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Advanced Energy Industries, Inc. SEGIS Developments

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Abstract

The Solar Energy Grid Integration Systems (SEGIS) initiative is a three-year, three-stage project that includes conceptual design and market analysis (Stage 1), prototype development/testing (Stage 2), and commercialization (Stage 3). Projects focus on system development of solar technologies, expansion of intelligent renewable energy applications, and connecting large-scale photovoltaic (PV) installations into the electric grid. As documented in this report, Advanced Energy Industries, Inc. (AE), its partners, and Sandia National Laboratories (SNL) successfully collaborated to complete the final stage of the SEGIS initiative, which has guided new technology development and development of methodologies for unification of PV and smart-grid technologies. The combined team met all deliverables throughout the three-year program and commercialized a broad set of the developed technologies.

Acknowledgments

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Nomenclature

AC	Alternating Current (as related to cyclic power/current/voltage)
AE	Advanced Energy Industries, Inc.
AMI	Automated Meter Infrastructure (remote meter reading and limited Smart Grid functions)
API	Application Programming Interface
a-Si	Amorphous Silicon (not crystalline PV module technology)
BDEW	Bundesverband dert Energie (German Association of Energy and Water Industries)
BEMS	Building Energy Management System
BOS	Balance-of-System (everything but the PV modules in a PV system)
CC	Correlation Coefficient
CALISO	California ISO
CCB	Correlation Coefficient-Based (referring to Pearson's or Spearman's correlation of two entities)
CdTe	cadmium telluride
CEC	California Energy Commission
CIGS	Copper Indium Gallium Diselenide (PV module technology)
CIMSS	Cooperative Institute for Meteorological Satellite Studies
CPV	Concentrating Photovoltaics
c-Si	Crystalline Silicon (as related to PV module technology)
DC	Direct Current (not cyclic Power, current or voltage)
DOE	U.S. Department of Energy
DSP	Digital Signal Processor
EPRI	Electric Power Research Institute
EMS	Energy Management System
FF	Fill Factor (typically the ratio of maximum power from a PV technology to the product of the open circuit voltage and short circuit current)
FTP	File Transfer Protocol
GOES	Geostationary Operational Environmental Satellite
GPS	Global Positioning System
CRAS	CIMSS Regional Assimilation System
HVAC	Heating, Ventilation, and Air Conditioning
IEEE	Institute of Electrical and Electronics Engineers
IP	Internet Protocol
kVA	kilo-Volt-Amperes (a measure of real plus imaginary power)
kVAr	kilo- Volt-Ampere reactive
kW	kilo-Watt (a measure of instantaneous power)
KWh	kilo-Watt hour (a measure of energy)
LCOE	Levelized Cost of Energy
LVRT	Low Voltage Ride Through (continuing to supply PV energy with low utility voltage)
MATLAB	Matrix Laboratory (a numerical computing environment)
MIT	Massachusetts Institute of Technology
MPP	Maximum Power Point
MPPT	Maximum Power Point Tracking

MVA	Megavolt Ampere
NEC	National Electrical Code (used for installation requirements in the USA)
NIE	Network Integration Engine
NIST	National Institute of Standards and Technology
NPPT	Northern Plains Power Technologies
ODOT	Oregon Department of Transportation
P&O	Perturb-and-Observe
PCBA	Printed Circuit Board Assembly
PEPCO	Potomac Electric Power Company
PF (or pf)	Power Factor
PGE	Portland General Electric
PLC	Power Line Carrier (communication method)
PMU	Phasor Measurement Unit
PV	Photovoltaic
PVSC	Photovoltaic Specialist Conference sponsored by IEEE
RAM	Random Access Memory
RCA	Rate Corrected Algorithm
RPS	Renewable Portfolio Standard
REC	Renewable Energy Certificate (or Credit)
RMS	Root-Mean-Square as applied to AC voltage or current
SCADA	Supervisory Control and Data Acquisition
SEGIS	Solar Energy Grid Integration System (project to develop advanced PV system technologies)
SEL	Schweitzer Engineering Laboratories, Inc.
SFS	Sandia Frequency Shift (widely used method used for island detection in distributed generators with positive feedback)
SNL	Sandia National Laboratories
SPF	Static Power Factor
STC	Standard Test Conditions
SVS	Sandia Voltage Shift (widely used method used for island detection in distributed generators with positive feedback)
TCP	Transmission Control Protocol
UARTS	Universal Asynchronous Receiver/Transmitter
UL	Underwriters Laboratories, Inc.
VAr	Volt-Ampere reactive
WAN	Wide Area Network

Executive Summary

Initiated in 2008, the Solar Energy Grid Integration System (SEGIS) initiative is a partnership that includes the U.S. Department of Energy (DOE), Sandia National Laboratories (SNL), U.S. industry, electrical utilities, and universities. Its focus is on the development of technologies required to facilitate the integration of high-penetration connections and large-scale photovoltaic (PV) power generation into the nation's grid. The SEGIS program is a three-year, three-stage initiative that includes conceptual design and market analysis in Stage 1, prototype development and testing in Stage 2, and movement toward commercialization or actual commercialization in Stage 3. Advanced Energy Industries, Inc. (AE) and its SEGIS team consisting of Portland General Electric (PGE), Schweitzer Engineering Laboratories, Inc. (SEL), Northern Plains Power Technologies (NPPT), and SNL, have successfully collaborated to complete the work under the third and final stage of the SEGIS initiative.

The goal of the SEGIS initiative is to remove barriers to large-scale general integration of PV and to enhance the value proposition of PV energy by enabling PV to act as much as possible as if it were equivalent to a conventional utility power plant. It is immediately apparent that the advanced inverters and controllers go beyond looking like conventional power plants, making high penetrations of PV not just acceptable, but desirable to interconnected utilities. That said, PV power generating plants will not achieve their full potential until utilities cease to regard them as a problem or potential hazard, but instead as a resource that can be monitored and dispatched to contribute to the overall efficiency and stability of the electrical grid.

Executive summaries of each of the specific SEGIS tasks addressed by AE are detailed as follows to provide a high-level overview of what is included in this report.

Task 1: Maximum Power Point Tracking (MPPT)

The goals of this task are two-fold, with both targeted to lower the cost of energy for installed PV. Firstly, the team created a metric for comparing dynamic efficiencies of Maximum Power Point Tracking (MPPT) algorithms and has now proposed that metric as a starting point (protocol) for an industry accepted standard test plan. The proposed test protocol weighs all static and dynamic PV conditions equally, leveraging observed changes in irradiance from across the U.S. to help define the slow and fast ramp functions used in the testing protocol. The developed testing protocol has been presented at the 2011 Institute of Electrical and Electronics Engineers (IEEE) Photovoltaic Specialist Conference (PVSC) in Seattle, Washington. It was generally well received by the participants. The second goal of this task refines and tunes the developed Rate Corrected MPPT Algorithm (RCA) to verify that specific tuning parameters can be adjusted for gains in total energy harvest with most commercially available PV module families (CdTe, CIGS, CPV, c-Si, a-Si, 2-j Si, 3-j Si). The team set out to show that specific module operating characteristics could lead to increased energy harvest if the MPPT algorithm was tuned to react to the module's characteristics and behaviors. The team commercialized this MPPT algorithm during the SEGIS program and is now manufacturing AE products using the developed algorithms.

Task 2: Building EMS Solar Energy System Integration

The purpose of this task was to establish a common means of communication between the SEGIS-enabled PV energy system and commercially available building energy management systems (BEMSs). One of today's challenges with PV installations is the monitoring of system performance, leveraging standalone systems and using redundancy without adding significant cost to the installation. While required in certain markets for incentives and rebate programs, this redundancy does not add additional value to the facility served by the PV energy system. By integrating the PV energy system data stream into the facility building control system, reductions in total cost of installation can be realized, allowing building engineers and maintenance teams to have greater insight into the status and performance of their buildings while providing more advanced control of the building electrical infrastructure using the solar plant as a control point. There exists a number of communications protocols used within the building industry today. The AE-led SEGIS team attempted to provide a lowest cost solution while adding value by identifying a common protocol that integrates with any of the BEMSs available on the market today. The developed technology has been commercialized and is available for use today.

Task 3: Intelligent String Combiner

The purpose of the String Level Monitoring and Control task was to develop a unique and higher value approach to the PV string-level monitoring and controls. Most current industry devices are simply string-level current monitors. They do not address a key problem: detecting, and ideally isolating, ground faults in the PV array. Current industry devices are also difficult to install and commission. These challenges have been the primary barrier to widespread adoption of a “smart” string combiner solution. The AE-led SEGIS team developed a prototype functional string combiner that specifically addresses these aforementioned problems. The prototype combiner is a 16-string combiner with string-level ground fault current and string current monitoring and disconnect at the combiner level (positive and negative disconnect). The combiner design also attempted to solve a common commissioning issue (from the installer’s perspective, it is a combiner box) by eliminating costly power and communications cabling runs to each combiner. The developed technology was carried through to the prototype stage where the team demonstrated its value proposition to the review team. Further advances in the technology, as well as standards revisions, should allow this prototype to become market ready in the near future.

Task 4: Irradiance Forecasting

In this task, the team proposed two sets of irradiance prediction tools. The first, called a “nearcast” tool, would produce irradiance predictions in a six-hour-ahead window and data suitable for use in utility planning and marketing processes. The other tool, called a “nowcast”, was more exploratory. The focus of this approach was using a much higher-resolution tool that would deliver irradiance predictions in a ten-minute-ahead window with data suitable for use by a solar power plant controller, system operator, or utility. In this report, progress on these tools is described, illustrative data are shown, and the reasons why the AE-led team did not reach a commercialized end product are discussed.

Task 5: Utility Control Functionality

The primary goal of this task was to develop and commercialize inverter-specific controls that would benefit broader electrical system operation under high PV penetration environments. Power factor (PF) control, curtailment of output power, and ramp-rate limiting were some of the commercialized features associated with this task. In addition to allowing for these operational controlling features, an internal scheduler was developed to enable standalone control in the absence of a plant controller or Supervisory Control and Data Acquisition (SCADA) system. Schedules for PF control, curtailment, and ramp rate can be programmed internally to the inverter system, allowing for autonomous or scheduled control. Field testing, lab testing, and demonstrations of the developed technology are detailed in the body of this report.

