/WopiFrame.aspx?sourcedoc=/Reliability/2032_HighEEDSMDG_StudyReport.docx&action=default&DefaultItemOpen=1; Navigant Consulting, Inc., *Assessment of Demand-Side Resources Within the Eastern Interconnection*, March 2013, <http://bit.ly/EISPCdsr>).

wholesale electric markets under the participation model that best accommodates the physical and operational characteristics of its distributed energy resource aggregation. These proposed requirements will clarify how electric storage resources and distributed energy resources of all types and sizes may provide services in the organized wholesale electric markets that they are technically capable of providing.

III. Discussion

A. Elimination of Barriers to Electric Storage Resource Participation in Organized Wholesale Electric Markets

1. Creation of a Participation Model for Electric Storage Resources

i. Introduction

17. Resource participation in organized wholesale electric markets is currently governed by (1) participation models consisting of market rules designed for different types of resources and (2) the technical requirements for market services that those resources are eligible to provide. As noted above, in this NOPR, we define a participation model as a set of tariff provisions that accommodate the participation of resources with particular physical and operational characteristics in the organized wholesale electric markets of the RTOs and ISOs.³⁴ While these participation models are designed to accommodate the unique characteristics of different resources, new technologies may be required to fit into existing participation models when market rules

³⁴ See *supra* note 5.

for their unique characteristics have not been developed. Moreover, even where participation models for new technologies, such as electric storage resources, do exist, they may unnecessarily limit a resource's ability to qualify for the participation model or to provide certain services using it, despite the technical capabilities of the resource.

18. The Commission previously has allowed flexibility for each RTO/ISO to approach the integration of electric storage resources in its organized wholesale electric markets differently. RTOs/ISOs developed most of their participation models before electric storage resources achieved their current technical capability and commercial viability, so some markets rely on these existing models for the participation of electric storage resources. For example, ISO-NE indicates that, for an electric storage resource to be eligible to provide all wholesale services, it must register as a Generator Asset,³⁵ which is a participation model designed for traditional generation and which may not reflect the distinct operational characteristics or capabilities of electric storage resources.

Alternatively, some RTOs/ISOs have created participation models for electric storage resources that limit the participation of those resources to the regulation market or are designed for electric storage resources with very specific characteristics, such as pumped-

³⁵ ISO-NE Response at 3-5.

hydro facilities or resources with less than a one-hour maximum run time.³⁶ However, other RTOs/ISOs have created participation models for electric storage resources to provide a wider variety of services in the organized wholesale electric markets (such as PJM's Energy Storage Resource model³⁷ and CAISO's Non-Generator Resource model³⁸). Establishing a robust participation model for electric storage resources will help remove barriers to the participation of electric storage resources in the organized wholesale electric markets and ensure that electric storage resources can provide the services that they are technically capable of providing.

ii. Current Rules

19. In their responses to the Data Requests, the RTOs/ISOs describe opportunities for electric storage resources to provide various energy and ancillary service market services. For example, in CAISO, electric storage resources are eligible to participate in the energy and ancillary service markets as Participating Generators, Non-Generator Resources, Pumped Storage Hydro Units, or Demand Response Resources, even as part of

³⁶ MISO Response at 2 (stating that MISO's Stored Energy Resource model is limited to regulation service); and NYISO Response at 3-4 (stating that NYISO limits Limited Energy Storage Resources to providing regulation service only).

³⁷ An Energy Storage Resource is defined as a "flywheel or battery storage facility solely used for short term storage and injection of energy at a later time to participate in the PJM energy and/or Ancillary Services markets as a Market Seller." PJM Response at 6 (citing PJM Tariff, Att. K, section 1.3.).

³⁸ See *supra* note 7.

distributed energy resource aggregations.³⁹ Under ISO-NE's market rules, electric storage resources can provide all services when they qualify as a generator, provide all services except 10-minute spinning and 10-minute non-spinning reserves when they qualify as demand response, and provide regulation as an Alternative Technology Regulation Resource.⁴⁰

20. In MISO, electric storage resources are eligible to participate as a Stored Energy Resource (which is only eligible to provide regulation), a Generation Resource, a Use-Limited Resource that is unable to operate continuously on a daily basis, and several types of demand response resources (some of which are limited in the products that they are eligible to provide).⁴¹ NYISO allows electric storage resources to qualify as Energy Limited Resources, Limited Energy Storage Resources (which are eligible to provide regulation service only), or demand response resources.⁴² PJM allows electric storage resources to participate as generation resources or demand-side resources (which are not eligible to provide non-synchronized reserves).⁴³ Finally, SPP allows electric storage

³⁹ CAISO Response at 2-8. *See California Indep. Sys. Operator Corp.*, 155 FERC ¶ 61,229.

⁴⁰ ISO-NE Response at 3-5.

⁴¹ MISO Response at 7-8.

⁴² NYISO Response at 1-6.

⁴³ PJM Response at 4.

resources to qualify as Demand Response Resources, Dispatchable Resources, External Resources, External Dynamic Resources, and Quick-Start Resources, if they can sustain output for 60 minutes.⁴⁴

21. Some RTOs/ISOs concede that their existing participation models may fail to address the characteristics of certain electric storage resources.⁴⁵ CAISO urges the Commission to preserve some flexibility for the RTOs/ISOs to develop market rules and participation models that respond to electric storage developments.⁴⁶

iii. Comments

22. Numerous commenters argue that the lack of a participation model that accommodates the participation of electric storage resources creates barriers to their participation in organized wholesale electric markets. For example, Alevo asserts that the lack of a defined asset class for electric storage resources poses a barrier to their participation, limiting market efficiency and competition and increasing costs.⁴⁷ Advanced Energy Economy claims that the failure to account for the unique attributes,

⁴⁴ SPP Response at 3-4.

⁴⁵ MISO Response at 3; NYISO Response at 17.

⁴⁶ CAISO Response at 1-2.

⁴⁷ Alevo Comments at 4, 7-17 (pointing to its analyses of the benefits that electric storage resource participation could provide to energy, capacity, and ancillary service markets).

characteristics, and benefits of advanced energy technologies prevents projects from obtaining financing.⁴⁸ More specifically, Energy Storage Association asserts that NYISO's Behind-the-Meter Net Generator design still effectively excludes participation of electric storage resources because it does not account for electric storage functionality.⁴⁹

23. Many commenters request that the Commission require the RTOs/ISOs to establish a participation model for electric storage resources that allows them to provide all services.⁵⁰ Alevo argues that such a participation model should not limit duration of discharge or services provided,⁵¹ while NY Battery and Energy Storage Consortium states that it should utilize appropriate bidding parameters and resource modeling for electric storage resources.⁵² California Energy Storage Alliance asks the Commission to direct the RTOs/ISOs to develop a market model specific to behind-the-meter electric storage resources, which would allow them to respond to market signals to provide any wholesale market service (e.g., frequency regulation, demand response, spinning reserve)

⁴⁸ Advanced Energy Economy Comments at 7.

⁴⁹ Energy Storage Association Comments at 29-30.

⁵⁰ *Id.* at 8-9, 24; NY Battery and Energy Storage Consortium Comments at 5; Ormat Comments at 2-3; Electric Vehicle R&D Group Comments at 3.

⁵¹ Alevo Comments at 8.

⁵² NY Battery and Energy Storage Consortium Comments at 5.

without restrictions, with its market participation governed by minimum performance requirements.⁵³ Electric Vehicle R&D Group supports the creation of a separate participation model for electric storage resources that allows for bidirectional power flow.⁵⁴ Duke Energy also encourages modifications to market rules to facilitate electric storage resource deployment, subject to reliability requirements and non-preferential treatment.⁵⁵

Other commenters explain how the existing participation models for demand response resources, under which electric storage resources sometimes participate in the organized wholesale electric markets, do not adequately accommodate electric storage resource participation. Advanced Microgrid Solutions asserts that the compensation methods under demand response resource participation models should not be applied to electric storage resources because, unlike the demand reductions that demand response resources provide, the energy that electric storage resources deliver is purchased in the form of energy consumed during another time such that any net-benefit test is unnecessary.⁵⁶ Energy Storage Association, SolarCity, and California Energy Storage Alliance contend

⁵³ California Energy Storage Alliance Comments at 4-5.

⁵⁴ Electric Vehicle R&D Group Comments at 3.

⁵⁵ Duke Energy Comments at 4.

⁵⁶ Advanced Microgrid Solutions Comments at 5.

that the baselines used to measure demand response resource deliveries present a barrier to electric storage resource participation under demand response participation models and can limit the ability of behind-the-meter electric storage resources to provide their full capability into wholesale markets.⁵⁷ SolarCity further argues that requiring behind-the-meter electric storage resources to participate as demand response creates a barrier for these resources, as they are physically and economically capable of providing electricity beyond the customer's load.⁵⁸ Tesla contends that customer-sited resources (such as electric storage resources) are interactive grid resources that are often relegated to act as less flexible demand response resources when participating in organized wholesale electric markets.⁵⁹ Energy Storage Association argues that wholesale demand response constructs can prohibit behind-the-meter electric storage resources from offering other services.⁶⁰

24. Many commenters also state that behind-the-meter electric storage resources should be permitted to inject power beyond the retail meter. Energy Storage Association and NextEra argue that no RTO/ISO allows behind-the-meter storage to net inject power

⁵⁷ Energy Storage Association Comments at 28; SolarCity Comments at 8; California Energy Storage Alliance Comments at 4.

⁵⁸ SolarCity Comments at 4.

⁵⁹ Tesla Comments at 4.

⁶⁰ Energy Storage Association Comments at 28.

to provide wholesale generator services.⁶¹ Similarly, Advanced Energy Economy and Solar Grid Storage argue that PJM's restriction on the injection of energy past a customer's retail meter during operations for providing ancillary services in their markets is a barrier to storage.⁶² Solar Grid Storage argues that PJM's "no injection" barrier effectively excludes all residential customers with storage from participation in the PJM ancillary service markets, despite the growing potential of this customer segment to provide meaningful resources to that organized market.⁶³

25. Some commenters call for the creation of a "load increase" participation model for electric storage resources that allows electric storage resources to be dispatched to receive electricity from the grid. For example, National Hydropower Association states that pumped-storage projects are not adequately valued because they are regarded as either a generator or a load, which results in the undervaluation of these projects and no new major plants being built in the last 30 years.⁶⁴ National Hydropower Association asks the

⁶¹ *Id.* at 29; NextEra Comments at 11. NextEra explains that a net injection is when the output of an electric storage resource exceeds the customer's load that it is sited with and the electric storage resource exports power back to the grid.

⁶² Advanced Energy Economy Comments at 16-17; Solar Grid Storage Comments at 2.

⁶³ Solar Grid Storage Comments at 3.

⁶⁴ National Hydropower Association Comments at 5-6.

Commission to consider adding pumped-storage as a dispatchable “load increase” demand response resource.⁶⁵

iv. Proposed Reforms

26. As numerous commenters state, existing RTO/ISO rules that govern participation of electric storage resources in some organized wholesale electric markets fail to ensure that electric storage resources that are technically capable of providing specific services are permitted to do so. Providing a participation model that recognizes the unique characteristics of electric storage resources will help eliminate barriers to their participation in the organized wholesale electric markets and promote competition and economic efficiency. We therefore propose to require each RTO/ISO to revise its tariff to include a participation model consisting of market rules that, recognizing the physical and operational characteristics of electric storage resources, accommodates their participation in organized wholesale electric markets.

27. As the costs of electric storage resources continue to decline and their technical potential expands, the ability of these resources to provide operational and economic benefits to the organized wholesale electric markets will increase. We preliminarily find that it is important to remove barriers to participation now so that the competitive benefits are realized without delay.

⁶⁵ *Id.* at 6.

28. We thus preliminarily find that it is necessary to take action to remove barriers to the participation of electric storage resources in organized wholesale electric markets by requiring that the RTOs/ISOs revise their tariffs to establish a participation model consisting of market rules that, recognizing the physical and operational characteristics of electric storage resources, accommodates their participation in the organized wholesale electric markets. In addition, to accommodate the physical and operational characteristics of electric storage resources, we propose to require that this participation model satisfy each of the following requirements (as discussed in detail in Section III.A.2 of this NOPR):

- a. Electric storage resources must be eligible to provide all capacity, energy and ancillary services that they are technically capable of providing in the organized wholesale electric markets;
- b. The bidding parameters incorporated in the participation model must reflect and account for the physical and operational characteristics of electric storage resources;
- c. Electric storage resources can be dispatched and can set the wholesale market clearing price as both a wholesale seller and a wholesale buyer consistent with existing rules that govern when a resource can set the wholesale price;
- d. The minimum size requirement for electric storage resources to participate in the organized wholesale electric markets must not exceed 100 kW; and
- e. The sale of energy from the organized wholesale electric markets to an electric storage resource that the resource then resells back to those markets must be at the wholesale LMP.

29. To further ensure that the proposed participation model for electric storage resources will accommodate both existing and future electric storage resource technologies, we propose that each RTO/ISO define the criteria in its tariff that a resource

must meet to qualify to use this participation model based on the physical and operational attributes of electric storage resources, namely their ability to both charge and discharge energy. As such, the qualification criteria for the proposed participation model must not limit participation to any particular type of electric storage resource or other technology. In addition, those qualification criteria should ensure that the RTO/ISO is able to dispatch the resource in a way that recognizes its physical constraints and optimizes its benefits to the RTO/ISO. We do not at this time propose to define the qualification criteria that each RTO/ISO use but rather propose to provide the RTOs/ISOs with flexibility to propose qualification criteria that best suit their proposed participation models. However, we invite comment on whether the Commission should establish the qualification criteria and, if so, what specific qualification criteria the Commission should require.

30. We are not proposing to limit the use of this participation model exclusively to electric storage resources as defined herein. While the requirements for the proposed participation model set forth here are designed to accommodate the physical and operational characteristics of electric storage resources, we acknowledge that there may be other types of resources whose physical or operational characteristics could qualify

under the proposed participation model. This may be particularly true for the distributed energy resource aggregations considered in Section III.B below.⁶⁶

31. In addition to including a participation model for electric storage resources in its tariff, we propose that each RTO/ISO propose any necessary additions or modifications to its existing tariff provisions to specify: (1) whether resources that qualify to use the participation model for electric storage resources will participate in the organized wholesale electric markets through existing or new market participation agreements; and (2) whether particular existing market rules apply to resources participating under the electric storage resource participation model. CAISO, for example, has adopted numerous tariff revisions for its Non-Generator Resource participation model.⁶⁷

⁶⁶ For example, resources such as thermal storage that can both increase and decrease their energy consumption could aggregate with other distributed energy resources with common physical or operational characteristics and qualify as a market participant using the participation model proposed here.

⁶⁷ See, e.g., CAISO Tariff, sections 4.6 (Relationship Between CAISO and supply resources), 4.7 (Relationship between CAISO and participating loads), 8.4.1.2 (availability of Regulation Energy Management to Scheduling Coordinators for Non-Generator Resources), 8.10.8.4 (Rescission of Ancillary Service Capacity Payments for Non-Generator Resources), 8.10.8.6 (Rescission of Payments for Regulation Up and Regulation Down Capacity), 11.8 (Bid cost recovery for scheduling coordinators for Non-Generator Resources), 27.9 (MWh Constraints for Non-Generator Resources), 30.5.6 (bid components of Non-Generator Resource bids), 31.2 (Day-ahead market power mitigation process), 34.1.5 (Mitigating of Bids in the real time market), 40.10.3.2 Flexible Capacity Category-- Base Ramping Resources (addressing inclusion of Non-Generator Resources), 40.10.3.3 Flexible Capacity Category -- Peak Ramping Resources (addressing inclusion of Non-Generator Resources), 40.10.3.4 Flexible

(continued...)

32. Finally, we recognize that there are implementation costs for creating a new participation model for electric storage resources. While we believe the participation model and its characteristics described below will benefit the participation of electric storage resources in the organized wholesale electric markets, we acknowledge that the RTOs/ISOs will need to develop rules that govern the participation model as well as make software changes to reflect how these resources will be modeled and dispatched when they participate in the markets. We therefore seek comment from the RTOs/ISOs on the changes that would be required to implement the proposed participation model for electric storage resources as well as the associated costs and how those costs could be minimized.

2. **Requirements for the Participation Model for Electric Storage Resources**

a. **Eligibility to Participate in Organized Wholesale Electric Markets**

i. **Introduction**

33. Electric storage resources have the potential to provide a diverse array of services to the organized wholesale electric markets and to be designed to meet various technical requirements. However, in many cases, the existing participation models that electric storage resources are eligible to use in the RTOs/ISOs preclude electric storage resources

Capacity Category -- Super-Peak Ramping Resources (addressing inclusion of Non-Generator Resources), 40.10.6.1 (Day-Ahead and Real-Time Availability providing for certain Non-Generator Resources bidding requirements).

from providing all of the services that they are technically capable of providing. In other instances, barriers may emerge as a result of the existing technical requirements for providing certain services that may not be appropriate for fast and controllable technologies such as electric storage resources. Market rules that were designed for traditional generation technologies or that otherwise prevent new technologies from providing services that they are technically capable of providing can have detrimental impacts on the competitiveness of the organized wholesale electric markets.

ii. Current Rules

34. Several of the RTOs/ISOs identify limitations on the services that electric storage resources may provide, depending on the participation model an electric storage resource elects to use. ISO-NE states that the non-dispatchability of Settlement Only Resources and non-dispatchable generators prohibits such resources from providing operating reserves. In addition, resources that cannot provide energy within 10 minutes cannot provide 10-minute spinning or 10-minute non-spinning reserves.⁶⁸ ISO-NE also states that demand response resources with one or more controllable generators, including storage resources, are not eligible to provide 10-minute spinning reserve. In ISO-NE,

⁶⁸ ISO-NE Response at 11.

electric storage resources can only provide regulation as an Alternative Technology Regulation Resource.⁶⁹

35. MISO states that a Stored Energy Resource is not qualified for capacity, energy, ramp capability and contingency reserves.⁷⁰ MISO states that Demand Response Resource – Type I is not eligible for regulating reserve and ramp capability products and that Dispatchable Intermittent Resources are a subset of Generation Resources that are not eligible to provide regulating reserves and contingency reserves. MISO states that the Load Modifying Resource category is designed to provide energy in emergency conditions and is only intended for the provision of capacity. MISO also states that Emergency Demand Response can only provide emergency energy, on a voluntary basis.

36. NYISO states that Limited Energy Storage Resources are limited to selling only regulation service in the ancillary service market.⁷¹ NYISO further states that Emergency Demand Response Program resources are only eligible to provide energy, Special Case Resources are only eligible to provide energy and capacity, and Demand Side Ancillary Services Program Resources are only eligible to provide ancillary services. PJM states that demand response resources, including electric storage resources, are ineligible to

⁶⁹ *Id.* at 3-5.

⁷⁰ MISO Response at 7-8.

⁷¹ NYISO Response at 6-7.

provide non-synchronized reserves because demand response resources are already synchronized to the grid when consuming power, and so would always be classified as sync reserves when curtailing.⁷²

iii. Comments

37. Many commenters point to organized wholesale electric markets where electric storage resources cannot participate, or cannot participate fully, because market rules are either designed for traditional generation or they place unnecessary limitations on electric storage resources. Both Advanced Energy Economy and NextEra argue that a resource's eligibility to provide a particular service should be based on whether it has the technical attributes necessary to provide that service rather than on its participation model.⁷³ EEI argues that RTOs/ISOs may need to modify their tariffs to account for electric storage resources because many existing market rules went into place prior to the relatively recent advances in electric storage technology.⁷⁴ Likewise, Alevo contends that applying market rules to electric storage resources that were designed for transmission, generation, and demand assets unfairly disadvantages electric storage resources.⁷⁵ SolarCity claims

⁷² PJM Response at 4.

⁷³ Advanced Energy Economy Comments at 10-11; NextEra Comments at 5.

⁷⁴ EEI Comments at 4.

⁷⁵ Alevo Comments at 8.

that market rules that prevent the participation of electric storage resources in multiple markets, particularly for ancillary services, discriminate against behind-the-meter electric storage resources that can provide multiple services concurrently by preventing them from stacking multiple value streams.⁷⁶ SolarCity suggests that the provision of one wholesale market product should not preclude provision of other wholesale market products when resources are technically capable of providing multiple services.

38. Some commenters note concerns with the eligibility of electric storage resources to provide services in specific markets. According to AES Companies, Indianapolis Power & Light Company's Harding Street Battery Energy Storage System, a fully-developed grid-scale battery, cannot participate in MISO's markets because of the limitations placed on the services Stored Energy Resources are eligible to provide and the way they are dispatched.⁷⁷ AES Companies further note that MISO's Stored Energy Resource definition specifically disallows capacity accreditation, even though some electric storage resources have sufficient discharge duration to provide capacity and ancillary services.⁷⁸ Similarly, Minnesota Energy Storage Alliance contends that none of the participation models that allow electric storage resources to participate in MISO's

⁷⁶ SolarCity Comments at 5.

⁷⁷ AES Companies Comments at 9-10 (citing MISO Response at 3).

⁷⁸ *Id.* at 2, 14.

capacity, energy, and ancillary service markets facilitate participation of battery storage technologies and, in some cases, they limit the products an electric storage resource can provide.⁷⁹ In contrast, Manitoba Hydro, which operates hydroelectric facilities with reservoir storage that participate in the MISO market as Use-Limited Resources, states that MISO's current market rules are not barriers to electric storage resource participation.⁸⁰

39. NY Battery and Energy Storage Consortium asserts that NYISO's market rules prevent electric storage resources from fully participating in NYISO's markets, noting that electric storage resources with less than 60 minutes of output duration can only participate as Limited Energy Storage Resources and can only provide regulation.⁸¹ NY Transmission Owners also argue that NYISO's rules do not reflect the ability of certain electric storage resources to provide their maximum output for regulation service over a

⁷⁹ Minnesota Energy Storage Alliance Comments at 2, 4. For example, Minnesota Energy Storage Alliance contends that MISO's Demand Response Resource - Type I classification is inappropriate for advanced electric storage resources because it is designed for resources that respond as a single block, on or off, and cannot provide regulating reserve and ramping products.

⁸⁰ Manitoba Hydro Comments at 4.

⁸¹ NY Battery and Energy Storage Consortium Comments at 5.

multi-hour period and do not allow them to participate in the energy and ancillary service markets.⁸²

40. According to Energy Storage Association, resources that participate under CAISO's Proxy Demand Response participation model are prohibited from providing frequency regulation, even though they may be technically capable of doing so.⁸³

Finally, NextEra notes that ISO-NE, NYISO, and MISO prohibit an electric storage resource offering regulation from offering any other service, even though a longer-duration electric storage resource could provide regulation from a portion of its capacity while providing other reserve services or energy from the remainder of its capacity.⁸⁴

41. Other commenters focus on technical requirements that limit the ability of electric storage resource to provide certain services. NRECA states that minimum technical requirements should not create undue barriers to resources capable of performing a service.⁸⁵ Similarly, APPA states that RTOs/ISOs should establish reasonable

⁸² NY Transmission Owners Comments at 3.

⁸³ Energy Storage Association Comments at 28.

⁸⁴ NextEra Comments at 5 (citing MISO Response at 7; ISO NE Response at 3; NYISO Response at 7).

⁸⁵ NRECA Comments at 6-7.

qualification criteria on a resource-specific basis.⁸⁶ NY Battery and Energy Storage Consortium argues that distributed electric storage resources, both grid-connected and customer-sited, face barriers to market participation due to eligibility rules and qualification/performance requirements that should be eliminated.⁸⁷

42. Some commenters focus on the technical requirements in the regulation markets. Viridity explains that, while the rapid ramp rates of electric storage resources allow them to provide regulation service, their discharge is of limited duration, so RTOs/ISOs should utilize these resources for short periods.⁸⁸ According to Viridity, requiring such resources to provide regulation service over longer periods is inconsistent with the nature of frequency response and is detrimental to the life span and effectiveness of these resources. NextEra contends that, despite implementation of Order No. 755 (which removed certain barriers to the ability of fast-acting resources to provide frequency regulation service), MISO and SPP continue to rely on the slow ramping automatic generation control signal developed for traditional generation resources for regulation

⁸⁶ APPA Comments at 10-11.

⁸⁷ NY Battery and Energy Storage Consortium Comments at 6.

⁸⁸ Viridity Comments at 3-4.

service.⁸⁹ NextEra notes that advanced electric storage technologies can respond faster than these slower regulation signals allow. NextEra points out that, in contrast, NYISO matches the dispatch of regulation resources to the specific ramping capabilities of each resource.⁹⁰

43. Other commenters contend that reliability standards may preclude electric storage resources from providing certain ancillary services. Specifically, Energy Storage Association states that NYISO suggested that the Northeast Power Coordinating Council's (NPCC) qualification criteria may prohibit grid-connected electric storage resources from providing synchronized reserves because inverter-based resources like electric storage cannot comply with the required settings inherent to synchronous generators.⁹¹ Similarly, ISO-NE states that demand response resources are precluded from providing 10-minute spinning reserve per the ISO-NE tariff definition, which is

⁸⁹ NextEra Comments at 9 (citing <https://www.misoenergy.org/Library/Repository/Communication%20Material/Market%20Enhancements/Market%20Roadmap/Market%20Roadmap%20Priorities.pdf>) (noting that MISO is pursuing an automatic generation control enhancement that would implement a faster signal similar to those used by other RTOs/ISOs).

⁹⁰ *Id.* at 9.

⁹¹ Energy Storage Association Comments at 14, 27.

based on the NPCC requirement that loads cannot provide synchronized reserve if the reduction in load is dependent on starting a generator.⁹²

44. National Electrical Manufacturers Association argues that, in ancillary service markets, spinning reserves are limited to online, synchronized spinning generation resources. According to National Electrical Manufacturers Association, electric storage systems capable of providing fast-reacting, synchronized electricity should be allowed to compete fully to provide spinning reserves.⁹³ Wellhead asks the Commission to require changes to NERC definitions so that non-synchronous resources are not categorically excluded from providing reserves. Wellhead notes that, under the NERC definition of “Spinning Reserves,” the phrase “unloaded generation that is synchronized” does not clearly allow electric storage resources to participate as spinning reserves. Wellhead also notes that NERC’s definition of “Operating Reserves – Spinning” also does not clearly allow for market participation of electric storage resources because they are not generation synchronized to the system.⁹⁴

45. Commenters also note that the requirement in some RTOs and ISOs to have an energy schedule to provide ancillary services is a barrier to electric storage resource

⁹² ISO-NE Response at 11.

⁹³ National Electrical Manufacturers Association Comments at 3.

⁹⁴ Wellhead Comments at 3-4.

participation in ancillary service markets. Commenting on MISO's market rules, Energy Storage Association argues that electric storage resources should not have to offer energy to participate in certain ancillary service markets because, unlike traditional generators, electric storage resources are able to ramp immediately to provide spinning reserve and ramping service without having to provide energy to do so.⁹⁵ Energy Storage Association explains that requiring an electric storage resource to offer energy greatly diminishes its capability to provide services in the ancillary service markets because storage resources are energy-limited.

46. For the capacity markets, commenters ask the Commission to clarify that an electric storage resource should be allowed to de-rate its capacity (i.e., offer a quantity less than its nameplate capacity) to ensure it can satisfy the minimum run-time requirement.⁹⁶ Energy Storage Association states, for example, that, in the NYISO and MISO capacity markets, an electric storage resource with a run-time duration of less than four hours relative to its nameplate capacity should be able to qualify for capacity at a lower power level than it would be able to sustain for four hours at nameplate output.

⁹⁵ Energy Storage Association Comments at 13-14 (citing MISO Response at 11, n.9 (referring to Business Practice Manual sections that describe requirements for these products, which state "Committed Generation Resources" are eligible to provide these products), 14, 27).

⁹⁶ *Id.* at 22-23; NY Battery and Energy Storage Consortium Comments at 6; RES Americas Comments at 4.

More specifically, NY Battery and Energy Storage Consortium states that a 10 MW/2-hour storage resource should be able to qualify for 5 MW of capacity as long as it can sustain 5 MW for 4 hours.

47. In contrast, some commenters, such as APPA, state that eligibility is not a significant problem for electric storage resources.⁹⁷ Similarly, Electric Power Supply Association argues that the RTO/ISO responses to the Data Requests show that electric storage resources can fully participate in the organized wholesale electric markets.⁹⁸ The PJM Market Monitor also claims there are no market rules that artificially preclude participation by electric storage resources in any of PJM's markets.⁹⁹ The PJM Market Monitor states that electric storage resources can make offers directly into PJM's wholesale markets to provide energy, capacity, and ancillary services or can participate as demand response resources.

iv. Proposed Reforms

48. We propose to require RTOs/ISOs to modify their tariffs to establish a participation model consisting of market rules for electric storage resources under which a participating resource is eligible to provide any capacity, energy, and ancillary service

⁹⁷ APPA Comments at 10.

⁹⁸ Electric Power Supply Association Comments at 9.

⁹⁹ PJM Market Monitor Comments at 4.

that it is technically capable of providing in the organized wholesale electric markets. In addition, we propose that electric storage resources should be able, as part of the participation model, to be eligible to provide services that the RTOs/ISOs do not procure through a market mechanism, such as blackstart, primary frequency response, and reactive power, if they are technically capable. Where compensation for these services exists, electric storage resources should also receive such compensation commensurate with the service provided.

49. We also propose to require each RTO/ISO to revise its tariff to clarify that an electric storage resource may de-rate its capacity to meet minimum run-time requirements to provide capacity or other services. This proposed requirement will help ensure that electric storage resources are able to provide all services that they are technically capable of providing by accommodating their physical and operational characteristics, while still maintaining the quality and reliability of services they seek to provide. In RTOs/ISOs with capacity markets, we propose that the de-rated capacity value for electric storage resources be consistent with the quantity of energy that must be offered into the day-ahead energy market for resources with capacity obligations. We preliminarily find that this reform will remove a barrier to the participation of electric storage resources in the organized wholesale electric markets related to minimum run-time requirements and help ensure that the resources that do de-rate their capacity will be able to meet their capacity supply obligations if called upon.

50. We preliminarily conclude that a market participant's eligibility to provide a particular reserve service should not be conditioned on requirements that were designed for synchronous generators, specifically the requirement to be online and synchronized to the grid to be eligible to provide ancillary services. Newer technologies, particularly electric storage resources, tend to be capable of faster start-up times and higher ramp rates than traditional synchronous generators and are therefore able to provide ramping, spinning, and regulating reserve services without already being online and running. Therefore, we preliminarily find that participation in ancillary service markets should be based on a resource's ability to provide services when it is called upon rather than on the real-time operating status of the resource.

51. However, we acknowledge that all of the RTOs/ISOs co-optimize energy and ancillary services dispatch and pricing and therefore may condition eligibility to provide ancillary services on having an energy schedule. As a result, it is not clear whether eliminating the requirement for a resource to be online and synchronized to the grid would be impactful given the continued need to have an energy schedule. Therefore we seek comment on whether the requirement to have an energy schedule to provide ancillary services could be adjusted so that electric storage resources and other technically-capable resources could participate in the ancillary service markets independent of offering energy to the RTO/ISO. Specifically, we seek comment on whether dispatch and pricing of energy and ancillary services would continue to be internally consistent if a resource were not required to offer to provide energy in order to

offer to provide ancillary services. Further, we seek comment on whether the capability of resources to provide an ancillary service absent an energy schedule can be determined in the regular performance tests that the RTO/ISO conducts and whether a resource's start-up time and ramp capability are generally represented in bidding parameters and would adequately guarantee the resource's ability to provide other services absent energy market participation. Additionally, we seek comment on the extent of software changes necessary to factor the elimination of such an energy schedule requirement into the RTO/ISO co-optimization models.

52. Several commenters also identified concerns with how definitions in the Glossary of Terms used in NERC reliability standards could potentially limit participation of electric storage resources and other non-synchronous resources in the reserve markets. While it appears that some of the Glossary of Terms definitions were created for synchronous generation, it is unclear the extent to which these definitions could potentially limit participation of non-synchronous resources in the organized wholesale electric markets. Therefore, we seek comment on whether and to what extent the Commission-approved NERC Glossary of Terms and associated Reliability Standards or regional reliability requirements may create barriers to the participation of electric storage resources or other non-synchronous technologies in the organized wholesale electric markets.

b. Bidding Parameters for Electric Storage Resources**i. Introduction**

53. Bidding parameters allow resources participating in the organized wholesale markets to identify their physical and operational characteristics so that the RTO/ISO can model and dispatch the resource consistent with its operational constraints. Due to an electric storage resource's ability to both receive and provide electricity at varying speeds and duration and to transition between operating modes, it may be more efficient for the RTOs/ISOs to model, optimize, and dispatch electric storage resources differently than they do traditional generation. By requiring electric storage resources to use bidding parameters developed for traditional generators or other supply resources, RTOs/ISOs may fail to effectively utilize these resources, possibly precluding electric storage resources from providing all of the services that they are physically and technically capable of providing in a way that optimizes their operational capabilities and maximizes the benefits they provide. This barrier to electric storage resource participation in organized wholesale electric markets could lead to over-procurement of less efficient resources and increased cost to load.

ii. Current Rules

54. Under current market rules, resource bidding parameters vary greatly between the RTOs/ISOs. Some RTOs/ISOs require the same bidding parameters from all resources offering into a specific market, regardless of the participation model under which these resources participate, while others tie bidding parameters to specific participation models.