Task 6: Synchrophasor-based Island Detection

In this task, the team set out to prove island detection could be accomplished using synchrophasor reference signals from across the distribution network. The use of time-synchronized remote and local voltage, current, and frequency information enables island-detection logic to be implemented, as well as true distributed generation feature sets to be developed. Demonstrations of the developed island-detection technique, in addition to modeling validation and lab testing, are covered in the body of this document. Islanding cases involving multiple inverters, synchronous generators, and large-load switching events are analyzed and presented to show the robustness of the developed technology. The utility inverter features discussed herein, coupled with the synchrophasor data, show foundational blocks for a true distributed generation resource capable of performing "grid healing" functionality throughout the distribution feeders of today's electrical grid. This technology is still in the development stage at the conclusion of the SEGIS program, and although demonstrations have been completed showing the effectiveness of the developed technology, work remains to ensure 100% detection across the distribution network under all scenarios.

Task 7: System Integration

This final task was added at the conclusion of Stage 1 of the program when the team realized that a critical component had been overlooked – total system integration of the new functionalities. The System Integration task was broken into two parts: 1) System Controller and 2) SEGIS Database. These integral components tie the aforementioned tasks into a single cohesive system and enable integration into various field applications.

System or Secondary Controller

> The system secondary controller was designed, prototyped, and built as a necessary component to tie together the tasks associated with the SEGIS developments. The system secondary controller interfaces with the inverter control logic (primary controller) to provide the MPPT tuning parameters, utility scheduling functionality, synchrophasor measurement interfaces, as well as to push the balance-of-system (BOS) and inverter data up to the developed database and other third parties. The system controller was a necessary development to allow for integrating the SEGIS technologies into existing, as well as future, inverters without burdening the safety-critical control contained in the primary system Digital Signal Processor (DSP). The system secondary controller is the "glue" of the developed SEGIS technologies, and has been designed and developed to represent a platform from which additional and future technologies can easily integrate into the PV system. The secondary controller specifics are highlighted in the body of this document.

SEGIS Database and API

> The purpose of SEGIS Database and Applications Programming Interface (API) are to provide a highly flexible repository to store data generated by new components developed under SEGIS, and to provide a method to extract data from the database. The data stored in the database provide substantial analytic and metric value to AE internal and external customers and to the industry as a whole. Data are used to improve design

cycle time, enabling delivery of reliable utility-scale SEGIS technology-equipped inverter systems. Data are further used by customers and partners providing critical information to the myriad of stakeholders in a solar power plant. A prototype database system and API was developed throughout the three-year SEGIS program. The database stores inverter, smart-string combiner, and weather station data, and provides visibility into system operation, history of events, availability, and uptime. Detailed data from configured systems are shown in the main body of this report.

1 Introduction

1.1 High Penetration Environment

The program tasks selected by Advanced Energy Industries, Inc. (AE) and its partners for the duration of the Solar Energy Grid Integration System (SEGIS) program are intended as solutions for the future of grid-tied photovoltaic (PV) installations. As such, high penetration PV environments spread throughout different distribution feeder configurations were essential design elements in the forming of the program tasks and goals. The tasks described herein are intentionally interrelated to provide a platform that scales from dispersed PV to very high penetration environments. At the onset of the SEGIS program, many of today's distribution interconnection issues were thought to be many years removed, or in some instances non-issues. The foresight of the extended teams' plans to solve complex interconnection challenges related to the electrical distribution system has resulted in commercially available technologies at a time when they are needed.

1.2 Levelized Cost of Energy (LCOE)

A second noteworthy framework used by the AE-led SEGIS program team is the concept of Levelized Cost of Energy (LCOE). Program goals, design decisions, and ultimately commercially available end products were developed leveraging the notion of a system that attempts to drive increased functionality to the inverter and balance-of-system (BOS) components while reducing or minimizing costs. Specific items focused on LCOE under this SEGIS program include: the development of an industry standard Maximum Power Point Tracking (MPPT) testing protocol, improvements in energy harvest techniques, design for long term reliability, and Volt-Ampere reactive (VAr) and power factor (PF)control implemented at the inverter level.

1.3 Team Approach to Solving Industry Challenges

Advanced Energy recognized that deep partnering with relevant experts would be necessary to successfully develop technologies that could accelerate adoption of distributed PV. Each partner selected contributed not only in the conceptual stage of the program, but additionally in the scope, detailed design, and demonstration stages of the SEGIS three-year development program. The AE-led team is comprised of the following partners:

> Schweitzer Engineering Laboratories, Inc. (SEL)
> SEL is a recognized leader in protection and control systems for both the transmission and sub-transmission layers of the electrical grid. SEL is also well known as an industry leader in leveraging synchrophasors for control and protection of critical system infrastructure. (One of the SEGIS applications is summarized in the video at **https://www.selinc.com/synchrophasors/**)

> Northern Plains Power Technologies (NPPT)
> NPPT, under the direction of Dr. Michael Ropp, are widely recognized island-detection experts in the PV industry. Further, the NPPT team brings vast experience in system voltage stability studies, advanced electrical system modeling, and a wealth of knowledge of the PV industry and its roots.

> Portland General Electric (PGE)
> Portland General Electric is a progressive Oregon utility that installs, commissions, and

owns PV systems within its service territory. PGE has developed an advanced distributed generation Supervisory Control and Data Acquisition (SCADA) system to manage their generation assets, and have moved to include larger PV installations under this control and data-management solution.

The combined teams focused on addressing interconnection issues associated with high penetration PV, while introducing new technologies to allow for expansion of the PV industry. The technical backgrounds of the interdisciplinary team led to innovative and sensible approaches to the challenges at the core of the SEGIS program goals.

1.4 Platform Integration

The AE-led SEGIS team focused design efforts on creating scalable platforms allowing for future expandability of system features and functions. The team realized that although many of today's interconnection challenges are currently being addressed through SEGIS-developed functionalities, more challenges will emerge in the near future. Accordingly, solutions that are expandable and extensible will produce faster time to market and increased value moving forward, shortening the time gap between future need and future solutions. Considerable effort was taken during the development of the SEGIS functionality to ensure future expandability to interconnection risks that are yet to be identified as concerns. Further, each of the program tasks completed under this body of work is intentionally interrelated. The need for voltage support functionality (PF, VAr) will ultimately drive alternative methods of island detection. The system integration task ties together the design for reliability, LCOE, and communications infrastructure required for communicating with, and ultimately controlling, the inverter and balance of system components.

2 SEGIS Project Overview

2.1 Objectives

The PV Powered team had three primary objectives when it set out to deliver on the SEGIS program:

- Develop new and innovative technologies needed to address the overarching SEGIS objective of reaching grid parity, focusing on energy harvest (LCOE) and grid integration.
- Develop the cross-functional partnerships in the industry required to solve the complex problems that are Smart Grid.
- Bring Research and Development (R&D) funding to a small U.S. startup company that could not afford to invest in the R&D needed to remain competitive while shipping current products.

Since that time, many things have happened – PV Powered was acquired by AE, the SEGIS program went through a funding delay, and the need for grid-friendly inverters has come much sooner than the industry anticipated. Through all this change, AE has developed powerful partnerships that would likely not have been possible without the SEGIS program as a catalyst. This combination has led to both short- and long-term innovations that will help both AE customers and the PV industry for years to come.

2.2 Scope

The AE-led team originally proposed a broad scope of developments, and then narrowed the scope over the course of the three-stage program based on industry needs and value. Generally, the scope can be articulated as a focus on components outside the fundamental power inverter. The next section, Methodology, describes the scope and approach that the team used in this program.

2.3 Methodology

2.3.1 Original Proposal

- <u>Goals</u>: The original proposal contained five separate tasks targeted to address immediate as well as long-term industry gaps regarding PV system performance, system safety, system cost, and long-term system reliability. This multi-task approach is balanced with roughly equal amounts of immediate and long-term industry needs, in addition to focusing design efforts on a breadth of innovative technologies, including balance of system (smart-string combiner), inverter-specific (utility controls), cost of ownership (MPPT, energy management system [EMS] integration), high penetration (Phasor Measurement Unit [PMU]-based islanding), and performance and reliability metrics (database and Application Programming Interface [API]).
- <u>Likelihood of Success</u>: Each separate task outlined above had its own relative measure of market success ranging from very likely (MPPT) to a “long shot” (irradiance forecasting) based on the three-year program timeline as well as the level of maturity of the individual

technologies. The AE-led SEGIS team continually analyzed the maturity of these governing technologies throughout the first stage of the award and modified reviewer expectations and program goals as new information became available.

- Market Goals: For this first stage of the SEGIS program, the market goals were focused on developing technologies that welcomed high-penetration PV environments, while adding value to the overall system to drive down total installation costs. The notion of driving down total system costs expanded beyond the PV system to the electrical distribution system as a whole, allowing for realizations in savings around very expensive voltage regulation equipment including on-load tap changers, switched capacitor banks, and static VAr compensators. Additionally, the BOS components available at the time the proposal was written lacked intelligence and capabilities that could fundamentally lower installation barriers and overall system costs.

- Barriers: There existed a number of barriers to adoption and development of the proposed five tasks at the onset (and closure) of Stage 1 of the SEGIS program. Most notably, standards development began to fall behind industry needs, cost targets for system installations began to rapidly fall, and safety concerns for high-penetration PV began to become prevalent. Additionally, the team chose to develop many different technologies with a capable, yet small team of engineers, and workload and timing became a barrier unto itself.

- Lessons Learned: At the conclusion of Stage 1, the team validated that the five tasks selected could each add tremendous value to the overall industry. However, many initial plans needed modification to become product ready by the closure of the three-year award period. As an example, Automated Meter Infrastructure (AMI) was thought to be capable of handling the synchrophasor-based islanding communication infrastructure needs, and it became increasingly evident by the closure of Stage 1 that this was in fact not the case. Secondly, the utility command and control needs for interconnection acceptance were becoming increasingly needed in certain geographical locations, and as such required a solution that could meet current regulatory standards (IEEE 1547, UL 1741) while providing this functionality. Lastly, cost pressures started to become more prevalent, and the team needed to focus on lowest-cost solutions that still met internal and external reliability targets, as well as functionality goals capable of expanding the system savings throughout a wider system classification.

2.3.2 Stage 2 Proposal

- Goals: The primary goal of the Stage 2 effort was to bring the proposed technologies to a prototype stage where their impacts could be realized in the form of functional demonstrations. To accomplish this goal, it was quickly realized that the team needed to add an additional task to bring all of the proposed technologies together into a system that could be implemented on a single inverter platform. The team added the secondary system controller to fill this need. This secondary controller would communicate with all of the relevant devices (balance of system, PMU, utility interface, database, and inverter Digital Signal Processor [DSP]) to allow for all of the developed technologies to coexist on a single prototype.

- Likelihood of Success: The prototyping period (Stage 2) was a proving ground for technology feasibility; similar to Stage 1, there was a moderate likelihood of individual successes and failures, depending on the associated task. At this point in the program, the team felt very confident in most of the proposed tasks. The weather forecasting task was still thought to be a long shot in terms of becoming a commercializable product within the time span of the three-year SEGIS program.

- Market Goals: The market goals during Stage 2 of the program shifted to encompass more understanding of what each task would be worth to the various inclusive stakeholders. Economic analyses were beginning to take shape to quantify the respective gains associated with improved MPPT performance, the value of the Static Power Factor (SPF) package to end users (reducing demand charges, trading kWhs for kVArs), and the database and secondary controller were showing significant promise toward tracking long-term reliability for the commercial inverter fleet. In addition, customer and utility feedback to the developing feature and function sets helped to drive not only the scope and configurability of controlling points for the extended inverter system, but also the timing needed to commercialize products to solve emerging issues throughout distribution feeders experiencing high penetration of PV through localized clustering.

- Barriers: Stage 2 was not without its own set of barriers. The team uncovered non-detect zones associated with the synchrophasor-based islanding, issues with latency in observed communication channels, and cost challenges with "off-the-shelf" products that exceeded target maximums. Designing, developing, and prototyping a complete secondary controller from scratch, capable of interfacing many devices over different communication channels, also proved to be difficult within the nine-month window. Design tradeoffs were made throughout the Stage 2 award period to accommodate the schedule while not limiting end-use functionality. Lastly, standards re-evaluation began to take place as the IEEE 1547.8 committee began addressing necessary changes to the existing IEEE 1547 to allow for advanced functionality from these devices. The team quickly got involved in the working group to assist in drafting this next version of interconnection requirements.

- Lessons Learned: The team continued throughout the Stage 2 award period to bring all five tasks to the prototype stage (plus the sixth task). It was evident that to succeed in reaching a commercializable set of products prior to the closure of Stage 3, the team would need to focus on the most market-ready programs and cut back developments on the remaining "longer-to-market" tasks. In particular, the irradiance forecasting and "smart-string combiner" tasks still needed additional refinement as well as collaborative efforts from multiple stakeholders to reach a point where they could be considered commercializable. As such, although increasingly important to the industry as a whole, they were removed from the Stage 3 scope of work. Another major lesson learned for the team was a growing need for configuring the end solutions to a host of stakeholders (utilities, building EMS, end users, etc.), and as such, the secondary controller effort became increasingly important to the overall success of the AE-led SEGIS program.

2.3.3 Stage 3 Proposal

- Goals (technical and market driven): The Stage 3 goals were well understood at the onset of the third stage of the SEGIS program. The team needed to drive the selected "market-ready" prototype developments of Stage 2 into commercial products. In parallel, the industry was demanding solutions that would lessen the impacts of high penetrations of

PV throughout respective distribution feeders. This led the team to focus efforts on the utility command and control, MPPT developments, and the secondary system controller to ensure program success. The utility command and controls package commercialization effort included the ability for the inverter to change PF, active power output, ramp rates, and transition times to meet interconnection requirements. To accomplish this, the inverter needed the capability to be remotely controlled (through a SCADA or BEMS) as well as to be standalone with internal scheduling capability. The team set out to commercialize this functionality by the closure of the program. Including the newly developed RCA MPPT algorithm in commercial inverters was a second goal of this Stage 3 effort. The team had documented material gains in energy harvest by leveraging the created algorithm and planned to incorporate it into production units by the closure of the award period. In addition to these market requirements for added system functionality (utility controls package, RCA MPPT algorithm), the team chose to carry forward the synchrophasor-based island detection to continue to drive awareness industry wide for a need to migrate away from intrusive island-detection techniques widely employed today. The end goals were: 1) to have the utility command and control package shipping in commercial inverters, 2) to have the newly developed MPPT algorithm shipping in commercial inverters, and finally 3) to have successfully demonstrated synchrophasor-based islanding detection and mitigation in a multitude of scenarios.

- <u>Success Criteria/Likelihood of Success</u>: Although prototypes had been developed throughout the Stage 2 award period, there remained a large number of unknowns associated with migrating the developed functionalities to commercial product and, ultimately, production. The team was confident that they could develop data-driven solutions to increase the likelihood of success to bring the utility command and controls package into commercial production. Likewise, the team was confident that with testing to date (as well as continual monitoring of performance), the newly created MPPT algorithm would be ready for productization by the conclusion of the Stage 3 award period. However, new ground was being broken on the compliance testing front, as the scheduled PF, scheduled curtailment, and ability to change ramp rates and transition rates for these control parameters were now being allowed to be modified by end customers. Testing strategies needed to be developed to allow for the products to be listed to the current version of UL 1741 as well as IEEE 1547. This remained an unknown as the Stage 3 program was initiated. Lastly, the team knew that there still existed many challenges to the commercialization of the islanding-detection strategy being proposed. Success for this development would be measured by increasing industry awareness and acceptance of the proposed technique with the team assisting in redrafting the relevant standards to allow for inclusion of communications-based island-detection strategies. In summary, the team carried forward with the relevant programs that provided for maximum market value with the highest likelihood of program success.

- <u>Barriers</u>: There existed a number of barriers to commercialization as the Stage 3 award period began. The most prominent ones included: developing and agreeing to testing strategies for certifying the newly developed technologies to existing standards, market direction needs and timing, AE direction and product development schedules (internal plans and commitments to customers), and finally capabilities to incorporate the developed technologies in a cost-effective manner.

- Lessons Learned: At the conclusion of the Stage 3 program, the team successfully met the goals that were set forth for Stage 3. There were many lessons learned throughout the program, and most prominent was the ability to recognize market trends and focus design, development, and commercialization efforts on the specific products that would provide the industry, as well as AE, the most value. The team was very ambitious at the beginning of the SEGIS program. At every stage of the program, the team needed to pare back on the deliverables to account for market direction changes as well as actual capability to deliver within the allotted timeframe. Recognition that not all ideas will become commercial products allowed the team to continue to develop innovative solutions while focusing on market needs throughout the course of the SEGIS award period. Lastly, the team recognized the value of industry partnerships to develop unique, technologically innovative solutions. Partnering with experts ranging from utilities to power-system protection engineers to modeling and system engineers allowed for developed solutions to meet the needs of the industry as a whole.

- Items Trimmed from Stage 3 Efforts: The team recognized that there existed too many prototypes to carry to completion through the Stage 3 award period. Tough decisions were made on which to commercialize by closure of the award period based on market need, risk, technology developments, and commercial value. The tasks that were not carried forward included forecasting (leveraging satellite imagery) and the smart-string combiner. EMS integration was completed in Stage 2. Each of these tasks still hold tremendous market value; however, the team did not feel confident that they could be finished within the award timeframe.

2.4 Concept Paper Topics Selected for the Project

The AE-led SEGIS team leveraged a broad approach at the inception of the SEGIS program. The team understood many of the industry-wide pain points affecting system design and costs and wanted to investigate and understand areas where improvements could greatly benefit the PV industry as a whole. Cost of ownership (LCOE), installation flexibility, functional improvements, integration into existing distribution system, and system safety all drove the topics briefly discussed below.

- MPPT: The U.S. PV industry lacked a manner in which to quantify MPPT performance across manufacturers. In addition, existing methods were static measurements and did not provide any reference for performance under variable irradiance conditions. The team set out to develop a manner in which to compare inverter MPPT performance much like the California Energy Commission (CEC) efficiency testing. The goal was to improve cost of ownership by analyzing and improving techniques to track the MPP of the arrays.

- EMS Integration: PV systems (specifically, inverters) have the capability to be tied into building energy-management system controllers, allowing for optimization of time of use and local demand response to include inputs. The team set out to incorporate and develop system control techniques so that the major commercially available building

EMSs (Tridium, Echelon, Johnson Controls, etc.) could easily incorporate and leverage this resource into their overall control strategy.

- Intelligent String Combiner: The concept here is to move additional control and functionality out into the PV field to allow for improved safety, performance, and monitoring. As a long-term asset, monitoring further out into the array field is thought to allow for improved visibility as well as maintenance of the resource.
- Irradiance Forecasting: As penetration of PV continues to increase, the need for it to be deterministic in response becomes more important. The concept here is to investigate and develop techniques that could provide visibility into system performance both 6 hours ahead and 15 minutes ahead such that system operators could accurately predict how the aggregate resource is going to respond. Alleviating cloud-induced intermittency through forecasting is thought to be a major market changer to the PV industry.
- Utility Controls: As more and larger systems continue to be installed, the need to control them more like a traditional generator becomes increasingly important. The concept here is to interface the inverter-based system and leverage it to provide VAr support as well as real power support based on commanded (SCADA-controlled) or scheduled (time-based) criteria.
- Island Detection: Traditional island detection leveraging "perturb-and-observe" techniques begins to suffer in performance under high-penetration scenarios. The concept here is to develop an island-detection technique based on communications such that the shortcomings of traditional island-detection strategies could be overcome.
- System Integration: This task came at the conclusion of Stage 1 of the program – the team realized that with the broad scope of tasks listed above, there existed a need for a manner in which to bring them all together and interface with the inverter and external systems (BOS, SCADA, BEMS, and other third parties). This is the "communications vehicle" that is central to the concept paper. It provides two routes to get data and control signals in/out of the PV plant: 1) via the system controller (the local hub), and 2) via a cloud-based database and API (remote hub). The goal of the two-pronged approach is to provide flexible access to data and the controls needed by all stakeholders.

2.5 Market Update

The market need for advanced SEGIS functions has become reality earlier than expected. This is driven by current market realities and is caused by two related, but distinct, market factors. First, in the three plus years since AE submitted its initial SEGIS proposal, the idea of high-penetration PV has quickly gone from an almost hypothetical future-looking scenario to an issue that is current and immediate for a growing number of utilities in the U.S. Second, the costs of PV inverters has become a much larger portion of the overall PV system costs because PV module prices have fallen dramatically, while at the same time, inverter efficiency improvements are reaching a level of diminishing returns.

In response to these emerging trends, the team focused on solving the most urgent issues in the allocated timeframe that could offer the most needed features for customers and host utilities. AE did not receive its first request for an "advanced utility interactive feature" (like settable PF, VAr control, or low voltage ride through) until January 2010. Four short months later, AE received over a dozen requests for these features. Although SEGIS efforts were focused on enabling these very features, AE believed it would be several years until these features were integrated into existing UL 1741/IEEE 1547 regulations. Instead, utilities that are under pressure to comply with redundant power supply (RPS) demands and allow increasing rates of distributed generation interconnections have chosen to bypass UL 1741/IEEE 1547 entirely in preference for inverters that can help them solve their real, or perceived, protection and power-quality issues. The definition of the market requirements is quickly evolving as different organizations, including CALISO and the Electric Power Research Institute (EPRI), increasingly align to a common set of standards based on U.S. industry needs while pulling from more established standards like the German Bundesverband dert Energie (BDEW). However, AE did not wait for full industry alignment because foreign inverter manufacturers already are offering some of these features. For this reason, AE chose to commercialize settable PF and utility controls in lieu of standards refinement.