For example, ISO-NE requires the same bidding parameters from all resources, including electric storage resources, participating in its capacity, forward reserve, and regulation markets.¹⁰⁰ In ISO-NE's energy market, bidding parameters reflect the physical characteristics of each participation model such as maximum daily starts, maximum consumption for dispatch asset related demand, and minimum time between reduction for demand response resources. Similarly, SPP requires all resources participating in its day-ahead and real-time markets under any participation model to provide a specific set of bidding parameters to validate their offers.¹⁰¹

55. CAISO's market rules also require a defined list of parameters for all bids. In addition, however, CAISO requires supplemental parameters depending on the participation model under which a resource is participating in its market (i.e., Participating Generator, Participating Load, or Non-Generator Resource).¹⁰² Specifically, CAISO explains that bids for participating loads, which include pumping load or Pumped-Storage Hydro Units, may include pumping level (in megawatts (MW)), minimum load bid (generation mode of a pumped-storage hydro unit), load distribution

¹⁰⁰ ISO-NE Response at 24-25.

¹⁰¹ SPP Response at 5-6.

¹⁰² CAISO Response at 13-14 (citing CAISO Tariff, section 30).

factor, ramp rate, energy limit, pumping cost, and pump shut-down costs.¹⁰³ CAISO notes that, unlike under the generator resource model, these resources must submit lower and upper charge limits. Moreover, the Commission recently accepted revisions to CAISO's tariff to allow scheduling coordinators representing non-generator resources to include state-of-charge as a bidding parameter.¹⁰⁴

56. Electric storage resources participating in NYISO's markets must generally submit the same bidding parameters as other resources, with some exceptions.¹⁰⁵ Limited Energy Storage Resources providing regulation service exchange a "state of charge management" signal with the NYISO to facilitate the efficient use of their capabilities. NYISO does not require Limited Energy Storage Resources, unlike other generators, to provide regulation capacity response rates, normal response rates, or emergency response rates with their regulation service bids. In addition, in NYISO, electric storage resources acting as a component of a Demand Side Ancillary Services Program resource may only submit one normal response rate equaling the electric storage resource's emergency response rate, while traditional generators may submit up to three normal response rates.

¹⁰³ *Id.* at 13-14 (citing CAISO Tariff, section 30.5.2.3).

¹⁰⁴ *California Indep. Sys. Operator Corp.*, 156 FERC ¶ 61,110.

¹⁰⁵ NYISO Response at 12 (citing NYISO's Market Participant User's Guide (Dec. 2015)).

57. In MISO, bidding parameters vary between markets and participation models. MISO's market rules allow common bidding parameters for each participation model, with a few exceptions.¹⁰⁶ For example, since MISO manages the state of charge for Stored Energy Resources, it requires the following additional bidding parameters for these resources: hourly maximum energy storage level; hourly maximum energy charge rate; hourly maximum energy discharge rate; hourly energy storage loss rate; and hourly full charge energy withdrawal rate.

58. Bidding parameters in PJM also vary between markets and participation models.¹⁰⁷ Additionally, pumped storage resources offering into the PJM energy markets may either self-schedule or have PJM dispatch their unit pursuant to the pumped storage optimization tool. In either case, the resource must submit the following parameters: initial storage; final storage; maximum storage; minimum storage; pumping efficiency factor; and min/max generating and pumping limits.¹⁰⁸

¹⁰⁶ MISO Response at 14-15 (citing MISO FERC Electric Tariff, section 4.2.6 (Stored Energy Resource Offer)).

¹⁰⁷ PJM Response at 18 (citing PJM Operating Agreement, Schedule 1, section 6.6(f)).

¹⁰⁸ *Id.* (citing PJM Manual 11, Attachment B).

iii. Comments

59. Some commenters focus on the current bidding parameters for electric storage resources. NRECA states that the Commission should not mandate bidding parameters for specific electric storage resources.¹⁰⁹ APPA states that, at this early stage of electric storage resource development, the required bidding parameters should not be so prescriptive as to determine the technologies allowed to deploy, which may constrain the ability of load-serving entities to adopt the least-cost solution.¹¹⁰

60. In contrast, NextEra suggests that each RTO/ISO evaluate how bidding parameters could allow electric storage resources to participate fully in the energy, ancillary service, and capacity markets.¹¹¹ NextEra states that the specific bidding parameters developed for pumped hydro are inadequate for batteries and other advanced electric storage technologies. California Energy Storage Alliance also urges evaluation of existing market bidding parameters to identify revisions focused on the unique characteristics of electric storage resources and their ability to act as both generation and load.¹¹² Energy Storage Association and NY Battery and Energy Storage Consortium agree,

¹⁰⁹ NRECA Comments at 7.

¹¹⁰ APPA Comments at 11.

¹¹¹ NextEra Comments at 10-11.

¹¹² California Energy Storage Alliance Comments at 1-2.

recommending that RTOs/ISOs establish a participation model that incorporates appropriate bidding parameters and resource modeling for electric storage resources.¹¹³

61. Some commenters address the physical and operational characteristics of electric storage resources that create a need for bidding parameters in a participation model for electric storage resources that may differ from those required under participation models for more traditional resources. For example, Alevo argues that electric storage resources are not certain that they can participate in RTO/ISO markets given modeling and bidding parameter limitations in the current RTO/ISO market clearing and dispatch engines.¹¹⁴ Alevo and Energy Storage Association state that the RTOs'/ISOs' market modeling, which Alevo argues is based on traditional resource types that only withdraw electricity from or inject electricity to the grid, does not accommodate electric storage resources' charge and discharge cycles.¹¹⁵ Alevo further contends that no current bidding parameters offer charge and discharge signals that would allow electric storage resources to provide peaking services.¹¹⁶ Similarly, RES Americas contends that accounting for

¹¹³ Energy Storage Association Comments at 8-12; NY Battery and Energy Storage Consortium Comments at 5.

¹¹⁴ Alevo Comments at 20.

¹¹⁵ *Id.*; Energy Storage Association Comments at 9.

¹¹⁶ Alevo Comments at 20.

injections and withdrawals of energy to and from the grid in bidding parameters would improve optimization and dispatch across all asset classes.¹¹⁷

62. A few commenters address bidding parameters in specific organized wholesale electric markets. Energy Storage Association states that MISO's Stored Energy Resource, ISO-NE's Alternative Technology Regulation Resource, and NYISO's Limited Energy Storage Resource participation models explicitly allow electric storage resource participation.¹¹⁸ According to Energy Storage Association, these participation models offer the bidding parameters and modeling mechanisms (such as energy-neutral signal or state-of-charge management) necessary for electric storage resource participation. Minnesota Energy Storage Alliance and AES Companies, however, believe that MISO's current dispatch algorithms do not effectively use electric storage resources because they were designed for flywheels, while advanced battery systems have the ability to continuously charge and discharge.¹¹⁹

63. Other commenters discuss bidding parameters that relate to specific services in the organized wholesale electric markets. National Hydropower Association states that

¹¹⁷ RES Americas Comments at 4.

¹¹⁸ Energy Storage Association Comments at 9-10.

¹¹⁹ Minnesota Energy Storage Alliance Comments at 4; AES Companies Comments at 21.

bidding parameters should reflect electric storage resources' ability to respond to transients with automatic voltage regulation, power system stability, and generator droop.¹²⁰ National Hydropower Association claims that the NERC standards often require these services, but RTOs/ISOs do not include them in any bid evaluation parameters.

64. Some commenters focus on state of charge as a bidding parameter for electric storage resources. Alevo, NextEra, SolarCity, and Energy Storage Association agree that bidding parameters need to reflect an electric storage resource's state of charge.¹²¹ Alevo states that the inability of the RTOs'/ISOs' dispatch and clearing engines to manage hourly and sub-hourly dispatch and consider electric storage resources' states of charge is a barrier to electric storage resource participation.¹²² Alevo and Energy Storage Association recommend including a state of charge bidding parameter in market engine optimization and dispatch modeling because an electric storage resource's energy level at any given moment affects the services it is capable of providing in the subsequent interval.¹²³ NextEra asserts that, although some RTOs/ISOs manage batteries' state of

¹²⁰ National Hydropower Association Comments at 4.

¹²¹ Alevo Comments at 20; NextEra Comments at 10; SolarCity Comments at 9; Energy Storage Association Comments at 11.

¹²² Alevo Comments at 20.

¹²³ *Id.*; Energy Storage Association Comments at 11.

charge when providing regulation service, it is unclear how electric storage resources (or the RTOs/ISOs) can reflect their state of charge in the unit commitment and dispatch algorithms when providing other services.¹²⁴

65. Some commenters focus on the ability of electric storage resources to manage their own state of charge. SolarCity states that RTOs/ISOs should allow electric storage resources to manage their state of charge rather than relying on RTO/ISO accounting estimates of their state of charge, which could lead to faulty dispatch instructions.¹²⁵

Likewise, NextEra recommends that the RTOs/ISOs should allow electric storage resources to choose between RTO/ISO-management and self-management of state of charge.¹²⁶ Energy Storage Association asks that RTOs/ISOs clarify how they would model, optimize, dispatch, and settle electric storage resources using negative generation and state of charge parameters so that electric storage resources understand how they will bid into the market, receive dispatch signals, respond to those signals, and be compensated.¹²⁷ AES Companies state that electric storage resources should be permitted

¹²⁴ NextEra Comments at 10-11. NextEra points to CAISO's proposal to allow energy storage resources to submit their state of charge as a bid parameter in the day-ahead market. This proposal was accepted by the Commission. *See California Indep. Sys. Operator Corp.*, 156 FERC ¶ 61,110 at P 10.

¹²⁵ SolarCity Comments at 9.

¹²⁶ NextEra Comments at 10-11. *See also* Ormat Comments at 3.

¹²⁷ Energy Storage Association Comments at 7.

to optimize their own state of charge because MISO's operating software ignores the benefits of constant charge and availability.¹²⁸

iv. Proposed Reforms

66. We propose to require each RTO/ISO to revise its tariff to include a participation model for electric storage resources that incorporates bidding parameters that reflect and account for the physical and operational characteristics of electric storage resources. The lack of a state-of-charge bidding parameter and the lack of ability for electric storage resources to identify their maximum energy charge rate and maximum energy discharge rate could result in electric storage resources being dispatched in a manner that limits their operational effectiveness. While some existing bidding parameters were developed for older electric storage technologies (such as pumped-hydro facilities), newer storage technologies (such as battery storage) have greater flexibility to transition between charging and discharging. Therefore, bidding parameters designed for slower storage technologies or other types of generation resources that are not capable of charging and discharging energy may limit the opportunity for faster electric storage resources to participate in the organized wholesale electric markets. Appropriate bidding parameters will allow electric storage resources to provide all services they are technically capable of providing and allow the RTOs/ISOs to procure these services more efficiently.

¹²⁸ AES Companies Comments at 21.

67. Specifically, we propose that the RTOs/ISOs establish state of charge, upper charge limit, lower charge limit, maximum energy charge rate, and maximum energy discharge rate as bidding parameters for the participation model for electric storage resources that participating resources must submit, as applicable. The state of charge will allow resources using the participation model for electric storage resources to identify their forecasted state of charge at the end of a market interval,¹²⁹ as defined by the RTO/ISO, while the upper and lower charge limits will prevent the operator from trying to give or take too much energy from the resource. We expect that the state of charge would be telemetered in real time when the RTO/ISO is managing the state of charge, as discussed further below, so that the upper and lower charge limits are not exceeded, but do not propose any specific telemetry requirements. The maximum energy charge rate and maximum energy discharge rate will be used to indicate how quickly the resource can receive electricity from or inject it back to the grid. We preliminarily find that these are the minimum bidding parameters necessary for RTOs/ISOs to effectively dispatch electric storage resources because they provide the RTOs/ISOs with the information about the physical and operational characteristics of electric storage resources that allow these resources to provide the services that they are technically capable of providing.

¹²⁹ See, e.g., CAISO Tariff, Att. A, section 30.5.6 (stating that scheduling coordinators representing Non-Generator Resources may submit bids including the state of charge for the day-ahead market to indicate the forecasted starting physical position of the Non-Generator Resource.).

68. We also propose to require that the participation models for electric storage resources include the following bidding parameters that market participants may submit, at their discretion, for their resource based on its physical constraints or desired operation: minimum charge time, maximum charge time, minimum run time, and maximum run time.¹³⁰ We preliminarily conclude that these optional bidding parameters are necessary to reflect the wide range of physical and operational characteristics of existing and future electric storage technologies. Specifically, electric storage technologies such as pumped-hydro facilities that seek to provide energy in the organized wholesale electric markets have some physical and operational characteristics that are closer to those of traditional generation than those of small electric storage resources designed primarily to provide regulation service. The optional bidding parameters that we propose here would allow electric storage resources to indicate their operational constraints to the RTO/ISO and would help these resources to manage any costs or operational constraints that they incur when transitioning between charging and discharging electricity. For example, the opportunity to submit these optional bidding parameters could allow an electric storage resource to prevent excessive variability in its operations to help optimize the services that it is available to provide and to preserve the life of the electric storage resource.

¹³⁰ We acknowledge that some of these optional bidding parameters may not be necessary for resources participating under the proposed participation model for electric storage resources that provide certain information to the RTO/ISO through telemetry.

69. Also, where the RTO/ISO has reserved for itself the right to manage the state of charge of an electric storage resource, we propose to require that the RTOs/ISOs allow electric storage resources to self-manage their state of charge and upper and lower charge limits. An electric storage resource that opts to self-manage its state of charge and upper and lower charge limits would keep its state of charge at an optimal level through its own bidding strategy, rather than the RTO/ISO market processes ensuring that dispatch does not violate its physical constraints. The Commission recently accepted revisions to the CAISO tariff that allow non-generator resources to self-manage their energy limits and state-of-charge in real-time.¹³¹

70. Of course, an electric storage resource that self-manages its state of charge is subject to any penalties for deviating from a dispatch schedule to the extent the resource manages its state of charge by deviating from the dispatch schedule. While RTOs/ISOs may be in a better position to effectively manage the state of charge for an electric storage resource that, for example, exclusively provides regulation service in the organized wholesale electric markets, some electric storage resources may be interested in providing multiple service or providing services to another party, such as to a load with which it is co-located. Affording electric storage resources the option to manage their state of charge would allow these resources to optimize their operations to provide all of

¹³¹ *California Indep. Sys. Operator, Corp.*, 156 FERC ¶ 61,110 at P 10.

the services that they are technically capable of providing, similar to the operational flexibility that traditional generators have to manage the wholesale services that they offer. However, we seek comment on whether there are conditions under which an RTO/ISO should not allow an electric storage resource to manage its state of charge and upper and lower charge limits.

71. While the inclusion of these bidding parameters would allow for more efficient use of electric storage resources, their implementation also requires the RTOs/ISOs to program these bidding parameters into their modeling and dispatch software. The difficulty of implementing these bidding parameters would likely vary from RTO/ISO to RTO/ISO. Therefore, we seek comment on the time and resources that would be necessary for the RTOs/ISOs to incorporate these bidding parameters, including the optional bidding parameters, into their modeling and dispatch software.

c. Eligibility to Participate as a Wholesale Seller and Wholesale Buyer

i. Introduction

72. The ability of electric storage resources to receive and provide electricity positions them to be both buyers and sellers in the organized wholesale electric markets. As the Commission has previously recognized, a market functions effectively only when both

supply and demand can meaningfully participate.¹³² Improving electric storage resources' opportunity to participate as both wholesale sellers of services and wholesale buyers of energy could improve market efficiency by allowing the RTO/ISO to dispatch these resources in accordance with their most economically efficient use (i.e., as supply when the market clearing price for energy is higher than their offer and as demand when the market clearing price is lower than their bid). Moreover, allowing electric storage resources to participate in the organized wholesale electric markets as dispatchable load would allow these resources, under certain circumstances, to set the price in these markets, better reflecting the value of the marginal resource and ensuring that electric storage resources are dispatched in accordance with the highest value service that they are capable of providing during a set market interval.

ii. Current Rules

73. Each RTO's/ISO's market rules that govern the eligibility of electric storage resources to participate in the organized wholesale electric markets as a demand resource are different. For example, CAISO explains that an electric storage resource interconnected to the CAISO grid with a participating generator agreement and participating load agreement can submit offers to sell and bids to buy energy in the

¹³² *Demand Response Compensation in Organized Wholesale Energy Markets*, Order No. 745, FERC Stats. & Regs. ¶ 31,322, at P 1, *order on reh'g*, Order No. 745-A, 137 FERC ¶ 61,215 (2011).

wholesale market.¹³³ According to SPP, submitting bids to purchase energy in its market is within the resource owner's discretion.¹³⁴ SPP notes that electric storage resources may submit virtual bids in the day-ahead market at any location and a fixed or price-sensitive bid at their registered load. In contrast, PJM explains that electric storage resources do not submit wholesale bids to buy electricity.¹³⁵

74. ISO-NE states that, because it is dispatchable, an electric storage resource participating as a Dispatchable Asset Related Demand resource may submit bids to buy energy in both the day-ahead and real-time energy markets; however, if it is participating as a load asset or an Asset Related Demand, it may submit bids to buy energy in the day-ahead market but would be a price taker in real-time.¹³⁶

75. MISO explains that, in the day-ahead market, electric storage resources may submit bids to buy energy at the LMP when they need to recharge as dispatchable demand or may submit virtual bids.¹³⁷ MISO further explains that in the real-time

¹³³ CAISO Response at 16.

¹³⁴ SPP Response at 7.

¹³⁵ PJM Response at 22.

¹³⁶ ISO-NE Response at 28 (citing ISO-NE Tariff, section I.2.2).

¹³⁷ MISO Response at 16.

market, most load buys energy as fixed demand and only Demand Response Resources - Type II can submit demand response offers to buy energy.

76. NYISO states that Energy Limited Resources obtain charging energy through negative MW value generation offers, rather than a bid to buy energy.¹³⁸ NYISO explains that demand-side resources participating in the Special Case Resource Program, Emergency Demand Response Program, Demand Side Ancillary Services Program, or Day-Ahead Demand Response Program do not submit bids to buy energy in the wholesale markets unless the resource is a load-serving entity, in which case it purchases its entire load. NYISO states that a demand-side resource may submit price-responsive load bids to take advantage of off-peak prices to charge its electric storage resource. NYISO adds that electric storage resources are not required to bid to buy electricity from the NYISO market, but, like any load, may bid into the day-ahead market as a price cap load bid.¹³⁹

77. The eligibility for an electric storage resource to set the price in the organized wholesale electric markets also varies among the RTOs/ISOs. For example, CAISO states that an electric storage resource that is the marginal resource may set the price of

¹³⁸ NYISO Response at 14-15.

¹³⁹ *Id.* at 15 (citing NYISO Services Tariff, section 21.1).

energy and ancillary services in CAISO's markets based on its economic bid.¹⁴⁰ PJM states that, with the exception of demand-side resources in the non-synchronized reserve market, electric storage resources may set the price as either a generation or as a demand-side resource in the capacity, energy, and ancillary service markets.¹⁴¹ SPP states that any resource, including an electric storage resource, qualified to participate in an SPP market may set the price for the relevant market.¹⁴²

78. ISO-NE states that, in each of its markets, electric storage resources may be able to set the clearing price, depending on the participation model that they are using to participate.¹⁴³ ISO-NE explains that only dispatchable resources (i.e., dispatchable generator assets and dispatchable asset related demand) may set the clearing price in the real-time energy market. ISO-NE explains that, in the day-ahead energy market, an electric storage resource may set the price by offering into the market as a generator resource, Asset Related Demand, or Dispatchable Asset Related Demand. ISO-NE adds that, by qualifying as a new generator resource or as a demand resource, an electric

¹⁴⁰ CAISO Response at 10.

¹⁴¹ PJM Response at 10.

¹⁴² SPP Response at 4.

¹⁴³ ISO-NE Response at 12-13. ISO-NE explains that, today, Real-Time Demand Response assets are price-takers in the real-time energy market but that, with the full integration of demand response into the energy market scheduled for June 1, 2018, demand response resources will have the potential to set market clearing prices.

storage resource may bid its qualified MWs into the capacity market and set the clearing price. ISO-NE notes that an electric storage resource or aggregation of electric storage resources may set the regulation market clearing prices by offering as an Alternative Technology Regulation Resource. ISO-NE states that an electric storage resource may also set the market-clearing regulation price by offering into the regulation market as a generator resource or Dispatchable Asset Related Demand.

79. MISO states that electric storage resources may set prices for products in the market(s) in which they are eligible to participate. MISO explains that, for example, an electric storage resource registered as a Load Modifying Resource may set the price in the capacity market. MISO states that an electric storage resource registered as a Stored Energy Resource may set the price for regulating reserve.¹⁴⁴

80. NYISO explains that supply offers of electric storage resources that participate as Energy Limited Resources may set the price for capacity, energy, and ancillary services; Limited Energy Storage Resources may set the price for regulation service. NYISO explains that Special Case Resources and Emergency Demand Response Program resource energy offers do not directly set the price; rather, when these resources are

¹⁴⁴ MISO Response at 10.

dispatched, the NYISO's scarcity pricing rules are triggered in the zone(s) in which they are activated and may alter energy and certain ancillary services prices.¹⁴⁵

iii. Proposed Reforms

81. We propose to require each RTO/ISO to revise its tariff to ensure that electric storage resources can be dispatched and can set the wholesale market clearing price as both a wholesale seller and wholesale buyer consistent with existing rules that govern when a resource can set the wholesale price. This proposal includes the requirements that the RTOs/ISOs accept wholesale bids from electric storage resources to buy energy so that the economic preferences of the electric storage resources are fully integrated into the market, the electric storage resource can set the price as a load resource where market rules allow, and the electric storage resource can be available to the RTO/ISO as a dispatchable demand asset. However, we note that these requirements must not prohibit electric storage resources from participating in organized wholesale electric markets as price takers, consistent with the existing rules for self-scheduled load resources. We also clarify that, while resources are not dispatched when they clear the capacity markets, we are proposing that resources using the participation model for electric storage resources be able to set the price in the capacity markets, where applicable.

¹⁴⁵ NYISO Response at 8.

82. To optimize the capabilities of electric storage resources and for the RTOs/ISOs to use them efficiently, it is important for the RTOs/ISOs to be able to symmetrically utilize the capabilities of these resources to both receive electricity from the grid and inject it back to the grid. In other words, they must be able to dispatch electric storage resources as supply when the market clearing price exceeds their offers to sell and to dispatch electric storage resources as demand when their bids to buy exceed the market clearing price. The bidirectional capabilities of electric storage resources are what make them unique, and allowing electric storage resources to participate in the organized wholesale electric markets as both wholesale sellers and wholesale buyers will help optimize the value that they provide and enhance price formation, as they will be dispatched in accordance with their most economic use.

83. We preliminarily conclude that the proposed requirement to participate as a supply and demand resource simultaneously (i.e., submit bids to buy and offers to sell during the same market interval) is necessary to maximize the value that electric storage resources can provide in the organized wholesale electric markets, allowing the markets to identify whether it is more economic to dispatch an electric storage resource as supply or demand during a given market interval. We expect that, through its bidding strategy, a resource using the electric storage resource participation model would be able to prevent any conflicting dispatch signals to itself. However, we seek comment on whether there should be a mechanism that identifies bids and offers coming from the same resource that ensures the price for the offer to sell is not lower than the price for the bid to buy during

the same market interval so that an RTO/ISO does not accept both the offer and bid of a resource using the electric storage resource participation model for that interval.

84. Generally, in the organized wholesale electric markets, resources that cannot be dispatched by the RTO/ISO do not set wholesale prices. This is because the marginal clearing prices are based on the shadow price of the next unit of incremental production, and a resource that cannot be dispatched by the RTO/ISO cannot provide that incremental unit of production. Therefore, we propose that, for a resource using the proposed participation model for electric storage resources to be able to set prices in the organized wholesale electric markets as either a wholesale seller or a wholesale buyer, it must be available to the RTO/ISO as a dispatchable resource. We believe this proposal is consistent with RTO/ISO rules on price setting and are further proposing that the ability for resources using the participation model for electric storage resources to set the price be consistent with existing rules that govern when a resource can set the wholesale price. However, we seek comment on whether any existing RTO/ISO rules may unnecessarily limit the ability of resources using the participation model for electric storage resources to set prices in the organized wholesale electric markets.

85. We note that resources using the proposed participation model for electric storage resources that elect to submit economic bids as a wholesale buyer and participate as dispatchable demand resources would still be able to self-schedule their charging and be price takers. However, it is also possible that the RTO/ISO could dispatch an electric

storage resource as load when the wholesale price for energy is above the price of their bid to buy (a circumstance under which they would lose the opportunity to earn greater revenues as a supply resource). Therefore, to help alleviate any potential financial risk to these resources when being dispatched as a demand resource, we seek comments on whether the proposed participation model for electric storage resources should allow make-whole payments when a resource participating under this participation model is dispatched as load and the price of energy is higher than the resource's bid price.

d. Minimum Size Requirement

i. Introduction

86. Depending on the technology, electric storage resources range in size from 1 kW to 1 GW,¹⁴⁶ and most of them tend to be under 1 MW.¹⁴⁷ RTO/ISO market rules may restrict electric storage resources from participating in the organized wholesale electric markets based on minimum size requirements¹⁴⁸ that may have been designed for

¹⁴⁶ Sandia Report at 29, Figure 19 (Positioning of Energy Storage Technologies).

¹⁴⁷ U.S. Department of Energy, *Grid Energy Storage* at 12 (Dec. 2013) (stating that most storage systems are in the 10 kW to 10 MW range, with the largest proportion of those resources in the 100 kW to 1 MW range).

¹⁴⁸ We use the term “minimum size requirement” to collectively describe minimum capacity requirements to qualify to use a given participation model, “minimum offer requirements” for offers to sell services in the organized wholesale electric markets, and “minimum bid requirements” for bids to buy energy in these markets. When we are referring to a specific category of minimum size requirement, we will use that specific term.

different types of resources. This is particularly true for smaller electric storage resources, which may be limited to participating in the organized wholesale electric markets as demand response resources. Such restrictions can limit these resources' ability to employ their full operational range because they are prohibited from injecting electricity into the grid in excess of their host load and preclude them from providing services such as reserves.

ii. Current Rules

87. Under existing market rules, minimum capacity, minimum offer and minimum bid requirements for electric storage resources to participate in the organized wholesale electric markets vary across the RTOs/ISOs, with minimum size requirements ranging from 100 kW to 5 MW. PJM and SPP have minimum offer requirements of 100 kW for all resources, with other RTO/ISO minimum size requirements varying across participation models and markets.¹⁴⁹

88. CAISO states that the minimum capacity requirement for demand response resources is 100 kW and that all resources other than demand response have minimum capacity requirements of 500 kW. Resources can meet these minimum capacity

¹⁴⁹ PJM Response at 10 (citing PJM Tariff, Att. DD, section 5.6); SPP Response at 5 (citing SPP Tariff, Att. AE section 1.1 (definition of "Offer")).

requirements through aggregation.¹⁵⁰ Alternatively, ISO-NE minimum capacity requirements range from 100 kW for demand response resources, to 1 MW for Alternative Technology Regulation Resources, to 5 MW for generators seeking to provide demand response in the regulation market.¹⁵¹ Under MISO tariff rules, minimum capacity requirements vary from 100 kW for Load Modifying Resources, to 1 MW for demand response resources, to 5 MW for generators.¹⁵² MISO states that it has not determined a minimum size for Stored Energy Resources but believes a minimum of 1 MW is appropriate.¹⁵³ In NYISO, the minimum size requirement is 100 kW for demand response resources and 1 MW for Energy Limited Resources and Limited Energy Storage Resources.¹⁵⁴

89. The RTOs/ISOs also define minimum bid requirements for load resources to buy energy from the organized wholesale electric markets. In CAISO, the minimum bid requirement is 10 kW, the same as for traditional generators.¹⁵⁵ In MISO and SPP, the

¹⁵⁰ CAISO Response at 10-11 (citing CAISO Tariff, App. K, Part A 1.1.1; Part B1.1; Part C1.1).

¹⁵¹ ISO-NE Response at 13-14 (citing ISO-NE Tariff, App. E2, section I-III).

¹⁵² MISO Response at 10.

¹⁵³ *Id.* at 16-17.

¹⁵⁴ NYISO Response at 9.

¹⁵⁵ CAISO Response at 16.

minimum bid requirements are 100 kW.¹⁵⁶ In ISO-NE, energy market bids cannot be smaller than 100 kW.¹⁵⁷ In NYISO, the minimum bid requirement is 1 MW, with the option to aggregate to meet that requirement.¹⁵⁸ Electric storage resources do not submit bids to buy energy in the PJM wholesale markets.¹⁵⁹

iii. Comments

90. Several commenters address the minimum size requirements to participate in the RTO/ISO markets, questioning whether the RTOs/ISOs based those standards on technological requirements and system needs. For example, NY Battery and Energy Storage Consortium argues that the minimum size requirement for participation in organized wholesale electric markets should be lowered.¹⁶⁰ Public Interest Organizations claim that minimum size requirements for electric storage resources to participate in the organized wholesale electric markets may be a barrier to distributed electric storage resources, especially those that are small. Public Interest Organizations contend that, while the opportunity to offer distributed energy resource aggregations into the markets

¹⁵⁶ MISO Response at 17; SPP Response at 8.

¹⁵⁷ ISO-NE Response at 29.

¹⁵⁸ NYISO Response at 15.

¹⁵⁹ PJM Response at 22.

¹⁶⁰ NY Battery and Energy Storage Consortium Comments at 6.

could help mitigate this concern, that opportunity is lacking or unclear in some RTOs/ISOs.¹⁶¹

91. Several commenters specifically cite the variability in the minimum size requirements of the various RTO/ISO market participation models as a barrier to electric storage resource participation. Energy Storage Association contends that minimum size requirements for electric storage resources may prohibit storage participation and lead to inconsistencies across regions.¹⁶² Advanced Energy Economy argues that it is not clear why the minimum size requirements for providing services should vary from RTO/ISO to RTO/ISO and that these market rule variations are a barrier to electric storage resource participation in the organized wholesale electric markets.¹⁶³ Public Interest Organizations assert that disparate requirements in the RTO/ISO reports indicate that some of these minimum limits may be arbitrary.¹⁶⁴

92. Other commenters identify specific minimum size requirements in certain RTO/ISO markets as barriers to the participation of electric storage resources in those markets. Minnesota Energy Storage Alliance claims that MISO's 1 MW minimum size

¹⁶¹ Public Interest Organizations Comments at 5.

¹⁶² Energy Storage Association Comments at 29.

¹⁶³ Advanced Energy Economy Comments at 10-11.

¹⁶⁴ Public Interest Organizations Comments at 5.

requirement for demand response resources is not appropriate due to the lower minimum size requirements in other RTOs/ISOs.¹⁶⁵ Minnesota Energy Storage Alliance further states that removing this requirement would allow electric storage resources to more readily participate, providing economic justification for project development and increasing MISO's operational flexibility. NY Battery and Energy Storage Consortium asserts that NYISO's 1 MW size requirement limits behind-the-meter electric storage resources from participating in NYISO's day-ahead market, despite having the technical capability to perform.¹⁶⁶

93. Solar City and Viridity ask the Commission to consider requiring all RTOs/ISOs to set a minimum requirement of 100 kW for electric storage resource participation in their markets.¹⁶⁷ Solar City argues that a 100 kW minimum size requirement will ensure that electric storage resources can provide value to markets at relatively modest levels of

¹⁶⁵ Minnesota Energy Storage Alliance notes that size restrictions do not apply to the load-modifying resource classification, but such resources are only eligible to provide capacity for MISO-declared emergency events and cannot provide energy or ancillary services. Minnesota Energy Storage Alliance Comments at 3-4.

¹⁶⁶ NY Battery and Energy Storage Consortium Comments at 5-6.

¹⁶⁷ SolarCity Comments at 9; Viridity Comments at 3.

penetration and participate in organized wholesale energy markets even when locational requirements reduce the area over which resources can be aggregated.¹⁶⁸

iv. Proposed Reforms

94. We propose that the minimum size requirement to participate in the organized wholesale electric markets under the proposed electric storage resource participation model must not exceed 100 kW. While we acknowledge that minimum size requirements may be necessary to ensure that the RTOs/ISOs can effectively model and dispatch the resources participating in their markets, large minimum size requirements create a barrier to the participation of smaller electric storage resources. We preliminarily conclude that requiring that the minimum size requirement not exceed 100 kW balances the benefits of increased competition with the ability of RTO/ISO market clearing software to effectively model and dispatch smaller resources often located on the distribution system. Thus, we propose to require each RTO/ISO to revise its tariffs to include a participation model for electric storage resources that establishes a minimum size requirement for participation in the organized wholesale electric markets that does not exceed 100 kW. This would include any minimum capacity requirements, minimum offer requirements, and minimum bid requirements for resources participating in these markets under the electric storage resource participation model.

¹⁶⁸ SolarCity Comments at 9.

e. Energy Used to Charge Electric Storage Resources

i. Introduction

95. Electric storage resources must absorb electricity (i.e., charge) to sell that electricity, net of losses, back to an RTO/ISO as energy or ancillary services. The manner in which an electric storage resource charges (consumes) energy and discharges (produces) energy will determine whether the electric storage resource is engaging in a sale for resale subject to our jurisdiction.

ii. Current Rules

96. For the most part, the RTOs/ISOs indicate that electric storage resources that are charging to later provide wholesale services in their markets already pay LMP for that electricity. CAISO states that all electric storage resources participating in its wholesale markets pay LMP for their charging energy.¹⁶⁹ ISO-NE states that electric storage resources purchasing energy directly from the wholesale market pay the LMP for the electricity they receive.¹⁷⁰ MISO states that any resources eligible to participate in MISO's capacity, energy, and ancillary service markets pay LMP for the electricity they receive.¹⁷¹ NYISO states that Energy Limited Resources using electric storage resource

¹⁶⁹ CAISO Response at 17.

¹⁷⁰ ISO-NE Response at 29-30.