In parallel, AE also sought ways to avoid having its products become a commodity. Efficiency for larger inverters have begun settling in the 96% to 97.5% CEC efficiency range, and it is expected that the market will to continue to cluster more and more around the 97% to 98% range over the next year. At the same time, PV module prices have fallen rapidly, which is creating increased pricing pressure on inverters. Some of the few remaining opportunities for differentiation are more accurate MPPT and tighter BOS integration/optimization.

AE has begun productizing SEGIS functionality as it becomes available, rolling out enhanced energy harvest and utility control capability in 2011 to its PV-powered 260kW, 250 kW, 100 kW, and 75 kW inverter products.

3 SEGIS Task Descriptions and Goals

3.1 Maximum Power Point Tracking (MPPT)

This task was focused on optimizing energy harvest. With inverter electrical efficiencies reaching theoretical maximum, one of the last areas for optimization exists around total energy harvest (i.e., photons to power out). MPPT efficiency is as important a factor (though much less discussed) as inverter electrical conversion efficiency when addressing photons in to power out. The goals of this task within the SEGIS program were to:

1. Provide visibility to the industry that MPPT efficiency is as important as electrical conversion efficiency.
2. Develop a new configurable algorithm that provides optimal performance under all conditions (weather and PV module technology variables).
3. Develop a test process for quantifying MPPT efficiency to create a level playing field for industry discussion and comparison.

3.2 Building EMS Solar Energy System Integration

As PV systems become more widespread, they need to integrate with existing systems that have a logical reason for integration. Systems like this include facility EMSs, security systems, and utility SCADA systems. Future systems might include demand response systems, AMI, and home automation systems. For this SEGIS task the team focused on facility EMS integration. The goals of this task within the SEGIS program were to:

1. Implement a communications method that would integrate with any of the leading building EMSs on the market today.
2. Identify who the market leaders are and learn from them.
3. Leverage an existing communications standard that the building control industry is familiar with.
4. Make our data stream robust and publically available with supporting documentation.
5. Implement our own facility EMS to fully understand its value.

3.3 Intelligent String Combiner

Advanced BOS components have long been considered an opportunity for industry innovations. String combiners, sub-combiners, and re-combiners are a costly portion of the overall PV plant and have not yet been fully optimized for PV applications. The goal of this task within the SEGIS program is to explore this space and determine if the market is ready for an advanced combiner product. The goals changed some through the program, but are generally captured as follows:

1. Evaluate additional value-add functionality that a smart combiner could perform.
2. Perform a system analysis and optimization study to define cost/feature tradeoffs.
3. Develop a prototype combiner box based on the results and analysis of the study.
4. Commercialize the product line if combiner can be produced economically and good market adoption is expected.

3.4 Irradiance Forecasting

Expecting the eventual onset of grid parity led to another development area that will eventually be critical to the success of widespread PV as a utility generation asset: forecasting. Looking at parallels in other intermittent generation (like wind), the team recognized that knowing if and when an irradiance transient might occur would be valuable information as utilities look to more tightly integrate PV.

This task was initially selected because the impact of cloud-induced transients on PV output, and thus on AC voltage and frequency regulations, has the potential to limit PV grid penetration levels. Clouds can cause irradiance changes as high as 250 $W/m^2/sec$, which means that the PV power plant could go from 100% power output to 20% power output in just over three seconds. This can cause local and global frequency regulation problems for utilities, as has been well-documented in the literature. Making solar forecasting available to PV inverters can be used to tune MPPT algorithms for increased energy harvest, as well as to soften the fast AC output transient created by a fast irradiance transient via preemptively backing off of the array's MPP at a controlled rate.

This ability to predict power availability enables optimization of plant operation with storage, with conventional generation, and for energy trading. This task under the SEGIS program represented the most *research-oriented* task of the program, focusing essentially on complex mathematical models to predict cloud formation and thereby predict power availability. The goals of this task were to:

1. Develop a nearcast tool, approximately a 6-hour ahead forecast, ideal for optimal integration of storage and utility planning and trading operations.
2. Develop a nowcast tool, approximately a 10-minute ahead forecast, targeted to assist real time tuning and control to improve energy harvest, local power quality, and to reduce rapid transients on the grid.

3.5 Utility Integration

The primary goal of this task is to develop a set of utility control functions that would allow for operational improvements in energy handling with the distribution feeders of today's electrical networks. PF, curtailment, and ramp-rate variable control functionality were developed and tested throughout the SEGIS program. As utilities began bypassing the need for UL 1741-compliant products under their direct supervision, this functionality led to a number of enhancements in product development. SCADA connected and non-SCADA connected systems are currently being interconnected throughout the U.S., leveraging these developed features to solve interconnection challenges associated with high-penetration PV environments. A later goal that emerged while developing this technology was a common data map for communicating settings, operational control modes, and feedback of system operation. The end goals of the program were to develop the control functionality (PF, VAr, curtailment, ramp rate, etc.) as well as a suite of control options for interfacing the various system control needs (SCADA, BEMS, standalone operation).

3.6 Synchrophasor-Based Islanding

The goal of this task was to develop a low-cost synchrophasor-based island-detection algorithm (<$1300 increase) that would serve as an alternative to Power Line Carrier (PLC)-based approaches, and that can be considered an alternative to other algorithms currently in use. During the prototyping (Stage 2), the team set out to prove that the developed synchrophasor-based island-detection algorithm worked at all points in the system at all times. Additionally, this technology is designed to meet current or future versions of the IEEE 1547 standard for island detection. Continued revisions of the technology, including driving cost out of the initial prototype, comparing performance under real-world installation conditions, and continuing to demonstrate in live environments took place throughout the Stage 3 of the program.

3.7 Platform Integration

The platform (system) integration task was introduced at the end of Stage 1 of the SEGIS program. It was not originally envisioned, but came about as a vehicle to integrate the earlier task components. A platform-based approach was envisioned both to enable earlier task components and also to provide a long-term communications-centric platform to enable "smart grid" functionality yet to be defined. The goals of the platform integration task component were:

1. Develop an inverter-based Secondary Controller (system controller) that would provide advanced communications, control, data aggregation, and reporting – the communications-centric platform.
2. Develop a central database with API data access layer to support stakeholder needs from AE reliability engineering to utilities and developers that have a need for access to power plant operational data.

At the conclusion of Stage 1, the following SEGIS structure was envisioned and diagramed (Figure 1), illustrating the inter-relationship of all the SEGIS task components.

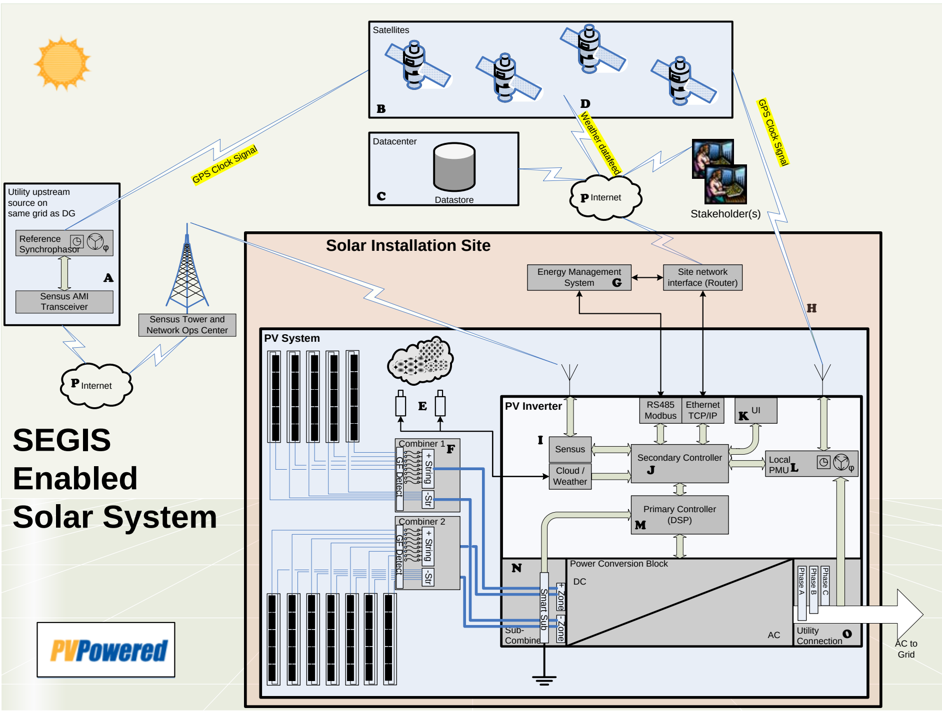

Figure 1: SEGIS block diagram.

4 SEGIS Task Results

4.1 Maximum Power Point Tracking (MPPT)

4.1.1 MPPT Efficiency Testing Plan

This section describes the results of the effort to create a standardized testing profile for quantifying MPPT efficiency. This proposal was presented for industry feedback and acceptance at the 37th IEEE PVSC as a starting point for developing a national standard to accomplish such an endeavor.

The effectiveness of MPPTs is an important factor in the energy harvest of a PV system. Inverter manufacturers want to maximize the effectiveness of their MPPTs, and plant developers desire to choose inverters with the most effective MPPTs to maximize their return on investment. However, comparing MPPTs against one another is challenging because the most common figure of merit, the MPPT efficiency, is a static metric that depends on the characteristics of the PV array and on the time variation of the irradiance. To enable meaningful comparisons between MPPTs, this paper proposes a standardized irradiance profile for use in determining MPPT efficiency. The proposed irradiance profile is designed to minimize bias in the results and maximize reproducibility. The irradiance profile, its rationale, and its use are described herein. MPPTs are intended to keep a PV array operating at its maximum power point (MPP), and thus at peak efficiency, under all temperature and irradiance conditions and with any type of PV technology. The figure of merit most commonly used to compare MPPTs against one another is the "MPPT efficiency," η_{MPPT}, defined as shown in Equation 1.

$$\eta_{MPPT} \equiv \frac{\int_0^T p_{PV}(\tau)\, d\tau}{\int_0^T p_{max}(\tau)\, d\tau} \qquad (1)$$

In this equation, $p_{pv}(t)$ is the PV output power at time *t*; $p_{max}(t)$ is the actual theoretical maximum power the array could have produced at time *t*; T is the time period over which η_{MPPT} is calculated; and τ is the time variable for integration. A wide array of control algorithms have been devised to achieve this goal, with varying degrees of success. Most are based on the classical "perturb-and-observe" (P&O) method, also called the hill-climbing or gradient method. In P&O, the MPPT measures the PV array output power P_1 at PV array DC voltage V_1, then perturbs the PV array DC voltage to V_2 and measures PV output power P_2. If $P_2 > P_1$, then the MPPT concludes that moving from V_1 to V_2 moved the PV array closer to its MPP, and the MPPT perturbs the voltage again in the same direction. If $P_2 < P_1$, then the MPPT moved the voltage away from the MPP, and the direction of perturbation is reversed. This classic MPPT can achieve η_{MPPT} values of over 99%, and when optimized it can have a fast response speed. However, it has at least two well-known shortcomings:

1. First, it sometimes does not perform well if irradiance conditions are changing rapidly (i.e., the rate of change of irradiance, dG/dt, is high) because P&O assumes that any power change it detects is caused by the change in voltage; it cannot account for power changes caused by changes in irradiance. (For recent experimental results on this subject, see References.)