¹⁷¹ MISO Response at 17.

technology and Limited Energy Storage Resources will pay the wholesale price for the electricity they consume to meet a regulation service schedule or to charge the resource if the resource is either in front-of-the-meter (a generator) or a direct NYISO customer (a load-serving entity). NYISO notes that, if the resource is behind-the-meter and served by a separate load-serving entity, then it would pay the load-serving entity's retail rate.¹⁷² PJM states that an electric storage resource would pay wholesale LMP if the resource is taking power off the system solely to inject into the energy or ancillary service markets at a later time.¹⁷³ SPP states that, in its real-time market, electric storage resources pay the real-time LMP for their load consumption, although they may also be subject to retail rules for electric consumption.¹⁷⁴

iii. Comments

97. Several commenters address the issue of the price that electric storage resources should pay for charging electricity when that electricity is for later use in the organized wholesale electric markets. For example, Alevo argues that it is not clear whether an electric storage resource connected at the distribution level will pay the LMP for its

¹⁷² NYISO Response at 16.

¹⁷³ PJM Response at 23.

¹⁷⁴ SPP Response at 7.

charging electricity, even if it is charging to provide a wholesale service.¹⁷⁵ Electric Vehicle R&D Group and NextEra contend that current RTO/ISO tariffs do not provide enough clarity on the price that storage pays for electricity,¹⁷⁶ and that the RTOs/ISOs should revise their tariffs to settle discharging and recharging resources at LMP.¹⁷⁷ Similarly, Tesla asks the Commission to clarify that electricity stored for resale is not a retail sale and thus should be settled at the wholesale LMP.¹⁷⁸

98. In contrast, Manitoba Hydro asserts that dispatchable electric storage resources should either pay a lower LMP than non-dispatchable resources or should receive a storage capacity credit for their services because a MWh received by a storage resource for later injection is different than a MWh consumed by traditional load.¹⁷⁹ Minnesota Energy Storage Alliance similarly requests that dispatchable electric storage resources pay a lower LMP or be compensated for the service.¹⁸⁰ AES Companies contend that it is

¹⁷⁵ Alevo Comments at 29.

¹⁷⁶ Electric Vehicle R&D Group Comments at 13.

¹⁷⁷ NextEra Comments at 13.

¹⁷⁸ Tesla Comments at 5-6.

¹⁷⁹ Manitoba Hydro Comments at 10-12.

¹⁸⁰ Minnesota Energy Storage Alliance Comments at 5.

inappropriate for an electric storage resource to pay LMP when it is directed to charge and that such a payment is a disincentive to new storage installation.¹⁸¹

99. SoCal Edison argues that behind-the-meter electric storage resources should not be allowed to charge at a wholesale rate and discharge to serve a retail customer to allow the retail customer to avoid paying the retail rate for its consumption.¹⁸² Addressing this concern, some commenters suggest that metering and accounting practices can be designed to delineate between wholesale and retail activities.¹⁸³

iv. Proposed Reforms

100. The Commission has found that the sale of energy from the grid that is used to charge electric storage resources for later resale into the energy or ancillary service markets constitutes a sale for resale.¹⁸⁴ As such, the just and reasonable rate for that

¹⁸¹ AES Companies Comments at 23.

¹⁸² SoCal Edison Comments at 8.

¹⁸³ Independent Energy Producers Association Comments, Att. at 7; Minnesota Energy Storage Alliance Comments at 5.

¹⁸⁴ See *Norton Energy Storage, L.L.C.*, 95 FERC ¶ 61,476, at 62,701-02 (2001) (citations omitted) (“[T]he use of compressed air as a medium for the storage of energy in an energy storage facility is a new technology. However, we find that a compressed air energy storage facility is analogous to a pumped storage hydroelectric facility, in that compressed air is used in a conversion/storage cycle just as water is used in a pumped storage hydroelectric facility in the conversion/storage cycle.... [T]he Commission views the pumping energy not as being consumed, but rather as being converted and stored, as water in the upper reservoir, for later re-conversion ... back to electric energy. It is this

(continued...)

wholesale sale of energy used to charge the electric storage resource is the RTO/ISO market's wholesale price for energy or LMP. We thus propose to require each RTO/ISO to revise its tariff to specify that the sale of energy from the organized wholesale electric markets to an electric storage resource that the resource then resells back to those markets must be at the wholesale LMP.

101. The proposed clarification also provides developers and operators of electric storage resources certainty about the price that they will be charged for purchasing charging electricity in the organized wholesale electric markets when they will use that electricity to provide wholesale services. We note that this proposed clarification is consistent with most current RTO/ISO practices as reflected in their responses.

102. We recognize SoCal Edison's concern that behind-the-meter electric storage resources should not be allowed to charge at a wholesale rate and discharge to serve a

conversion/storage cycle that distinguishes energy storage facilities, whether pumped storage hydroelectric facilities or compressed air energy storage facilities, from facilities that consume electricity (in the form of station power or otherwise). The fact that pumping energy or compression energy is not consumed means that the provision of such energy is not a sale for end use that this Commission cannot regulate. Rather, based on Norton's representations in its petition, we find that deliveries of compression energy to the Norton energy storage facility as part of energy exchange transactions employing the conversion/storage cycle are wholesale transactions subject to our exclusive authority under the FPA."). *See also PJM Interconnection, L.L.C.*, 132 FERC at 62,053 ("Like pumping energy and compression energy, the energy used to charge Energy Storage Resources will be stored for later delivery and not used for operating the electric equipment on the site of a generation facility or associated buildings as Station Power is used.").

retail customer as a means for the retail customer to avoid paying the retail rate. This situation could be even more complex if the retail customer in question also uses a behind-the-meter generator in conjunction with its storage device. Given the comments in the record indicating that metering and accounting practices can be designed to delineate between wholesale and retail activities,¹⁸⁵ we seek comment on whether such metering and accounting practices would need to be established in the RTO/ISO tariffs to facilitate compliance with this proposal or whether it is possible to determine the end use for energy used to charge an electric storage resource under existing requirements.

B. Participation of Distributed Energy Resource Aggregators in the Organized Wholesale Electric Markets

1. Introduction

103. There has been significant industry attention paid to the development of distributed energy resources and the potential for such resources to contribute to grid services. More recently, the discussion has focused on new distributed energy resources that are smaller, interconnected to lower voltage networks, and geographically dispersed. These new distributed energy resources are enabled by increasing deployment of and improvements in metering, telemetry, and communication technologies. With such advances, more localized power and energy services and more supply resources and

¹⁸⁵ Independent Energy Producers Association Comments, Att. at 7; Minnesota Energy Storage Alliance Comments at 5.

potential market participants have emerged. We are interested in removing barriers in current RTO/ISO market rules that would prevent these new, smaller distributed energy resources that are technically capable of participating in the organized wholesale electric markets from doing so.

104. As noted above, in this NOPR, we define distributed energy resources as a source or sink of power that is located on the distribution system, any subsystem thereof, or behind a customer meter.¹⁸⁶ These resources may include, but are not limited to, electric storage resources, distributed generation, thermal storage, and electric vehicles and their supply equipment.¹⁸⁷

105. As a general matter, distributed energy resources tend to be too small to participate directly in the organized wholesale electric markets on a stand-alone basis. First, they often do not meet the minimum size requirements to participate in these markets under existing participation models. Second, they may have difficulty satisfying all of the operational performance requirements of the various participation models due to their small size. Allowing these resources to participate in the organized wholesale electric markets through distributed energy resource aggregations can help to remove these barriers to their participation, providing a means for these resources to, in the aggregate,

¹⁸⁶ See *supra* note 2.

¹⁸⁷ *Id.*

satisfy minimum size and performance requirements that they could not meet on a stand-alone basis.

106. The Commission recently accepted CAISO's proposal¹⁸⁸ to allow distributed energy resource aggregations in its markets. In addition, the RTOs/ISOs have implemented some models for aggregated resources to participate in their organized wholesale electric markets. These are described in more detail below but are generally for demand response resources, with a few exceptions. As a result, the majority of distribution-connected electric storage and other distributed energy resources that seek to access the organized wholesale electric markets must do so by participating as behind-the-meter demand response. While these demand response programs have helped reduce barriers to load curtailment resources, they often limit the operations of other types of distributed energy resources, such as electric storage or distributed generation, as well as the services that they are eligible to provide.

2. Current Rules

107. The RTOs/ISOs describe the opportunities for electric storage resources connected to the distribution system and electric storage resource aggregations to participate in their capacity, energy, and ancillary service markets. CAISO supports the aggregation of distributed energy resources, including storage, seeking to participate in the CAISO

¹⁸⁸ See *California Indep. Sys. Operator Corp.*, 155 FERC ¶ 61,229.

markets.¹⁸⁹ In addition, CAISO states that electric storage resources that wish to aggregate into a resource that can participate in the wholesale markets can participate by providing load curtailment as Proxy Demand Resources or Reliability Demand Response Resources.¹⁹⁰

108. ISO-NE explains that, under each participation model, a single resource may be composed of multiple resources if those resources are either physically in the same location or require coordinated control.¹⁹¹ ISO-NE explains that Alternative Technology Regulation Resources may include aggregations of multiple end-use customers, each with less than 1 MW of regulation capacity.¹⁹² ISO-NE adds that Asset Related Demands may be aggregated if they are served by the same point of electrical connection and meet a 1 MW threshold.¹⁹³

109. ISO-NE states that electric storage resources that meet its definition of Distributed Generation (i.e., behind-the-meter resources with an aggregate nameplate capacity of less

¹⁸⁹ CAISO Response at 2-3. *See also California Indep. Sys. Operator Corp.*, 155 FERC ¶ 61,229.

¹⁹⁰ CAISO Response at 7.

¹⁹¹ ISO-NE Response at 26 (citing ISO-NE Operating Procedure 14, section II.A).

¹⁹² *Id.* (citing ISO-NE Tariff, section III.14.2(c)).

¹⁹³ *Id.* at 27 (citing ISO-NE Operating Procedure 14, section I.2.2).

than 5 MW or the demand of the end-use customer, whichever is greater) may qualify as Real-Time Demand Response Assets, which allows for participation in the forward capacity market, the transitional price-responsive demand program, and the regulation market if it is also registered as an Alternative Technology Regulation Resource.¹⁹⁴ ISO-NE explains that, for the capacity market, demand resources may consist of an aggregation of multiple end-use customers, though they must be at least 100 kW and located within a dispatch zone or load zone as required under the participation model through which they are participating.¹⁹⁵ ISO-NE further explains that for the energy and reserve markets, demand response resources may also be aggregated as long as they are individually at least 10 kW, have an expected maximum interruptible capacity of 5 MW or less, and are located within a dispatch zone and reserve zone.¹⁹⁶

110. MISO states that Stored Energy Resources and Demand Response Resources – Type II are allowed to aggregate under a single elemental pricing node. MISO adds that Demand Response Resources – Type I and Load Modifying Resources are allowed to aggregate within one local balancing authority.¹⁹⁷

¹⁹⁴ *Id.* at 6-7.

¹⁹⁵ *Id.* at 27 (citing ISO-NE Operating Procedure 14, section III.13.1.4.1).

¹⁹⁶ *Id.* (citing ISO-NE Operating Procedure 14, section III.E2.1.1).

¹⁹⁷ MISO Response at 15.

111. NYISO states that aggregated resources can participate in the Emergency Demand Response Program, Day-Ahead Demand Response Program, Demand Side Ancillary Services Program, and Special Case Resource Programs. NYISO notes that aggregated electric storage resources may be used to generate demand reductions in any of those programs.¹⁹⁸

112. PJM states that aggregated electric storage resources can participate in the capacity, energy, and ancillary service markets. In the capacity market, PJM states that demand-side resources can be aggregated to provide load reductions.¹⁹⁹ Under PJM's capacity performance proposal, electric storage resources are eligible to aggregate with other electric storage resources, Intermittent Resources, Demand Resources, Energy Efficiency Resources, and Environmentally-Limited Resources to provide capacity.²⁰⁰ In the PJM regulation market, PJM states that all resources, including electric storage resources, may elect to be part of a performance group for the purpose of improving their overall performance score.²⁰¹ In the PJM energy market, PJM adds that multiple batteries

¹⁹⁸ NYISO Response at 13.

¹⁹⁹ PJM Response at 20 (citing PJM Tariff, Attachment DD, sections 11, 11A).

²⁰⁰ *Id.* (citing PJM Tariff, Attachment DD, section 5.6.1(h)).

²⁰¹ *Id.* at 20-21 (citing PJM Manual 12, section 4.5.7).

located behind a single node and owned by the same entity would be eligible to offer into the energy market as one resource.²⁰²

113. SPP states that resources at the same point of injection may register at the unit or plant level and electric storage resources may be aggregated if the resources are electrically equivalent from the transmission system perspective (i.e., use the same point of injection).²⁰³

3. Comments

114. Many commenters note that it is important for distributed energy resources to be allowed to fully participate in organized wholesale electric markets. For example, Advanced Energy Economy contends that, absent legitimate technical needs, distributed energy resources should be allowed to fully participate in organized wholesale electric markets.²⁰⁴ Advanced Energy Economy claims that certain RTOs/ISOs have excluded these resources through artificial classifications (e.g., the inability of multiple behind-the-meter generation and electric storage resources to provide frequency regulation in PJM). Similarly, SolarCity asks the Commission to require RTOs/ISOs to revise or implement

²⁰² *Id.* at 21.

²⁰³ SPP Response at 7.

²⁰⁴ Advanced Energy Economy Comments at 16-18.

rules to ensure that behind-the-meter resources, including electric storage resources, have a clear path for participation in all wholesale energy markets.²⁰⁵

115. Energy Storage Association agrees that distribution-connected electric storage resources, including aggregation across multiple storage assets and sites, should be able to participate in the organized wholesale electric markets to enhance competition needed for just and reasonable rates.²⁰⁶ Energy Storage Association asks the Commission to consider extending the best practices learned in CAISO to all organized wholesale electric markets to address common barriers in metering, telemetry, and resource eligibility. RES Americas supports Energy Storage Association's comments and encourages the Commission to investigate the barriers to the participation of distributed energy resources in organized wholesale electric markets.²⁰⁷ NY Battery and Energy Storage Consortium argues that behind-the-meter energy storage resources should be able to participate in organized wholesale electric markets directly or in aggregate form, and points out that behind-the-meter storage participating in NYISO as a demand side

²⁰⁵ SolarCity Comments at 4.

²⁰⁶ Energy Storage Association Comments at 30 (citing *California Indep. Sys. Operator Corp.*, 155 FERC ¶ 61,229).

²⁰⁷ RES Americas Comments at 4-5.

ancillary services program resource is not allowed to bid into the day-ahead demand response market, even though it is technically capable of doing so.²⁰⁸

116. Some commenters cite the inability for distributed energy resources to inject energy when participating as demand response as a barrier to distributed energy resources. SolarCity states that this inability hinders the ability of behind-the-meter resources to provide energy services and limits their capacity.²⁰⁹ Advanced Energy Economy and Solar Grid Storage argue that PJM's restriction on the injection of energy past a customer's retail meter during operations for providing ancillary services in its markets is a barrier to electric storage resources.²¹⁰ Energy Storage Association and NextEra argue that no RTO/ISO allows behind-the-meter storage to net inject power to provide wholesale generator services.²¹¹ NextEra agrees that this prohibition effectively limits the size of electric storage resources designed for customer applications. Energy Storage Association notes that NYISO recently received the Commission's conditional acceptance of its behind-the-meter net generator enhancement, but Energy Storage Association asserts that it still effectively excludes participation of electric storage

²⁰⁸ NY Battery and Energy Storage Consortium Comments at 6.

²⁰⁹ SolarCity Comments at 4.

²¹⁰ Advanced Energy Economy Comments at 16-17; Solar Grid Storage Comments at 2.

²¹¹ Energy Storage Association Comments at 29; NextEra Comments at 12.

resources because it does not include electric storage functionality (e.g., state of charge management).²¹²

117. Other comments focus on the benefits of allowing distributed energy resources to participate in the organized wholesale markets as aggregations. RES Americas contends that aggregation of electric storage resources, either within the asset class or across other resources that can be limited in their ability to offer a breadth of market products (i.e., renewables or demand response), could be a means to realize market efficiencies and other policy objectives without creating entirely new market products or otherwise disrupting grid operations.²¹³ Electric Vehicle R&D Group states that third-party aggregators are the most practical approach to utilizing distributed electric storage resources connected to the low- and medium-voltage system.²¹⁴ Electric Vehicle R&D Group argues that, given the value that distributed electric storage resources provide to both transmission and distribution system operators and the lack of technical abilities of a distribution system operator to-date to build, qualify, and cost-effectively operate a distributed storage system aggregator, rules should not prohibit third-party aggregators or require distribution operators to manage them. Electric Vehicle R&D Group adds that

²¹² Energy Storage Association Comments at 29-30.

²¹³ RES Americas Comments at 5.

²¹⁴ Electric Vehicle R&D Group Comments at 2.

the Commission should allow third-party aggregators to provide service to both RTOs and distribution system operators.

118. National Electrical Manufacturers Association states that organized wholesale electric markets should accommodate aggregated electric storage resources, including electric storage resources installed behind-the-meter, without imposing excessive requirements that would preclude the participation of smaller resources (e.g., arduous study processes and/or expensive data telemetry requirements).²¹⁵ Similarly, NY Battery and Energy Storage Consortium argues that NYISO should avoid creating metering and telemetry requirements with prohibitively high transaction costs and imposing undue burdens on behind-the-meter storage participation.²¹⁶ Energy Storage Association agrees that metering and telemetry requirements and interconnection processes can pose prohibitively high transaction costs for the small project sizes that characterize behind-the-meter electric storage resources, creating undue burdens on their participation in most RTOs/ISOs.²¹⁷

²¹⁵ National Electrical Manufacturers Association Comments at 5.