2. Second, it tends to become erratic at low irradiance levels because the P-V curve tends to flatten out, which makes dP/dV small and difficult to discern. This same problem can occur when P&O is used with PV arrays having very low fill factors.

Several MPPT methods have been proposed to address these shortcomings. In the literature (see References), methods based on P&O and some entirely new algorithms have been described. In industry, there are countless variants of P&O, using variable and adaptive parameters, various "wait" and "observe" periods, and (in some cases) even irradiance measurements. In essence, all of these variants aim to address the same two fundamental weaknesses noted above: the need for good tracking when dG/dt varies over a wide range, and the need to maintain sensitivity for all PV technologies and irradiance levels. With such an array of MPPT options, it becomes important to be able to compare MPPT concepts against one another. The MPPT efficiency is the obvious means by which to do this, but the foregoing discussion makes it clear that the conditions under which η_{MPPT} is measured:

1. must be standardized, so that the irradiance inputs are always the same; and
2. must include both high and low dG/dt conditions, and high and low irradiance conditions.

There is as yet no stated agreement as to how η_{MPPT} should be measured. One logical alternative that has gained some acceptance in Europe proposes an alternative standard test protocol (actually, a standard irradiance profile) that addresses the concerns described above and provides a comparative measure of η_{MPPT} in much the same way as Standard Test Conditions (STC) PV cell efficiency gives a comparative measure of the performance of PV technologies. The test is easy to run in computer simulation or in the laboratory using a PV-array simulator. The proposed protocol is believed to be easier to use and may also lead to more reproducible results because it involves only one continuous test.

The proposed MPPT test protocol uses the irradiance versus time profile shown in Figure 2.

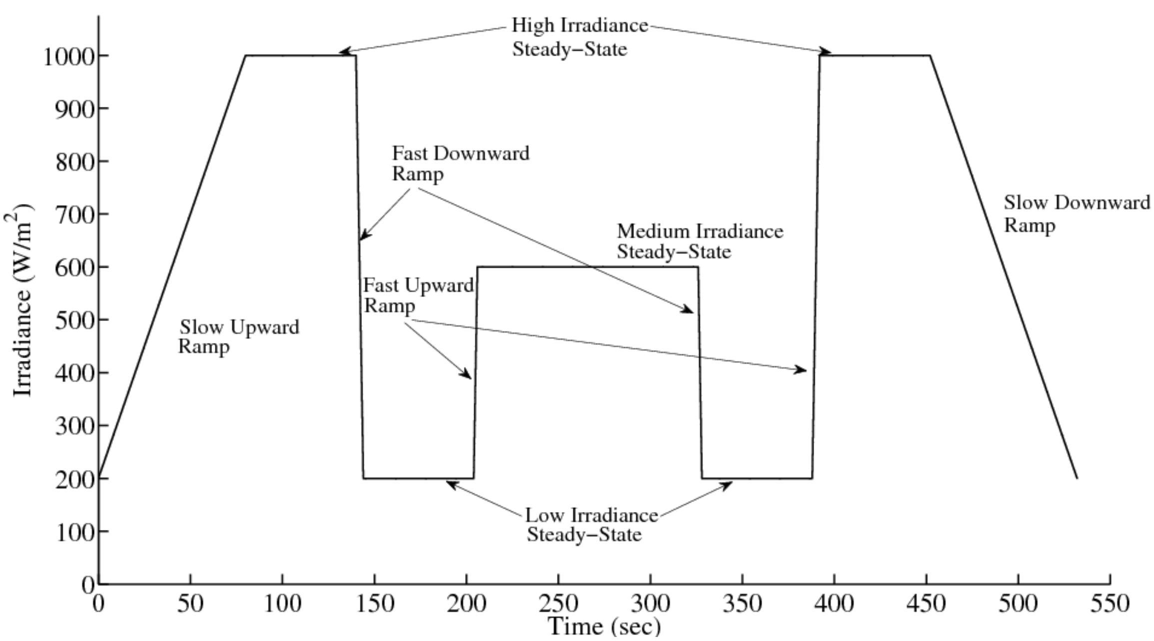

Figure 2. Proposed standardized irradiance profile.

The features of this proposed irradiance profile are given in Table 1. The profile can be subdivided into static and dynamic sections, as shown in Figure 3.

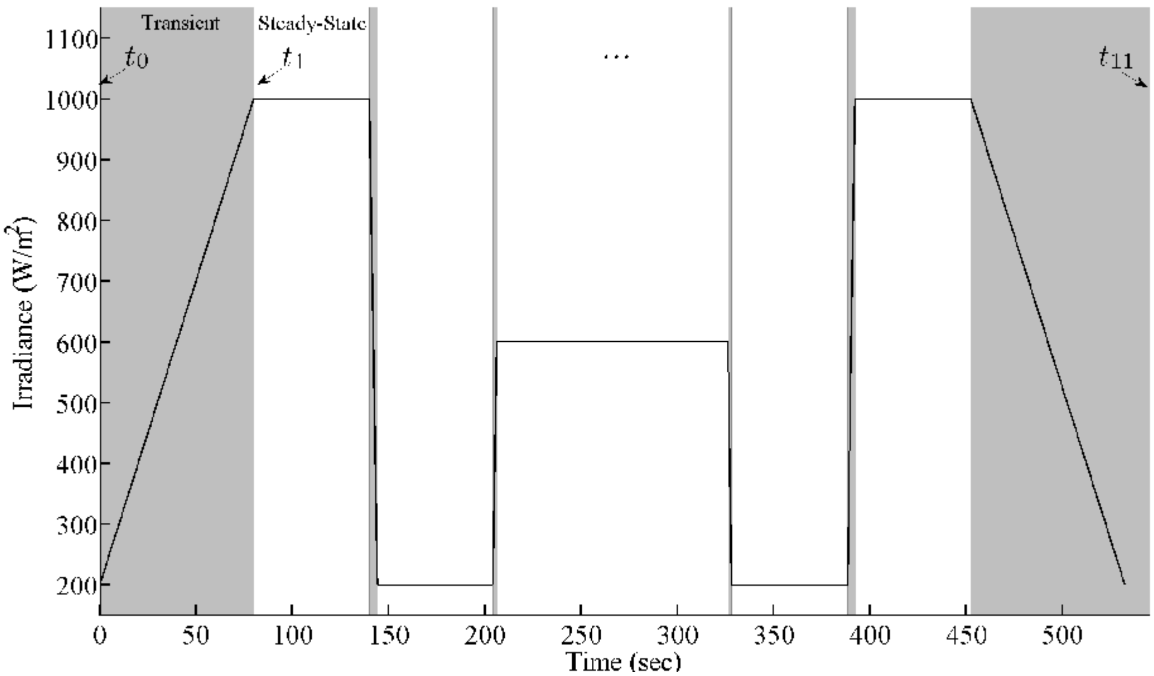

Figure 3. Proposed standardized irradiance profile with static and dynamic sections separated.

With these divisions, separate static and dynamic η_{MPPT} values can be calculated using Equations (2) and (3):

$$\eta_s = \frac{1}{N_s} \sum_{k\ even} \frac{\int_{t_{k-1}}^{t_k} p_{PV}(\tau)\, d\tau}{\int_{t_{k-1}}^{t_k} p_{max}(\tau)\, d\tau} \tag{2}$$

$$\eta_d = \frac{1}{N_d} \sum_{k\ odd} \frac{\int_{t_{k-1}}^{t_k} p_{PV}(\tau)\, d\tau}{\int_{t_{k-1}}^{t_k} p_{max}(\tau)\, d\tau} \tag{3}$$

where $N_s = \sum_{k\ even} k$ and $N_d = \sum_{k\ odd} k$ are the number of segments in the static and dynamic regions, respectively.

Table 1. Parameters of the proposed irradiance profile.

Parameter name	Value	Units
Starting irradiance	200	W/m^2
Slow upward ramp rate	10	$W/m^2/sec$
Slow upward ramp time	80	sec
Length of high and low steady-state periods	60	sec
High steady state irradiance level	1000	W/m^2
Middle steady state irradiance level	600	W/m^2
Length of middle steady-state period	120	sec
Low steady state irradiance level	200	W/m^2
Fast downward ramp rate	-200	$W/m^2/sec$
Length of first fast downward ramp	4	sec
Length of second fast downward ramp	2	sec
Fast upward ramp rate	200	$W/m^2/sec$
Length of first fast upward ramp	2	sec
Length of second fast upward ramp	4	sec
Slow downward ramp rate	-10	$W/m^2/sec$
Slow downward ramp time	80	sec

The reasoning for separately examining static and dynamic MPPT efficiencies is to preserve knowledge of the inverters' separate MPPT behaviors. If total efficiency from the test is computed using (1) over the entire time interval, the relatively high efficiencies during static conditions would tend to mask MPPT performance deficiencies during transient events. The proposed standardized MPPT test protocol was developed under the following considerations. The purpose of the test is to derive an η_{MPPT} value that can be used to compare the performance of one MPPT against another, using a protocol that is "realistic" in the sense that it puts the MPPT into conditions that it will see in the field. However, the test needs to be easy to use in computer simulation (even with detailed representations of the power electronics) or in the laboratory with a PV array simulator.

The test needs to represent high, medium, and low irradiance conditions without bias toward any particular condition. Similarly, both fast and slow ramp conditions need to be represented. It is well known from classical controls theory that step and ramp tracking place different demands on a controller, so the proposed irradiance profile includes both, thereby subjecting the MPPT to a rigorous test from a controls perspective.

The proposed protocol starts from an irradiance of 200 W/m^2. It thus excludes startup and shutdown procedures, focusing solely on MPPT performance. The "step" function is actually a ramp whose dG/dt is set to a worst-case realistic value of 200 $W/m^2/sec$, which comes from field measurements. It is important to note that this high ramp rate is only rigorously applicable to PV arrays that are rather small in area. The 200 $W/m^2/sec$ ramp rate was measured using a silicon photodetector with an active area of 1 cm^2, and thus these ramp rates indicate the shape of the edges of the cloud shadow. They do not account for the speed with which the cloud shadow passes over the array; this happens nearly instantly for a pyranometer, but can take several seconds for a large array. The following procedure is recommended for appropriately scaling the fast ramp times for testing MPPTs in larger inverters. Consider the first fast downward ramp and assume that the PV array is square. Then, we note the following relationships. The area of the array (in m^2) is calculated as:

$$\boldsymbol{A = \frac{P}{G\eta}} \tag{4}$$

where P is the nameplate DC array power, G is the STC irradiance (1 kW/ m^2), and η is the STC efficiency of the PV array. The length of one side of the array (in m) is calculated as:

$$\begin{aligned} \boldsymbol{l} &= \boldsymbol{\sqrt{A}} \\ &= \boldsymbol{\sqrt{\frac{P}{G\eta}}} \end{aligned} \tag{5}$$

The time (in seconds) required for a cloud shadow to cross a distance of l is:

$$\begin{aligned} \boldsymbol{t} &= \boldsymbol{\frac{l}{v}} \\ &= \boldsymbol{\frac{\sqrt{P}}{v\sqrt{G\eta}}} \end{aligned} \tag{6}$$

where v is the cloud velocity in m/sec.

Note that η, P, and v are the only input parameters required from the user if the array is square; if it is not square, the user can start directly with the value of l in Equation (6). To find the time length of the fast downward ramp, one starts with the initial time of 4 seconds, then adds the time t computed from the equations shown in (4)-(6).

A simpler formula can be derived if a few reasonable assumptions are made. For PV systems in the field, the following values for efficiency and cloud velocity can be considered typical, or at least representative:

$$\boldsymbol{\eta = 10}\%$$

$$\boldsymbol{v = 15} \text{ m/sec}$$

Using these values, Equation (6) becomes:

$$\boldsymbol{t} = \frac{\sqrt{\boldsymbol{P}}}{\mathbf{150}} \tag{7}$$

The value of t for any inverter size can now be found, and the length of the first downard fast ramp, t_{down}, should then be set to $t + 4$ sec:

$$\boldsymbol{t_{up}} = \boldsymbol{t} + \mathbf{4} \text{ (sec)} \tag{8}$$

The time lengths of the other ramps are found in the same way with the starting time set to 4 or 2 seconds, as appropriate. For example, assume that one wishes to compare MPPT algorithms being employed in a 250 kW inverter. For 250 kW, $t = 3.333$ sec, and we have

$$t_{up} = 7.333 \text{ sec}$$
$$t_{down} = 5.333 \text{ sec}$$

Note that the correction factor t that accounts for the size of the array is negligibly small for residential-size inverters, and could actually be neglected entirely even at the 250 kW level without too much loss of reasonability for present purposes. It is important to note that the derived η_{MPPT} value will not necessarily be a prediction of what a specific MPPT will do on a specific site. In this, the philosophy adopted is similar to that used in deriving the STCs used for PV cells. The fact that the proposed protocol attempts to avoid bias toward any one condition is actually the reason why the standardized MPPT test protocol will not necessarily predict actual field MPPT performance. For actual field predictions, the site irradiance conditions will dominate the performance of the designed system at each specific locale.

4.1.2 RCA MPPT Algorithm

The development, testing, and commercialization of the Rate Corrected MPPT Algorithm (RCA) was a major accomplishment of the AE-led SEGIS team over the course of the three-year program. The algorithm continued to evolve throughout the duration of the program to include features and functions that emerged from new technologies introduced to the PV industry while remaining true to its roots as a central difference equation capable of responding to fast and slow irradiance events without stepping in the wrong direction. The algorithm is discussed below, including highlights and functional capabilities.

4.1.2.1 Basis of the RCA MPPT

The RCA is based on a central difference equation for rapid response under dynamic irradiance conditions while minimizing loss under steady state or static conditions. The developed algorithm allows for specific module tuning of the gains associated with the step size as well as dither depth associated with its response. The RCA was developed to overcome the shortfalls of classical P&O approaches (irradiance changes causing missteps, energy loss at steady state conditions, slow response to dynamic irradiance changes) while preserving a simplistic approach to determining the true maximum power point of the connected PV array.

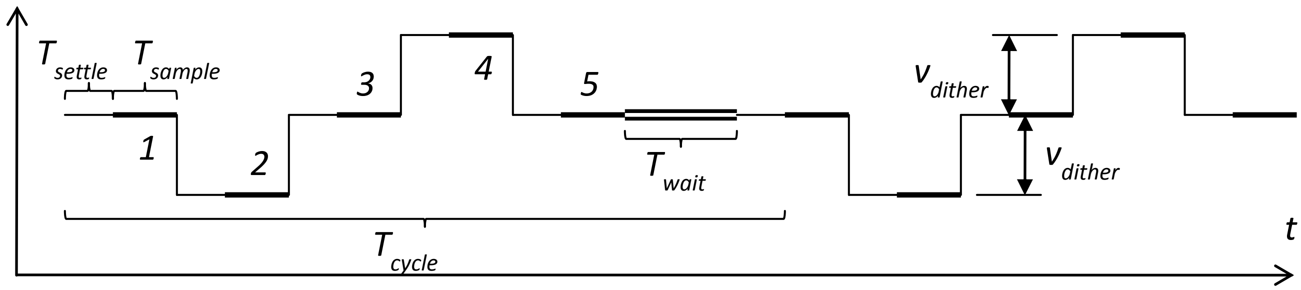

Figure 4. Simplified Voltage/Timing Plot of RCA MPPT algorithm.

To summarize the concept of the RCA MPPT algorithm the above (Figure 4) highlights the voltage versus time response leveraged to determine next-step criteria. The RCA is a five-step cycle in which five power measurements are taken at three DC voltages: the current MPP voltage, the current MPP voltage minus the current dither voltage, and the current MPP voltage plus the current dither voltage. The first, middle, and last power measurements are taken at the current MPP voltage, and this redundancy is the basis by which the change in power due solely to irradiance change may be parsed out from the change in power due to changing voltage. At the end of each cycle, a new MPP voltage and dither voltage are determined and subsequently commanded. Optimizations for differing PV module technologies can be made by tuning the step voltage (from current Vmp to next Vmp) as well as by tuning the dither depth voltage. In addition to the simplified parameter set shown above, there exist inputs to the MPPT algorithm for weather station inputs as well as commanded values. As a final note, the RCA has been developed in a manner that allows for broad, narrow, and fixed DC voltage operation to accommodate the many DC optimizers that have emerged in the market in recent years.

4.1.2.2 Commercialization

The RCA is the current production version of MPPT used in the AE “PV Powered” commercial products. Its proven energy harvest gains, as well as its effective operation under dynamic and steady state conditions, will allow for the PV installations to harvest more energy over their service lifetime. As new technologies enter the solar PV marketplace (dc optimizers, string level dc/dc conversion, etc.), the developed and commercialized algorithm is well suited to meeting the needs of these technologies while offering a low-cost solution for today’s existing module and BOS hardware.

4.2 Building EMS Solar Energy System Integration

To add value to the system without increasing cost, the team needed to implement a communications method that would integrate with any of the leading building EMSs available on the market today.

To accomplish this, the team developed the following goals:

1. Identify who the market leaders are and learn from them.
2. Leverage an existing communications standard that the building control industry is familiar with.
3. Make the data stream robust and publically available with supporting documentation.
4. Implement an internal facility EMS to fully understand the technologies as well as the value of this implementation.

To address these goals, the team conducted market research to identify the leaders within the building controls industry. The team studied relevant communications protocols, how they are being used, and what type of data are required to support them. The four leading providers that were identified are Delta, Echelon, Johnson Controls, and Tridium. Each of these providers has its own unique product offering and present unique challenges for integration. Through market research, the team concluded that the following requirements would allow integration with most of the EMS solutions available today:

- Modbus is a common protocol used among all of the providers and could be the single protocol implemented in the inverter.
- RS-485 and transmission control protocol (TCP) are the preferred physical layers of the Modbus protocol to be used.
- Data stream shall include relevant system-level data such as voltage, current, watts, kWh, fault codes, and basic commands such as enable/disable, PF control, and curtailment.
- Modbus point maps need to be published for control contractors to use.

There were several key elements that needed to be accomplished for this task to be successful. First, the team needed to implement Modbus communications within the inverter and document them. Second, the team needed to procure EMS hardware from each of the four industry building controls and energy-management providers for bench top testing with the inverter. Third and finally, the team needed to design and implement a building control EMS within the facility to implement real-world testing and advanced control algorithms for prototype development as well as productization.

4.2.1 Modbus Implementation

Modbus is now a standard feature in all AE inverters. Modbus is implemented using AE's existing communications card known as the PVM-2020, which comes standard at no additional cost with every commercial AE inverter sold today. Modbus capability is also implemented in the SEGIS communication platform – the secondary controller. Both platforms allow the facility EMS to communicate with the inverter via RS-485 or TCP. Because the PVM2020 is readily available today, AE has the supporting Modbus register map available in the product manual that ships with the inverter. It is also published and publically available on AE's website.

4.2.2 Bench Test Systems

The purpose of bench testing was to implement and test communications and functionality with a variety of different energy-management solutions using the Modbus protocol via RS-485 and

TCP. While all of the energy-management solutions can communicate with Modbus devices, each has its own unique requirements and implementation.

Figure 5 below shows each of four testing platforms mounted and wired in the SEGIS test enclosure. This enclosure enabled compatibility of the controllers on AE's network as well as providing a common coupling point for the SEGIS 75 kW inverter.