²¹⁶ NY Battery and Energy Storage Consortium Comments at 6.

²¹⁷ Energy Storage Association Comments at 29.

119. Similarly, California Energy Storage Alliance claims that the overhead costs of registering individual resources within an aggregation can be burdensome and costly.²¹⁸ Specifically, California Energy Storage Alliance argues that the registration of individual customer sites with load-serving entities, the California Public Utilities Commission, and CAISO can impose significant costs that discourage participation as proxy demand response and other wholesale market resources. California Energy Storage Alliance asserts that a separate administrative process under a behind-the-meter electric storage resource-specific model, or a streamlined version under existing constructs, could reduce these administrative costs by standardizing forms and processes across all individual resources and allowing the submission of a single application.

120. Some commenters identify problems with opportunities for aggregations in the RTOs/ISOs. Energy Storage Association is concerned that aggregated distributed energy resources are not permitted to offer into some RTO/ISO markets, while it is not clear how they can offer into others.²¹⁹ Energy Storage Association claims that market rules present barriers to aggregation (particularly minimum size requirements) because they are often designed around individual sites as a resource, rather than the capabilities of an

²¹⁸ California Energy Storage Alliance Comments at 7.

²¹⁹ Energy Storage Association Comments at 29 (citing ISO-NE Response at 26; NYISO Response at 13).

aggregated set of sites.²²⁰ NextEra asserts that, to enable aggregators to participate effectively in the organized wholesale electric markets, more work is needed by the RTOs/ISOs, like the recent CAISO initiative that led to new aggregation opportunities for small distributed resources.²²¹

121. Public Interest Organizations agree that the opportunity to aggregate distributed energy resources could help mitigate minimum size or duration requirements, but state that this opportunity is lacking or unclear in some RTOs/ISOs.²²² NY Battery and Energy Storage Consortium and NY Transmission Owners point out that NYISO rules do not allow smaller resources with a capacity less than 1 MW to aggregate and provide generation above their host loads, though they can participate as an aggregated demand response resource.²²³ Similarly, Minnesota Energy Storage Alliance states that MISO's market rules prevent robust participation of distributed electric storage resources in its energy and ancillary service markets because they do not permit the aggregation of these

²²⁰ *Id.* at 27-28.

²²¹ NextEra Comments at 12-13 (citing *California Indep. Sys. Operator Corp.*, 155 FERC ¶ 61,229 at P 60).

²²² Public Interest Organizations Comments at 5.

²²³ NY Battery and Energy Storage Consortium Comments at 6; NY Transmission Owners Comments at 3 (citing NYISO Installed Capacity Manual at 108, 110).

resources to meet the 5 MW minimum capacity requirement for a Demand Response Resource.²²⁴

122. Solar Grid Storage states that, while PJM’s 100 kW minimum size requirement to participate in its ancillary service markets allows electric storage resources to aggregate their dispatch, aggregated resources must be part of a “performance group” in the same location.²²⁵ Solar Grid Storage asserts that, because some ancillary services like frequency regulation are not site specific and can be provided with equal value to PJM over vastly different areas within the ISO, this locational restriction is unreasonable.

123. Some commenters stress the need to ensure that grid reliability concerns are addressed in rules governing behind-the-meter resources, including aggregations of such resources. EEI states that, because behind-the-meter resources are interconnected to the distribution grid and ultimately impact the transmission system, EEI members are interested in ensuring that any actions the RTOs/ISOs take to allow these resources, including aggregated resources, to participate in the organized wholesale electric markets do not negatively affect the electric distribution company’s ability to maintain the reliability of the distribution system.²²⁶ EEI claims that electric distribution utilities need

²²⁴ Minnesota Energy Storage Alliance Comments at 4.

²²⁵ Solar Grid Storage Comments at 4.

²²⁶ EEI Comments at 5.

to have visibility and input/control of the resources that are integrated to the distribution system for planning and operating purposes. SoCal Edison states that safety and reliability needs must take precedence over wholesale market dispatch and asks the Commission to consider the safe and reliable operation of the distribution system as a key principle when addressing the participation of distribution system-connected electric storage resources in the organized wholesale electric markets.²²⁷

4. Proposed Reforms

124. We are interested in removing barriers in current RTO/ISO market rules that would prevent these new, smaller distributed energy resources that are technically capable of participating in the organized wholesale electric markets from doing so. It is clear from the comments that the ability to meaningfully participate in the organized wholesale electric markets for these smaller distributed energy resources is through aggregations. Thus, we propose to require each RTO/ISO to revise its tariff as necessary to allow distributed energy resource aggregators to offer to sell capacity, energy, and ancillary services in the organized wholesale electric markets. Specifically, we propose to require each RTO/ISO to revise its tariff to define distributed energy resource aggregators as a type of market participant that can participate in the organized wholesale electric markets under the participation model that best accommodates the physical and

²²⁷ SoCal Edison Comments at 2, 5-6.

operational characteristics of its distributed energy resource aggregation. This proposal is similar to CAISO's market rules that establish a distributed energy resource provider as a new type of market participant.²²⁸ Our proposal would expand the types of resources that are eligible to participate in the organized wholesale electric markets through aggregators and require the RTOs/ISOs to remove any unnecessary limitations on how the distributed energy resources that participate in such aggregations must be operated.

125. Distributed energy resources may be unable or unwilling to participate in the organized wholesale electric markets absent the opportunity to participate as part of a distributed energy resource aggregation. Distributed energy resources are generally smaller than other resources connected to the grid and therefore may be unable to meet all of the qualification or performance requirements for participation in the organized wholesale electric markets. Specifically, they may be too small to satisfy minimum size requirements on a stand-alone basis and, as small resources, may face operational constraints that prevent them from satisfying minimum performance requirements.²²⁹ However, if these distributed energy resources were permitted to aggregate with other distributed energy resources to participate in the organized wholesale electric markets,

²²⁸ See, e.g., *California Indep. Sys. Operator Corp.*, 155 FERC ¶ 61,229 at PP 3-7.

²²⁹ For example, combining the discharge times of multiple electric storage resources and/or combining them with distributed generation resources could allow aggregated resources to meet minimum run-time requirements that individual electric storage resources may not be able to meet.

they may be able to, in the aggregate, meet any minimum size and performance requirements, particularly if the operational characteristics of different distributed energy resources in a given distributed energy resource aggregation complement each other.

126. Distributed energy resource aggregations will also help to address the commercial and transactional barriers to distributed energy resource participation in the organized wholesale electric markets. Owners and operators of individual distributed energy resources may be reluctant to incur the significant costs of participating in the organized wholesale electric markets, such as the costs of the necessary metering, telemetry and communication equipment. The smaller a resource is, the more likely the transaction costs to sell services into the organized wholesale electric markets outweigh the benefits that the prospective market participant may realize from selling wholesale services. However, some of these costs can be reduced by participating in the organized wholesale electric markets through a distributed energy resource aggregation, for example the time and resources necessary to learn the market rules and actively submit bids and/or offers into the organized wholesale electric markets.

127. We also believe that some of the restrictions placed on aggregators in the RTOs/ISOs, such as the types of resources that can participate in those aggregations and the inability to inject energy onto the grid, may limit the operation and effectiveness of existing RTO/ISO programs for aggregations. Therefore, as discussed further below, we propose to expand the types of distributed energy resources that are eligible to participate

in the organized wholesale electric markets through aggregators and require RTOs/ISOs to remove any unnecessary limitations on how the distributed energy resources that participate in such aggregations must be operated.

128. Our proposal requires the RTOs/ISOs to define distributed energy resource aggregators as a type of market participant that can participate in the organized wholesale electric markets under the participation model that best accommodates the physical and operational characteristics of its distributed energy resource aggregation. This proposed requirement means that the distributed energy resource aggregator would register as, for example, a generation asset if that is the participation model that best reflects its physical characteristics. While we expect efficiencies to be gained by allowing distributed energy resources aggregations to participate under existing participation models, we also acknowledge that the use of existing participation models may not be possible in every RTO/ISO based on how market participation is structured. However, where this is possible, we emphasize that the distributed energy resource aggregation must still satisfy any eligibility requirements of the applicable participation model before it can participate in the organized wholesale electric markets under that participation model. Therefore, to accommodate the participation of distributed energy resource aggregations under the various participation models, we propose that each RTO/ISO modify the eligibility requirements for existing participation models as necessary to allow for the participation of distributed energy resource aggregators.

129. The costs of distributed energy resources have decreased significantly,²³⁰ which when paired with alternative revenue streams and innovative financing solutions, is increasing these resources' potential to compete in and deliver value to the organized wholesale electric markets. Moreover, integrating these resources' capabilities into the organized wholesale electric markets will help the RTOs/ISOs to account for their impacts on installed capacity requirements and day-ahead energy demand, thereby reducing uncertainty in load forecasts and reducing the risk of over procurement of resources and the associated costs.

130. We believe that our proposal will provide numerous supplementary benefits to the RTO/ISO systems. For example, by removing barriers to the participation of distributed energy resources in organized wholesale electric markets through aggregators, these resources may locate where price signals indicate that new capacity is most needed, potentially helping to alleviate congestion and congestion costs during peak load conditions and to reduce transmission investment costs for transmitting energy into persistently high-priced load pockets. Moreover, unlike larger fossil fuel generators that often are not able to locate in load pockets due to environmental or other citing concerns, distributed energy resources are more able to co-locate with load and provide associated

²³⁰ See, e.g., *Revolution... No, The Future Arrives for Five Clean Energy Technologies*, 2016 Update, at 1; and *Tracking the Sun VIII*, Lawrence Berkeley National Lab, at 15 (Aug. 2015).

benefits. We also believe that the shorter lead time to develop many forms of distributed energy resources compared to traditional generators or transmission lines allows them to rapidly respond to near-term generation or transmission reliability-related requirements, further improving their ability to enhance reliability and reduce system costs.

131. Additionally, we agree with the comments of Advanced Energy Economy and Public Interest Organizations that electric storage resources and other resources connected to the distribution system should be able to participate in all of the organized wholesale electric markets in which they are technically capable of participating and that barriers that unnecessarily prevent distributed energy resources from providing certain services may be caused by market rules that are unduly discriminatory. The most commonly cited example of these barriers to participation in the comments we received are market rules that relegate electric storage resources, particularly behind-the-meter electric storage resources, to market participation using demand response programs. We agree with commenters that existing RTO/ISO demand response programs may restrict the ability of electric storage and other distributed energy resources from providing the full suite of services that they are capable of providing, and therefore propose this alternative path for distributed energy resources to access the organized wholesale electric markets.

132. As such, we propose to require each RTO/ISO to revise its tariff to allow distributed energy resource aggregators to participate directly in the organized wholesale

electric markets and to establish market rules to accommodate the participation of distributed energy resource aggregations, consistent with the following:

- a. Eligibility to participate in the organized wholesale electric markets through a distributed energy resource aggregator;
- b. Locational requirements for distributed energy resource aggregations;
- c. Distribution factors and bidding parameters for distributed energy resource aggregations;
- d. Information and data requirements for distributed energy resource aggregations;
- e. Modifications to the list of resources in a distributed energy resource aggregation;
- f. Metering and telemetry system requirements for distributed energy resource aggregations;
- g. Coordination between the RTO/ISO, the distributed energy resource aggregator, and the distribution utility; and
- h. Market participation agreements for distributed energy resource aggregators.

a. **Eligibility to Participate in the Organized Wholesale Electric Markets through a Distributed Energy Resource Aggregator**

133. We preliminarily find that limiting the types of technologies that are allowed to participate in the organized wholesale electric markets through distributed energy resource aggregator would create a barrier to entry for emerging or future technologies, potentially precluding them from being eligible to provide all of the capacity, energy and ancillary services that they are technically capable of providing. While some individual

resources or certain technologies may not be able to meet the qualification or performance requirements to provide services to the organized wholesale electric markets on their own, they may satisfy such requirements as part of a distributed energy resource aggregation where resources complement one another's capabilities.²³¹ To help ensure that the market rules that the RTOs/ISOs develop to comply with any Final Rule issued in this proceeding are sufficiently flexible to accommodate the participation of new distributed energy resources as technology continues to evolve and to acknowledge the potential for distributed energy resources to satisfy qualification or performance requirements through a distributed energy resource aggregator, we propose that each RTO/ISO revise its tariff so that it does not prohibit the participation of any particular type of technology in the organized wholesale electric markets through a distributed energy resource aggregator. However, to the extent existing rules or regulations explicitly prohibit certain technologies from participating in the organized wholesale electric markets, we do not intend to overturn those rules or regulations.

134. We also propose that it is appropriate for each RTO/ISO to limit the participation of resources in the organized wholesale electric markets through a distributed energy resource aggregator that are receiving compensation for the same services as part of

²³¹ Combining electric storage resources with distributed generation could allow the aggregate resource to achieve performance requirements (such as minimum run times) that an electric storage resource could not meet on its own and provide services (such as regulation) that distributed generation may not be able to provide on its own.

another program. Since resources able to register as part of a distributed energy resources aggregation will be located on the distribution system, they may also be eligible to participate in retail compensation programs, such as net metering, or other wholesale programs, such as demand response programs. Therefore, to ensure that there is no duplication of compensation, we propose that distributed energy resources that are participating in one or more retail compensation programs such as net metering or another wholesale market participation program will not be eligible to participate in the organized wholesale electric markets as part of a distributed energy resource aggregation.

135. With respect to the capacity of the individual distributed energy resources that can participate in the wholesale electric markets through a distributed energy resource aggregator, we propose not to establish a minimum or maximum capacity requirement. We believe participation in the organized wholesale electric markets through a distributed energy resource aggregator should not be conditioned on the size of the resource, but we recognize that existing organized wholesale electric market rules may require resources to meet certain minimum or maximum capacity requirements under certain participation models. Therefore, we seek comment on whether we should establish a minimum or maximum capacity limit for individual resources seeking to participate in the organized wholesale electric markets through a distributed energy resource aggregator, or whether we should allow each RTO/ISO to propose such a minimum or maximum capacity requirement on compliance with any Final Rule issued in this rulemaking proceeding. To the extent that commenters think that we should adopt a minimum or maximum capacity

requirement for individual distributed energy resources participating in the organized wholesale markets through a distributed energy resource aggregator, we seek comment on what that requirement should be.

136. With respect to the size of the distributed energy resource aggregations themselves, we propose that these aggregations meet any minimum size requirements of the participation model under which they elect to participate in the organized wholesale electric markets. For example, if a distributed energy resource aggregator decides to register using the participation model for electric storage resources proposed above given the cumulative physical and operational characteristics of the distributed energy resources in its aggregation, then its distributed energy resource aggregation would be required to meet the 100 kW minimum size requirement we propose for that participation model. Alternatively, if the distributed energy resource aggregator decides to register as a generator, then its aggregation would be required to meet the minimum size requirement for the generator participation model in the relevant RTO/ISO market. We seek comment on this proposal to require distributed energy resource aggregations to meet the minimum size requirements of the participation model that they use to participate in the organized wholesale electric markets.

137. Consistent with Order No. 719, we also propose that each RTO/ISO revise its tariff to allow a single qualifying distributed energy resource to avail itself of the

proposed distributed energy resource aggregation rules by serving as its own distributed energy resource aggregator.²³²

b. Locational Requirements for Distributed Energy Resource Aggregations

138. Some RTO/ISO market rules permit only those resources that are located behind the same point of interconnection or at a single pricing node to aggregate. These limitations could be the result of several concerns. For instance, an RTO/ISO may be concerned that geographically dispersed resources participating in the organized wholesale electric markets through a distributed energy resource aggregation may exacerbate a transmission constraint or otherwise cause a reliability concern if dispatched as a single resource by the RTO/ISO. Similarly, an RTO/ISO may be concerned about price formation for services with geographically specific prices if geographically dispersed resources participating in the organized wholesale electric markets through a distributed energy resource aggregation were dispatched as a single resource by the RTO/ISO. That said, we are concerned that some existing requirements for aggregations to be located behind a single point of interconnection or pricing node may be overly stringent and may unnecessarily restrict the opportunities for distributed energy resources to participate in the organized wholesale electric markets through a distributed energy

²³² See Order No. 719, FERC Stats. & Regs. ¶ 31,281 at P 158(d) (“An [aggregator of retail customers] can bid demand response either on behalf of only one retail customer or multiple retail customers.”).

resource aggregator. We also note that recent improvements in metering, telemetry, and communication technology should facilitate better situational awareness and enable management of geographically disperse distributed energy resource aggregations, potentially rendering such restrictive locational requirements unnecessary.