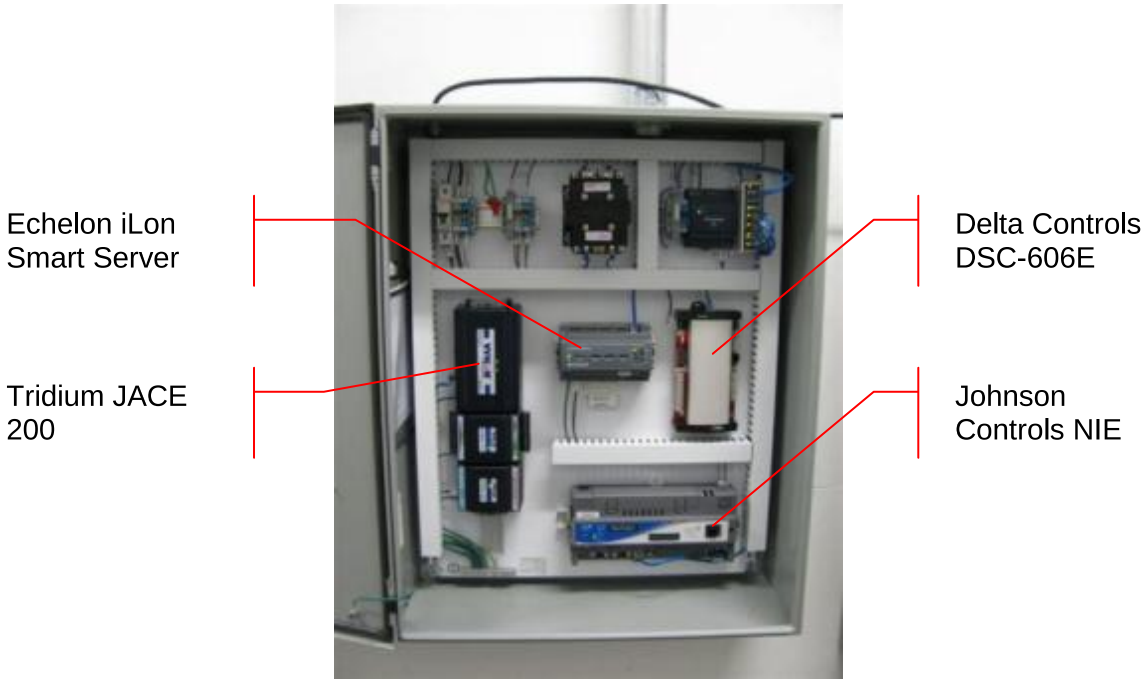

Figure 5. SEGIS bench test enclosure.

4.2.2.1 Delta

Delta Controls is a native BACnet solution that focuses on traditional building control of lighting, heating, ventilation, and air conditioning (HVAC), and security systems. The Delta platform can communicate with Modbus devices, but requires a firmware change in the controller as well as a purchase of Modbus credits to do so. The credits are purchased in 10-credit increments and are required for every Modbus device on the network. The Delta Controls DSC-606E controller is shown in Figure 5. ORCAview software is required for point map development, Modbus firmware implementation, graphics development, and controller commissioning.

4.2.2.2 Echelon

Echelon was identified as a key component supplier for EMS testing because it is already making a presence in the PV industry. Echelon is most notably known for their LonWorks communications protocol, which is used by some of the largest EMS manufacturers such as Honeywell, Distech, and others.

Echelon's i.Lon SmartServer is a very flexible yet robust controller. This controller allows Modbus devices and other non-LonWorks communicating devices to be easily integrated into any LonWorks-based EMS.

Modbus integration with the i.Lon smart server is done through the onboard engineering tools, which allow the integrator to set up Modbus networks using either RS-485 or transmission control protocol/Internet protocol (TCP/IP). Point mapping of the Modbus register map can also be done locally, or .xml files can be written and uploaded via a file transfer protocol (FTP) connection. Once the point maps are completed and the controller is commissioned, the i.Lon can be used as a standalone server to host custom graphics and provide trending and alarming, or it can be configured as another node on a much larger LonWorks network reporting to a supervisory controller.

AE was successful in establishing communications between the i.Lon and the inverter using RS-485 and TCP. The integration, once completed, was capable of indexing the available data points in the inverters Modbus register map as well as command the inverter using the available enable and disable registers.

4.2.2.3 Johnson Controls

Johnson Controls is one of the most recognized names in the building control industry and is continuing to expand its business in battery technology, renewable energy, and building energy services.

Johnson offers two platforms in their product line up: the proprietary Metasys platform and the Facility Explorer, which is built on Tridium's Niagara AX framework.

For testing purposes, AE used the Metasys Network Integration Engine (NIE) shown in Figure 5. This platform is a powerful supervisory controller and can be used as a standalone webserver to collect and host data or as a gateway to integrate Modbus devices into a larger BACnet or N2 control system.

AE worked directly with Johnson Controls to get the device to communicate with AE inverters. The device itself needed to be configured by another group within the Johnson Controls organization. Johnson Controls requires all the register maps for the devices needed to integrate or be monitored. Johnson then configures per specification and ships the controller ready for use.

4.2.2.4 Tridium

Tridium offers one of the most flexible solutions on the market and have focused on communication protocol interoperability with their Niagara AX platform. AE chose Tridium because of its open-source architecture, allowing for integrations with any number of EMS hardware providers who have OEM'd the Niagara AX platform (e.g., Honeywell, Johnson Controls, Siemens, Distech, Novar, Emon Demon).

AE's bench testing involved using the Vykon Jace-200 controller shown in Figure 5. The controller requires a Modbus license to activate the functionality within the controller. All of AE's development was completed in-house, and was successful with this controller. The team was able to establish communications with the PVM2020 using RS-485 and TCP, and with the secondary controller over TCP. Point maps and graphics have been created, but still require refinement for end use. This controller's flexibility led to it being used for the solar PV field monitoring as described below.

4.2.3 Facility EMS

The facility EMS was implemented to provide a real-world test case to determine and show the value of solar integration. The system consists of several components; the first being an HVAC and lighting control system, which was implemented using the Johnson Controls Metasys platform. This system was chosen for its proven platform performance, involvement within the PV industry, and the availability of local support if the system requires expansion. With this completed system, AE has the ability to monitor and control (both locally and remotely) the HVAC equipment, office-space temperature, warehouse temperature, lighting zones, and exhaust fans used throughout the facility. Figure 6 represents the completed EMS showing controllers and communications methods, including optional Modbus integration through the NIE.

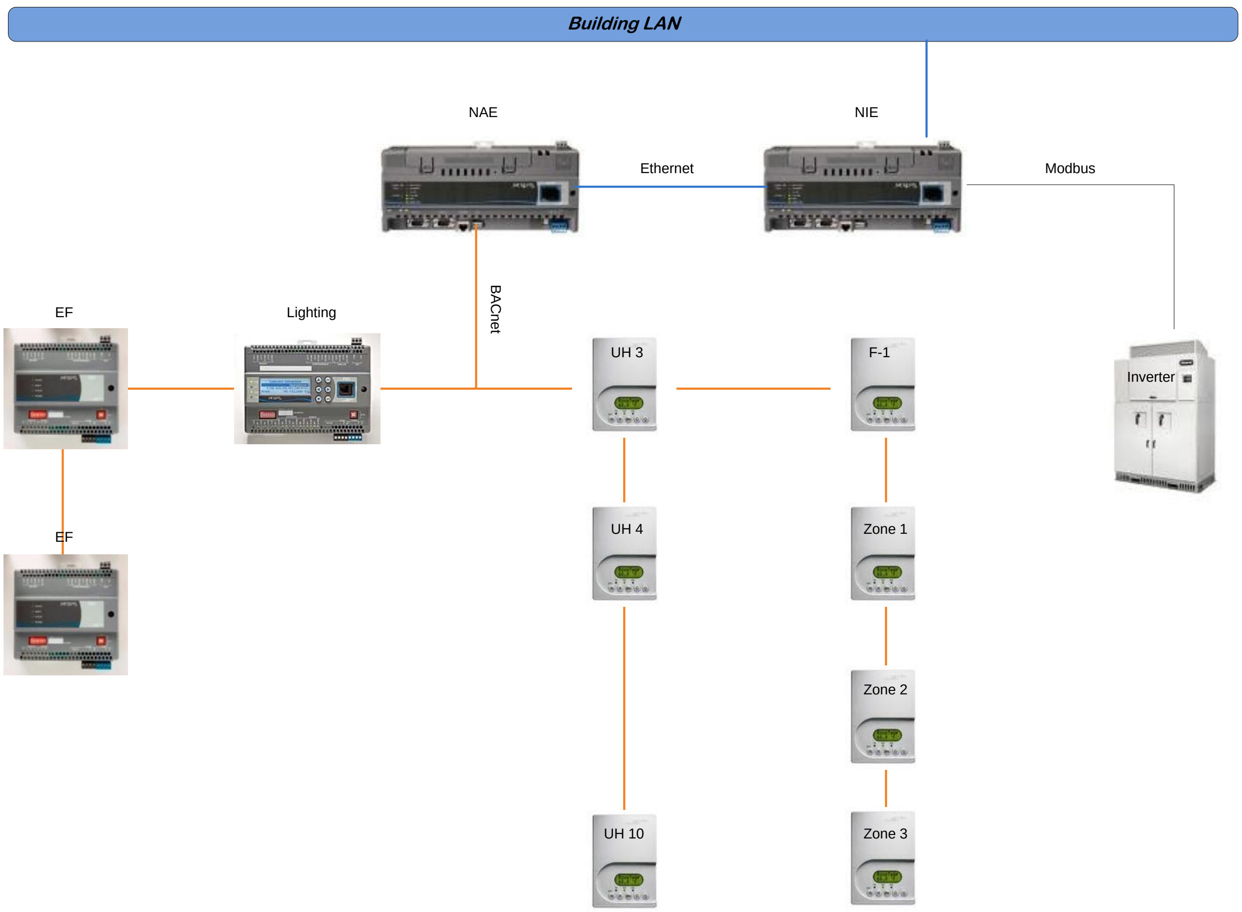

Figure 6. Facility EMS.

The second portion of the AE EMS consists of the building demand meters. For the purpose of building demand metering, the team utilized a Siemens WL communicating circuit breaker (Figure 7) and Siemens Sentron PAC 3200 meters (Figure 8). The Siemens WL communicating breaker is located at the service main coming into the facility and monitors total system load. The meter has the ability to communicate using a Modbus data stream over RS-485 and is tied into the facility EMS through the JACE-200.

Figure 7. Siemens WL communicating breaker.

Figure 8. Siemens Sentron PAC 3200 meter.

Siemens PAC 3200 meters for branch circuit metering are leveraged and communicate via Modbus TCP. These are tied into the control system through the Niagara AX platform.

Both of these meters record a broad data-stream, including voltage, current, total harmonic distortion, PF, phase angles, apparent power, reactive power, real power, system status, meter status, and more.

The third portion of the facility EMS is the integration of the PV field. The PV field is monitored, leveraging the JACE-200. The JACE-200 also has control of the SEGIS 75 kW inverter, SEL-734 meter, and the AE IntelliString combiner boxes, as shown in Figure 9.