139. Therefore, we propose to require each RTO/ISO to revise its tariff to establish locational requirements for distributed energy resources to participate in a distributed energy resource aggregation that are as geographically broad as technically feasible. Our proposal would give each RTO/ISO flexibility to adopt locational requirements that both allow for the participation of geographically disperse distributed energy resources in the organized wholesale electric markets through a distributed energy resource aggregation, where technically feasible, and account for the modeling and dispatch of the RTO's/ISO's transmission system. We further acknowledge that the appropriate locational requirements may differ based on the services that a distributed energy resource aggregator seeks to provide (e.g., the locational requirements for participation in the day-ahead energy market may differ from those for participation in the ancillary service markets).

140. To the extent that commenters would prefer that we require the RTOs/ISOs to adopt consistent locational requirements, we seek further comment on what locational requirements we could require each RTO/ISO to adopt that would allow distributed energy resources to be aggregated as widely as possible without threatening the reliability

of the transmission grid or the efficiency of the organized wholesale electric markets.

We note that, in some RTOs/ISOs and for some services, the only geographic limitations imposed on distributed energy resource aggregations are by zone or due to modeled transmission constraints.²³³

141. We seek comment on potential concerns about dispatch, pricing, or settlement that the RTOs/ISOs must address if the distributed energy resources in a particular distributed energy resource aggregation are not limited to the same pricing node or behind the same point of interconnection. We also note that, as discussed in Section III.B.4.g, we propose to allow the relevant distribution utility or utilities to review the list of distributed energy resources in a distributed energy resource aggregation, which will also help ensure that dispatch of the aggregated distributed energy resources as a single resource will not cause any reliability concerns.

²³³ See, e.g., CAISO Tariff, Att. A, section 4.17.3 (e) (“Each Distributed Energy Resource Aggregation must be located in a single Sub-LAP.”). CAISO defines a sub-LAP as a subset of pricing nodes within a default load aggregation point. See CAISO Tariff, Appendix A, Master Definitions and Supplement. See also NYISO Market Administration and Control Area Service Tariff, section 2.4 (Definitions – D) (“Demand Side Ancillary Service Program Resource (DSASP Resource): A Demand Side Resource or an aggregation of Demand Side Resources located in the [New York Control Area (NYCA)] with at least 1 MW of load reduction that is represented by a point identifier (PTID) and is assigned to a Load Zone or Subzone by the ISO....”); NYISO Day-Ahead Demand Response Program Manual at 2.16.4 (“A process and procedures will be drawn to...set limits to aggregation projects by zone, provider, program, or any other category.”).

**c. Distribution Factors and Bidding Parameters for
Distributed Energy Resource Aggregations**

142. RTOs/ISOs need to know which resources in a distributed energy resource aggregation will be responding to their dispatch signals and where those resources are located. This information is particularly important if the resources in a distributed energy resource aggregation are located across multiple points of interconnection, multiple transmission or distribution lines, or multiples nodes on the grid.

143. We, therefore, propose that the market rules governing distributed energy resource aggregations allow the RTOs/ISOs to require sufficient information from the resources in a distributed energy resource aggregation to reliably operate their systems. Specifically, we propose to require each RTO/ISO to revise its tariff to include the requirement that distributed energy resource aggregators (1) provide default distribution factors²³⁴ when they register their distributed energy resource aggregation and (2) update those distribution factors if necessary when they submit offers to sell or bids to buy into the organized wholesale electric markets. In turn, we propose to require each RTO/ISO to revise the bidding parameters for each participation model in its tariff to allow distributed energy resource aggregators to update their distribution factors when participating in the organized wholesale electric markets. In addition to comments on this proposal, we seek

²³⁴ For purposes of this NOPR, distribution factors indicate how much of the total response from a distributed energy resource aggregation would be coming from each pricing node at which one or more resources participating in the aggregation are located.

comment on alternative approaches that may provide the RTOs/ISOs with the information from geographically or electrically disperse resources in a distributed energy resource aggregation necessary to reliably operate their systems.

144. Moreover, we preliminarily find that the bidding parameters for each participation model in the RTO/ISO tariffs may have to account for the physical and operational characteristics of distributed energy resource aggregations. Therefore, we seek comment on whether bidding parameters in addition to those already incorporated into existing participation models may be necessary to adequately characterize the physical or operational characteristics of distributed energy resource aggregations.

d. Information and Data Requirements for Distributed Energy Resource Aggregations

145. The RTOs/ISOs need sufficient information about the distributed energy resource aggregation and the individual resources in a distributed energy resource aggregation to effectively model, dispatch, and settle the aggregation. We preliminarily find that the information and data requirements that apply to distributed energy resource aggregations must not pose barriers to the participation of small distributed energy resources or distributed energy resources relying on any specific technology in the organized wholesale electric markets through a distributed energy resource aggregator. We refer to information and data requirements as the information that the distributed energy resource aggregator is required to provide to the RTO/ISO when the distributed energy resource aggregator and its list of resources register as a market participant as well as the

information and data necessary for settlement and auditing purposes. In this NOPR, we seek to balance the information needs of RTOs/ISOs with information requirements so burdensome that they could limit the benefit of these proposed changes. The RTO/ISO will require certain information for the distributed energy resource aggregation as a whole, as well as the individual resources in the aggregation. While some of this information may be replicated in bidding parameters, we propose that the distributed energy resource aggregator initially provide to the RTO/ISO a description of the physical parameters of the distributed energy resource aggregation, including (1) the total capacity; (2) the minimum and maximum operating limits; (3) the ramp rate; (4) the minimum run time; and (5) the default distribution factors, if applicable. We propose to require each RTO/ISO to revise its tariff to require distributed energy resource aggregators to provide the RTO/ISO with a list of the distributed energy resources in the distributed energy resource aggregation that includes information about each of those distributed energy resources, including each resource's capacity, location on the distribution system, and its operating limits.

146. Electric Vehicle R&D Group identifies PJM's requirement for resources in a distributed energy resource aggregation to provide a one-line diagram of the resource as too cumbersome, especially for small resources at residential locations.²³⁵ Additionally,

²³⁵ Electric Vehicle R&D Group Comments at 8-9.

in CAISO's distributed energy resource provider filing, CAISO declined to require renewable generation resources in an aggregation to provide the same meteorological data that standalone intermittent generators are required to provide because they believed the requirement would create an undue burden on individual distributed energy resources.²³⁶ We agree that certain information requirements may be so burdensome for individual distributed energy resources that they pose a barrier to the participation of these distributed energy resources in the organized wholesale electric markets through aggregations. We therefore seek comment on whether there are information and data requirements imposed by RTOs/ISOs that apply to other market participants that should not apply to individual distributed energy resources participating in the organized wholesale electric markets through a distributed energy resource aggregation.

147. We also propose to require each RTO/ISO to revise its tariff to require distributed energy resource aggregators to maintain aggregate settlement data for the distributed energy resource aggregation so that the RTO/ISO can regularly settle with the distributed energy resource aggregator for its market participation. Finally, we propose to require distributed energy resource aggregators to maintain data for a length of time consistent with the RTO's/ISO's auditing requirements, for each individual resource in its distributed energy resource aggregation so that each resource can verify its performance

²³⁶ See CAISO Transmittal Letter, Docket No ER16-1085-000, at 22. (Mar. 4, 2016).

if audited. We seek comment on these proposed data requirements and on whether distributed energy resource aggregators should be required to provide additional data to the RTO/ISO.

e. Modifications to the List of Resources in a Distributed Energy Resource Aggregation

148. The requirements for a distributed energy resource aggregator associated with modifications to the list of resources in a distributed energy resource aggregation can present a barrier to the participation of distributed energy resource aggregations in the organized wholesale electric markets. Electric Vehicle R&D Group notes that, to modify its distributed energy resource aggregation in PJM, it has to un-register all resources in its aggregation and then re-run the testing protocol for the revised aggregation to re-qualify to participate in the PJM markets.²³⁷ Electric Vehicle R&D Group argues that testing every incremental addition to an aggregation is unnecessary because they are required to continuously report their available capacity and meter their aggregate power response. Because the incremental impacts on the organized wholesale electric markets of the addition or removal of individual distributed energy resources from a distributed energy resource aggregation will likely be minimal, and they are short lead time resources that can be developed and built quickly, we preliminarily conclude that they should be able to

²³⁷ Electric Vehicle R&D Group Comments at 9.

enter and exit distributed energy resource aggregations participating in the organized wholesale electric markets without undue burden.

149. We therefore propose that each RTO/ISO revise its tariff to allow a distributed energy resource aggregator to modify the list of resources in its distributed energy resource aggregation without reregistering all of the resources if the modification will not result in any safety or reliability concerns. We emphasize, however, pursuant to the proposed requirements in Section III.B.4.g below, that the relevant distribution utility or utilities must have the opportunity to review the list of individual resources that are located on their distribution system in a distributed energy resource aggregation before those resources may participate in the organized wholesale electric markets through the aggregation, so that they can assess whether the resources would be able to respond to RTO/ISO dispatch instructions without posing any significant risk to the distribution system.

f. Metering and Telemetry System Requirements for Distributed Energy Resource Aggregations

150. While the distributed energy resources in an aggregation will need to be directly metered, the metering and telemetry system, i.e., hardware and software, requirements RTOs/ISOs impose on distributed energy resource aggregators and individual resources in distributed energy resource aggregations can pose a barrier to the participation of these aggregations in organized wholesale electric markets. We recognize that RTOs/ISOs need metering data for settlement purposes, and telemetry data to determine a resource's

real-time operational capabilities so that they can efficiently dispatch resources.

However, metering and telemetry systems are often expensive potentially creating a burden for small distributed energy resources. While telemetry data about a distributed energy resource aggregation as a whole is necessary for the RTO/ISO to efficiently dispatch the aggregation, telemetry data for each individual resource in the aggregation may not be.

151. While we are not proposing to prescribe specific metering and telemetry systems for distributed energy resource aggregators, we propose to require each RTO/ISO to revise its tariff to identify any necessary metering and telemetry hardware and software requirements for distributed energy resource aggregators and the individual resources in a distributed energy resource aggregation. These requirements must ensure that the distributed energy resource aggregator will be able to provide the necessary information and data to the RTO/ISO discussed in Section III.B.4.d but also not impose unnecessarily burdensome costs on the distributed energy resource aggregators and individual resources in a distributed energy resource aggregation that may create a barrier to their participation in the organized wholesale electric markets. We also note that there may be different types of resources in these aggregations, some in front of the meter, some behind the meter with the ability to inject energy back to the grid, and some behind the meter without the ability to inject energy to the grid. We therefore seek comment on whether the RTOs/ISOs need to establish metering and telemetry hardware and software requirements for each of the different types of distributed energy resources that

participate in the organized wholesale electric markets through distributed energy resource aggregations, as well as whether we should establish specific metering and telemetry system requirements and, if so, what requirements would be appropriate.

152. With respect to telemetry, we believe that the distributed energy resource aggregator should be able to provide to the RTO/ISO the real-time capability of its resource in a manner similar to the requirements for generators, so the RTO/ISO knows the operating level of the resource and how much that resource can ramp up or ramp down over its full range of capability, including its charging capability for distributed energy resource aggregations that include electric storage resources. These telemetry system requirements may also need to be in place at different locations for geographically dispersed distributed energy resource aggregations that have to provide distribution factors or other similar factors, as discussed above. With respect to metering, we recognize that distributed energy resources may be subject to metering system requirements established by the distribution utility or local regulatory authority. Therefore, we propose that each RTO/ISO should rely on meter data obtained through compliance with these distribution utility or local regulatory authority metering system requirements whenever possible for settlement and auditing purposes, only applying additional metering system requirements for distributed energy resource aggregations when this data is insufficient.

g. Coordination between the RTO/ISO, the Distributed Energy Resource Aggregator, and the Distribution Utility

153. The market rules that each RTO/ISO adopts to facilitate the participation of distributed energy resource aggregations must address coordination between the RTO/ISO, the distributed energy resource aggregator, and the distribution utility to ensure that the participation of these resources in the organized wholesale electric markets does not present reliability or safety concerns for the distribution or transmission system. Thus, we propose to require each RTO/ISO to revise its tariff to provide for coordination among the RTO/ISO, a distributed energy resource aggregator, and the relevant distribution utilities with respect to (1) the registration of new distributed energy resource aggregations and (2) ongoing coordination, including operational coordination, between the RTO/ISO, a distributed energy resource aggregator, and the relevant distribution utility or utilities. We seek comment on the detailed proposals described below.

154. First, we propose that each RTO/ISO revise its tariff to provide for coordination among itself, a distributed energy resource aggregator, and the relevant distribution utility or utilities when a distributed energy resource aggregator registers a new distributed energy resource aggregation or modifies an existing distributed energy resource aggregation to include new resources. The purpose of this coordination would be to ensure that all of the individual resources in the distributed energy resource aggregation are technically capable of providing services to the RTO/ISO through the aggregator and

are eligible to be part of the aggregation (i.e., are not participating in another retail or wholesale compensation program, as discussed in Section III.B.4.a above). In addition, we propose that this coordination provide the relevant distribution utility or utilities with the opportunity to review the list of individual resources that are located on their distribution system that enroll in a distributed energy resource aggregation before those resources may participate in the organized wholesale electric markets through the aggregation. The opportunity for the relevant distribution utility or utilities to review the list of these resources would allow them to assess whether the resources would be able to respond to RTO/ISO dispatch instructions without posing any significant risk to the distribution system and to ensure these resources are not participating in any other retail compensation programs. Finally, we propose that this coordination provide the relevant distribution utility or utilities the opportunity to report such information to the RTO/ISO for its consideration prior to the RTO/ISO allowing the new or modified distributed energy resource aggregation to participate in the organized wholesale electric market. We seek comment on whether the RTO/ISO tariffs should provide for any additional review by or coordination with other parties prior to a new or existing distributed energy resource aggregation participating in the organized wholesale electric markets.

155. Second, we acknowledge that ongoing coordination between the RTO/ISO, a distributed energy resource aggregator, and the relevant distribution utility or utilities may be necessary to ensure that the distributed energy resource aggregator is disaggregating dispatch signals from the RTO/ISO and dispatching individual resources

in a distributed energy resource aggregation consistent with the limitations of the distribution system. Thus, we propose that each RTO/ISO revise its tariff to establish a process for ongoing coordination, including operational coordination, among itself, the distributed energy resource aggregator, and the distribution utility to maximize the availability of the distributed energy resource aggregation consistent with the safe and reliable operation of the distribution system. To account for the possibility that distribution facilities may be out of service and impair the operation of certain individual resources in a distributed energy resource aggregation, we also propose to require each RTO/ISO to revise its tariff to require the distributed energy resource aggregator to report to the RTO/ISO any changes to its offered quantity and related distribution factors that result from distribution line faults or outages. We seek comment on the level of detail necessary in the RTO/ISO tariffs to establish a framework for ongoing coordination between the RTO/ISO, a distributed energy resource aggregator, and the relevant distribution utility or utilities. We also seek comment on any related reliability, safety, and operational concerns and how they may be effectively addressed.

156. Further, we seek comment on the appropriate lines of communication to require. While it may be commercially efficient for the distributed energy resource aggregator to have the burden of communicating with both the RTO/ISO and the distribution utility, and acknowledging the assumption that the distributed energy resource aggregator will be the single point of contact with the RTO/ISO, are there reasons (e.g., distribution operations or a distributed energy resource aggregator's commercial interest) why this

would be insufficient communication? Does a distribution utility that serves distributed energy resources need real-time direct communication with the RTO/ISO, such as in the form of operating procedures or software-enabled communications, in order to operate its distribution system, or can that communication be organized through the distributed energy resource aggregator? Finally, we welcome comments on how the distributed energy resource aggregator model proposed herein would interact with or complement the distribution system operator (DSO) model being discussed in some states, and whether a DSO model might add value to the distributed energy resource aggregator model in terms of facilitating communication among affected entities?

h. Market Participation Agreements for Distributed Energy Resource Aggregators

157. To ensure that a distributed energy resource aggregator complies with all relevant provisions of the RTO/ISO tariffs, it must execute an agreement with the RTO/ISO that defines its roles and responsibilities and its relationship with the RTO/ISO before it can participate in the organized wholesale electric markets. Since the individual resources in these distributed energy resource aggregations will likely fall under the purview of multiple organizations (e.g., the RTO/ISO, state regulatory commissions, relevant distribution utilities, and local regulatory authorities), these agreements must also require that the distributed energy resource aggregator attests that its distributed energy resource aggregation is compliant with the tariffs and operating procedures of the distribution

utilities and the rules and regulations of any other relevant regulatory authority.²³⁸ We therefore propose that each RTO/ISO revise its tariff to include a market participation agreement for distributed energy resource aggregators. We do not propose specific requirements for such agreements at this time, but instead seek comment on the information these agreements should contain.

158. While these agreements will define the roles and responsibilities of the distributed energy resource aggregator, they should not limit the business models under which distributed energy resource aggregators can operate. Therefore, we propose that the market participation agreement for distributed energy resource aggregators that each RTO/ISO must include in its tariff does not restrict the business models that distributed energy resource aggregators may adopt. For example, while the third-party aggregator is a common business model, the market participation agreement for distributed energy resource aggregators should not preclude distribution utilities, cooperatives, or municipalities from aggregating distributed energy resources on their systems or even microgrids from participating in the organized wholesale electric markets as a distributed energy resource aggregation.

²³⁸ This may include any laws or regulations of the relevant retail regulatory authority that do not permit demand response resources to participate in the RTO/ISO markets as the Commission considered in Order No. 719. *See* Order No. 719, FERC Stats. & Regs. ¶ 31,281 at P 154.

IV. Compliance

159. We propose to require each RTO/ISO to submit a compliance filing to demonstrate that it satisfies the proposed requirements set forth in the Final Rule within six months of the date the Final Rule in this proceeding is published in the Federal Register. While we believe that six months is sufficient for each RTO/ISO to develop and submit its compliance filing, we recognize that implementation of the reforms proposed herein could take more time due to the changes that may be necessary to each RTO's/ISO's modeling and dispatch software. Therefore, we propose to allow twelve months from the date of the compliance filing for implementation of the proposed reforms to become effective.

160. We seek comment on the proposed deadline for each RTO/ISO to submit its compliance filing, as well as the proposed deadline for each RTO's/ISO's implementation of the proposed reforms to become effective. Specifically, we seek comment on whether the proposed compliance and implementation timeline would allow sufficient time for each RTO/ISO to implement changes to its technological systems and business processes in response to a Final Rule. We also seek comment on whether the RTOs/ISOs will require more or less time to implement certain reforms versus others.

161. To the extent that any RTO/ISO believes that it already complies with any of the requirements adopted in a Final Rule in this proceeding, the RTO/ISO would be required to demonstrate how it complies in the filing due within six months of the date any

Final Rule in this proceeding is published in the Federal Register. The proposed implementation deadline would apply only to the extent that an RTO/ISO does not already comply with the reforms proposed in this NOPR.

V. Information Collection Statement

162. The Paperwork Reduction Act (PRA)²³⁹ requires each federal agency to seek and obtain Office of Management and Budget (OMB) approval before undertaking a collection of information directed to ten or more persons or contained in a rule of general applicability. OMB's regulations,²⁴⁰ in turn, require approval of certain information collection requirements imposed by agency rules. Upon approval of a collection(s) of information, OMB will assign an OMB control number and an expiration date.

Respondents subject to the filing requirements of a rule will not be penalized for failing to respond to these collection(s) of information unless the collection(s) of information display a valid OMB control number.

163. In this NOPR, we are proposing to amend the Commission's regulations under Part 35 to require each RTO/ISO to propose revisions to its tariff to (1) establish a participation model consisting of market rules that, recognizing the physical and operational characteristics of electric storage resources, accommodates their participation

²³⁹ 44 U.S.C. 3501-3520.

²⁴⁰ 5 CFR 1320 (2016).

in the organized wholesale electric markets and (2) define distributed energy resource aggregators as a type of market participant that can participate in the organized wholesale electric markets under the participation model that best accommodates the physical and operational characteristics of its distributed energy resource aggregation. Accordingly, we encourage comments regarding the time burden expected to be required to comply with the proposed rule regarding the requirement for the RTOs/ISOs to change their tariffs to conform to the proposed rule. Specifically, this NOPR seeks comment on the additional burden and cost (human, hardware, and software) associated with implementation, operation, and maintenance of these new provisions in RTO/ISO tariffs. The Commission will provide estimates for these costs in any future Final Rule, as appropriate.

Burden Estimate and Information Collection Costs: We believe that the burden estimates below are representative of the average burden on respondents. The estimated burden and cost for the requirements contained in this NOPR follow.

FERC-516, as modified by the NOPR in Docket RM16-23-000						
	Number of Respondents	Annual Number of Responses per Respondent	Total Number of Responses	Average Burden (Hours) & Cost Per Response	Total Annual Burden Hours & Total Annual Cost	Cost per Respondent (\$)
	(1)	(2)	(1)×(2)=(3)	(4)	(3)×(4)=(5)	(5)÷(1)
<u>One-Time Tariff Filings (Year 1)</u>	6 ²⁴¹	1	6	1,040 hrs; \$76,960 ²⁴²	6,240 hrs; \$461,760	\$76,960

Title: FERC-516, Electric Rate Schedules and Tariff Filings.

Action: Proposed revisions to an information collection.

²⁴¹ Respondent entities are either RTOs or ISOs.

²⁴² The estimated hourly cost (salary plus benefits) provided in this section is based on the salary figures for May 2015 posted by the Bureau of Labor Statistics for the Utilities sector (http://www.bls.gov/oes/current/naics2_22.htm#13-0000) and scaled to reflect benefits using the relative importance of employer costs in employee compensation from June 2016 (<http://www.bls.gov/news.release/ecec.nr0.htm>). The hourly estimates for salary plus benefits are:

- Legal (code 23-0000), \$128.94
- Computer and mathematical (code 15-0000), \$60.54
- Information systems manager (code 11-3021), \$91.63
- IT security analyst (code 15-1122), \$63.55
- Auditing and accounting (code 13-2011), \$53.78
- Information and record clerk (code 43-4199), \$37.69
- Electrical Engineer (code 17-2071), \$64.20
- Economist (code 19-3011), \$74.43
- Management (code 11-0000), \$88.94

The average hourly cost (salary plus benefits), weighting all of these skill sets evenly, is \$73.74. The Commission rounds it to \$74 per hour.

OMB Control No.: 1902-0096.

Respondents for this Rulemaking: RTOs and ISOs.

Frequency of Information: One-time during Year One.

Necessity of Information: The Commission implements this rule to eliminate barriers to electric storage resource participation in the organized wholesale electric markets and allow for participation of aggregated distributed energy resources in the organized wholesale electric markets.

Internal Review: The Commission has reviewed the changes and has determined that such changes are necessary. These requirements conform to the Commission's need for efficient information collection, communication, and management within the energy industry. The Commission has specific, objective support for the burden estimates associated with the information collection requirements.

Interested persons may obtain information on the reporting requirements by contacting the following: Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC 20426 [Attention: Ellen Brown, Office of the Executive Director]
E-mail: DataClearance@ferc.gov Phone: (202) 502-8663; fax: (202) 273-0873.

Comments concerning the collection of information and the associated burden estimate(s) may also be sent to: Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street, NW, Washington, DC 20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission].

Due to security concerns, comments should be sent electronically to the following e-mail address: oir_submission@omb.eop.gov. Comments submitted to OMB should refer to FERC-516 and OMB Control No. 1902-0096.

VI. Regulatory Flexibility Act Certification

164. The Regulatory Flexibility Act of 1980 (RFA)²⁴³ generally requires a description and analysis of proposed rules that will have significant economic impact on a substantial number of small entities. The RFA mandates consideration of regulatory alternatives that accomplish the stated objectives of a rule and that minimize any significant economic impact on a substantial number of small entities. The Small Business Administration's (SBA) Office of Size Standards develops the numerical definition of a small business.²⁴⁴ These standards are provided on the SBA website.²⁴⁵

²⁴³ 5 U.S.C. 601-12.

²⁴⁴ 13 CFR 121.101.

²⁴⁵ U. S. Small Business Administration, *Table of Small Business Size Standards Matched to North American Industry Classification System Codes* (effective Feb. 26, 2016), https://www.sba.gov/sites/default/files/files/Size_Standards_Table.pdf.

165. The SBA classifies an entity as an electric utility if it is primarily engaged in the transmission, generation and/or distribution of electric energy for sale. Under this definition, the six RTOs/ISOs are considered electric utilities, specifically focused on electric bulk power and control. The size criterion for a small electric utility is 500 or fewer employees.²⁴⁶ Since every RTO/ISO has more than 500 employees, none are considered small entities.

166. Furthermore, because of their pivotal roles in wholesale electric power markets in their regions, none of the RTOs/ISOs meet the last criterion of the two-part RFA definition of a small entity: “not dominant in its field of operation.”²⁴⁷ As a result, we certify that the reforms required by this NOPR would not have a significant economic impact on a substantial number of small entities.

VII. Environmental Analysis

167. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect

²⁴⁶ 13 CFR 121.201 (Sector 22, Utilities).

²⁴⁷ The RFA definition of “small entity” refers to the definition provided in the Small Business Act, which defines a “small business concern” as a business that is independently owned and operated and that is not dominant in its field of operation. The Small Business Administration’s regulations at 13 CFR 121.201 define the threshold for a small Electric Bulk Power Transmission and Control entity (NAICS code 221121) to be 500 employees. See 5 U.S.C. 601(3) (citing to section 3 of the Small Business Act, 15 U.S.C. 632).

on the human environment.²⁴⁸ We conclude that neither an Environmental Assessment nor an Environmental Impact Statement is required for this NOPR under section 380.4(a)(15) of the Commission's regulations, which provides a categorical exemption for approval of actions under sections 205 and 206 of the FPA relating to the filing of schedules containing all rates and charges for the transmission or sale of electric energy subject to the Commission's jurisdiction, plus the classification, practices, contracts and regulations that affect rates, charges, classifications, and services.²⁴⁹

VIII. Comment Procedures

168. The Commission invites interested persons to submit comments on all matters and issues proposed in this Proposal to be adopted, including any related matters or alternative proposals that commenters may wish to discuss. Comments are due **[60 days after publication in the FEDERAL REGISTER]**. Comments must refer to Docket No. RM16-23-000 and must include the commenter's name, the organization they represent, if applicable, and their address.

169. The Commission encourages comments to be filed electronically via the eFiling link on the Commission's web site at <http://www.ferc.gov>. The Commission accepts

²⁴⁸ *Regulations Implementing the National Environmental Policy Act of 1969*, Order No. 486, 52 Fed. Reg. 47,897 (Dec. 17, 1987), FERC Stats. & Regs., ¶ 30,783 (1987).

²⁴⁹ 18 CFR 380.4(a)(15).

most standard word processing formats. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format. Commenters filing electronically do not need to make a paper filing.

Commenters that are not able to file comments electronically must send an original of their comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street, NE, Washington, DC 20426.

170. All comments will be placed in the Commission's public files and may be viewed, printed, or downloaded remotely as described in the Document Availability section below. Commenters on this Proposal are not required to serve copies of their comments on other commenters.

IX. Document Availability

171. In addition to publishing the full text of this document in the Federal Register, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through the Commission's Home Page (<http://www.ferc.gov>) and in the Commission's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, NE, Room 2A, Washington, DC 20426.

172. From the Commission's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and

Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number of this document, excluding the last three digits, in the docket number field.

173. User assistance is available for eLibrary and the Commission's website during normal business hours from the Commission's Online Support at (202) 502-6652 (toll free at 1-866-208-3676) or email at ferconlinesupport@ferc.gov, or the Public Reference Room at (202) 502-8371, TTY (202) 502-8659. E-mail the Public Reference Room at public.referenceroom@ferc.gov.

List of subjects in 18 CFR Part 35:
Electric power rates
Electric utilities

By direction of the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

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In consideration of the foregoing, the Commission proposes to amend Part 35 Chapter 1, Title 18 of the *Code of Federal Regulations* as follows:

PART 35 – FILING OF RATE SCHEDULES AND TARIFFS

Amend § 35.28(b) as follows, by adding new paragraphs (9) through (12).

§ 35.28 (b) Definitions

(9) *Electric storage resource* as used in this section means a resource capable of receiving electric energy from the grid and storing it for later injection of electricity back to the grid regardless of where the resource is located on the electrical system.

(10) *Distributed energy resource* as used in this section means a source or sink of power that is located on the distribution system, any subsystem thereof, or behind a customer meter.

(11) *Distributed energy resource aggregator* as used in this section means the entity that aggregates one or more distributed energy resources for purposes of participation in the capacity, energy and ancillary service markets of the regional transmission organizations and independent system operators.

(12) *Organized wholesale electric markets* as used in this section means the capacity, energy, and ancillary service markets operated by regional transmission organizations and independent system operators.

Amend § 35.28(g) as follows, by adding new paragraph (9)(i)(A-L).

§ 35.28

(g) Tariffs and operations of the Commission-approved independent system operators and regional transmission organizations.

(9) Electric Storage Resources.

(i) Each Commission-approved independent system operator and regional transmission organization must have tariff provisions providing a participation model for electric storage resources that

- a. Ensures that electric storage resources are eligible to provide all capacity, energy and ancillary services that they are technically capable of providing in the organized wholesale electric markets;
- b. Incorporates bidding parameters that reflect and account for the physical and operational characteristics of electric storage resources;
- c. Ensures that electric storage resources can be dispatched and can set the wholesale market clearing price as both a wholesale seller and wholesale buyer consistent with existing rules that govern when a resource can set the wholesale price;
- d. Establishes a minimum size requirement for participation in the organized wholesale electric markets that does not exceed 100 kW; and
- e. Specifies that the sale of energy from the organized wholesale electric markets to an electric storage resource that the resource then resells back to those markets must be at the wholesale locational marginal price.

Amend § 35.28(g) as follows, by adding new paragraph (g)(10)(i)(A-I).

§ 35.28

(g) Tariffs and operations of the Commission-approved independent system operators and regional transmission organizations.

(10) Distributed Energy Resource Aggregators.

(i) Each independent system operator and regional transmission organization must have tariff provisions that allow distributed energy resource aggregations to participate directly in the organized wholesale electric markets. Each regional transmission organization and independent system operator must establish distributed energy resource aggregators as a type of market participant and must allow the distributed energy resource aggregators to register distributed energy resource aggregations under the participation model in the regional transmission operator or the independent system operator's tariff that best accommodates the physical and operational characteristics of the distributed energy resource aggregation.

(ii) Each regional transmission operator and independent system operator, to accommodate the participation of distributed energy resource aggregations, must establish market rules on:

- a. Eligibility to participate in the organized wholesale electric markets through a distributed energy resource aggregation;
- b. Locational requirements for distributed energy resource aggregations;
- c. Distribution factors and bidding parameters for distributed energy resource aggregations;
- d. Information and data requirements for distributed energy resource aggregations;
- e. Modification to the list of resources in a distributed energy resource aggregation;
- f. Metering and telemetry system requirements for distributed energy resource aggregations;
- g. Coordination between the regional transmission organization or independent system operator, the distributed energy resource aggregator, and the distribution utility;
- h. Market participation agreements for distributed energy resource aggregators.

Appendix A: Abbreviated Names of Commenters

The following table contains the abbreviated names of the commenters that are used in this Notice of Proposed Rulemaking.

Abbreviation	Commenters
Advanced Energy Economy	Advanced Energy Economy
AEP	American Electric Power Service Corporation
AES Companies	Indianapolis Power & Light Company, The Dayton Power and Light Company, AES Energy Storage LLC, AES ES Tait LLC and all other AES U.S. operating companies that own generation and storage
Alevo	Alevo Analytics
Advanced Microgrid Solutions	Advanced Microgrid Solutions, Inc.
APPA	American Public Power Association
Advanced Rail Energy Storage	Advanced Rail Energy Storage, LLC
Brookfield Renewable	Brookfield Renewable
California Department of Water Resources	California Department of Water Resources
California Energy Storage Alliance	California Energy Storage Alliance
Delaware Commission	Delaware Public Service Commission
Duke Energy	Duke Energy Corporation
EEI	Edison Electric Institute
Enel Green Power	Enel Green Power North America, Inc.
Electric Power Supply Association	Electric Power Supply Association
Electric Vehicle R&D Group	University of Delaware Electric Vehicle R&D Group
Energy Storage Association	Energy Storage Association
FirstLight	FirstLight Power Resources Management LLC
Golden Spread	Golden Spread Electric Cooperative, Inc.
Ice Energy	Ice Energy
Independent Energy Producers Association	Independent Energy Producers Association
Manitoba Hydro	Manitoba Hydro
Minnesota Energy Storage Alliance	Minnesota Energy Storage Alliance
National Electrical Manufacturers Association	National Electrical Manufacturers Association
National Hydropower Association	National Hydropower Association

Abbreviation	Commenters
New York Battery and Energy Storage Consortium	New York Battery and Energy Storage Technology Consortium
NextEra	NextEra Energy Resources, LLC
NRECA	National Rural Electric Cooperative Association
NY Transmission Owners	Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York Power Authority, New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation, Orange and Rockland Utilities, Inc., Power Supply Long Island, and Rochester Gas and Electric Corporation
Ormat	Ormat Nevada Inc.
Pacific Gas & Electric	Pacific Gas and Electric Company
Public Interest Organizations	Sustainable FERC Project on behalf of Natural Resources Defense Council and Union of Concerned Scientists
PJM Market Monitor	Independent Market Monitor For PJM
Quanta	Ralph Masiello, Quanta Technologies, LLC
RES Americas	Renewable Energy Systems Americas Inc.
SoCal Edison	Southern California Edison Company
Schulte Associates	Schulte Associates LLC
Solar Grid Storage	Solar Grid Storage, LLC
SolarCity	SolarCity Corporation
Steffes	Steffes
Tesla	Tesla Motors, Inc.
Viridity	Viridity Energy, Inc.
Wellhead	Wellhead Electric Company
Xcel Energy Services	Xcel Energy Services, Inc., on behalf of its operating company affiliates, Northern States Power and Southwestern Public Service Company

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