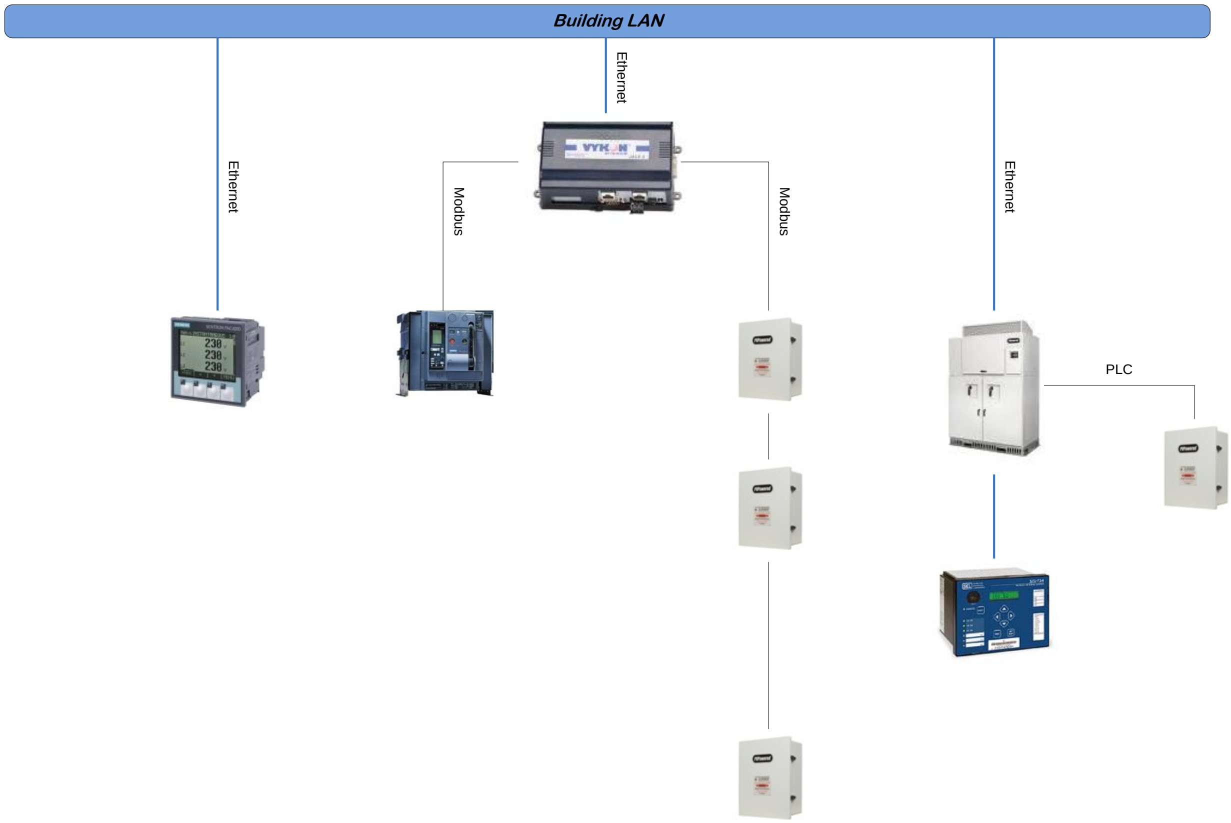

Figure 9. Solar field integration.

The Jace controller that is used to collect system-level data and control the inverter is integrated with the Johnson Controls Metasys system through a BACnet TCP connection. This integration gives the facility the ability to make intelligent decisions on how to control loads, such as HVAC equipment and lighting loads, based on such parameters as solar production, system status, and demand metering. This allows the system to notify building maintenance when there is a problem in the system, lock out the inverter when maintenance is being done, shut down the inverter in the event of a fire, and handle a variety of other unusual conditions.

4.2.4 Summary

The team learned that PV integration with a facility EMS is achievable today, but that it is currently being implemented on a very small scale. As industries continue to see commercial rooftops being filled with PV energy collection components, it will become crucial that PV inverters easily integrate with facility EMSs. This integration will allow facility owners and maintenance teams to keep a closer watch on energy investments and allow building systems to make intelligent decisions about how to control loads while keeping energy consumption and costs down, thus potentially accelerating their ROI.

Until recently, the building control industry has only had to deal with HVAC equipment, lighting, security, and fire and life safety systems; most of those systems are driven by time-of-day or temperature set points. Solar PV is a new concept for the industry, and the market is not yet certain of the value of the ability to control an inverter through an EMS. It is the solar industry's job to educate and provide knowledge by creating white papers and documentation on how and why this effort should move forward. The other aspect will be to work with EMS manufacturers and standards bodies on application-specific controllers, much like they have for HVAC equipment and lighting, to develop best-practice guidelines and plug-and-play functionality.

A successful foundation for EMS integration was developed in Stage 2. Opportunities for advanced relational control algorithms and storage integration with the SEGIS inverter system were enabled, and the team deemed the work on EMS integration complete at the conclusion of Stage 2. Effort continues to be made to enable and drive connection of facility EMSs to PV inverter systems. Many examples exist where PV and EMSs are being connected, but the team believes the industry now needs to reflect on this capability to determine what market needs might arise next. An obvious opportunity that would drive the need for EMS integration is that of an economically viable storage solution. Until then, widespread integration of EMS and PV inverter systems is not expected. The team did not pursue integration of energy storage or advanced relational controls for Stage 3, given the low likelihood for early adoption. The team believes industry will build on the foundation laid in Stage 2 and drive new needs for EMS integration.

4.3 Intelligent String Combiner

During Stage 1 of the SEGIS program, the team performed system analysis to understand typical problems experienced in the field that advanced balance-of-system components could address. The team focused on ground faults, as they represent an intermittent problem that can bring an entire inverter subsystem down until the fault is isolated. Further, this type of fault can be quite difficult to locate and address, so the team deemed it to be low-hanging fruit.

The team considered:

- Time to isolate and repair faults.
- Concept designs.
- Preliminary bill-of-materials and costs.
- Additional benefits that could be provided in a design that could detect faults.
- Emerging requirements around arc faults.

The team envisioned a line of smart combiners/sub-combiners that could enable quick detection and isolation of the problem with tight integration to the inverter communications platform.

During Stage 1, the parameter space was mapped, and a preliminary approach was defined. During Stage 2, the approach was further refined, and a prototype was developed. The functional prototype was tightly integrated, enabling easy installation, communications connection, and troubleshooting. Data were fed back seamlessly to the communications platform (secondary controller) in the inverter where it was able to act on inputs from the field and pass these data up to the developed SEGIS database. During the final prototype evaluation at the conclusion of Stage 2 of the SEGIS program, a successful prototype demonstration was performed.

However, the team decided not to carry the string combiner into the final stage of the SEGIS program for the following reasons:

1. An inverter communications platform or hub is required to enable the successful commercialization of this product.
2. Commercializing the inverter communications platform was the focus of Stage 3 – it would not be ready to enable commercialization of the combiner in the same timeframe.
3. Developing a commercial advanced string combiner product line in parallel with the communications platform development would have over-extended the team and added risk to the other components committed to successful commercialization in Stage 3.
4. The non-technical risk of commercialization and adoption of the advanced string combiner that could have limited market acceptance related to existing *National Electrical Code* (*NEC*®) requirements.

4.4 Irradiance Forecasting

4.4.1 Overview

This task represented the most technically difficult task that the team undertook. The goal was to develop irradiance forecasting tools with two focus areas: 1) Nearcast, a 6-hour ahead forecast that utilities and marketers could use to predict available PV power, and 2) Nowcast, a 10-minute ahead forecast that would serve to support intermittency mitigation challenges. The specifications developed for the tool were as follows:

Nearcast Specifications

- Forecast window: ≥ 6 hours ahead
- Time resolution: Forecasts updated at ≤ 30 minute intervals
- Spatial resolution: ≤ 1 km
- Geographical area coverage: Must be able to cover an entire utility control area on the order of 1×10^4 km^2
- Forecast parameters required:
    - Global horizontal irradiation or atmospheric clearness index
    - Surface temperature
- Data delivery: Any standardized file format, such as grib2, delivered via a standard transmission channel (TBD)

Nowcast Specifications

- Forecast window: ≥ 10 minutes ahead
- Time resolution: Forecasts updated at ≤ 1 minute intervals
- Spatial resolution: ≤ 10 meters
- Geographical area coverage: Radius of 10 km centered on PV power plant (just over 300 km^2)
- Forecast parameters required within the area of coverage:
    - Cloud location
    - Cloud transmissivity
    - Cloud velocity

- Data delivery: Any standardized file format, such as grib2, delivered via a standard transmission channel (TBD)

The team partnered with the Cooperative Institute for Meteorological Satellite Studies (CIMSS) at the University of Wisconsin-Madison to develop the fundamental irradiance forecasts. The approach leveraged satellite data and complex modeling/analysis tools to develop the forecasts. In summary, during SEGIS Stage 2, the team moved the nearcast tool from Technology Readiness Level (TRL)-3+ to TRL-5+, and developed a clear path to TRL-7. However, there is significant development needed to bring the tool to a commercializable state. Since the focus of Stage 3 is commercialization, the team chose to discontinue development of this task as part of the SEGIS program.

4.4.2 Results

First, investigators at the CIMSS established a version of their CRAS (CIMSS Regional Assimilation System) tool at its current capability level suitable for use in developing the post-processing software. This CRAS nearcasting tool produces output every six hours, with each covering a twelve-hour ahead window. Its spatial resolution is 15 km (that is, each “pixel” is 15 km × 15 km) with the resolution largely being limited by the particular Geostationary Operational Environmental Satellite (GOES) instrument being used, called a sounder. CIMSS investigators modified the CRAS to produce output files in grib2 format, containing all parameters needed for irradiance nearcasting suitable for PV output prediction, and to do so over the northwestern U.S., including Washington State, Oregon, and northern California.

Next, the CIMSS investigators set about improving the CRAS model for this application. The first step was to incorporate data from a second GOES instrument, the imager, which has much finer resolution than the sounder and will enable the new CRAS nearcasting tool to have a resolution of 5 km. The second step was to add rudimentary cloud physics models to enable the CRAS tool to predict cloud formation over the nearcast time period. The new 5 km CRAS tool is now in the testing stage by CIMSS investigators.

In parallel with that effort, NPPT engineers set about developing post-processing software in the matrix laboratory (MATLAB) environment to convert the raw global horizontal irradiance predictions from the CRAS nearcaster into PV plant AC power outputs. The user accesses the software through the Graphical User Interface (GUI) shown in Figure 10.

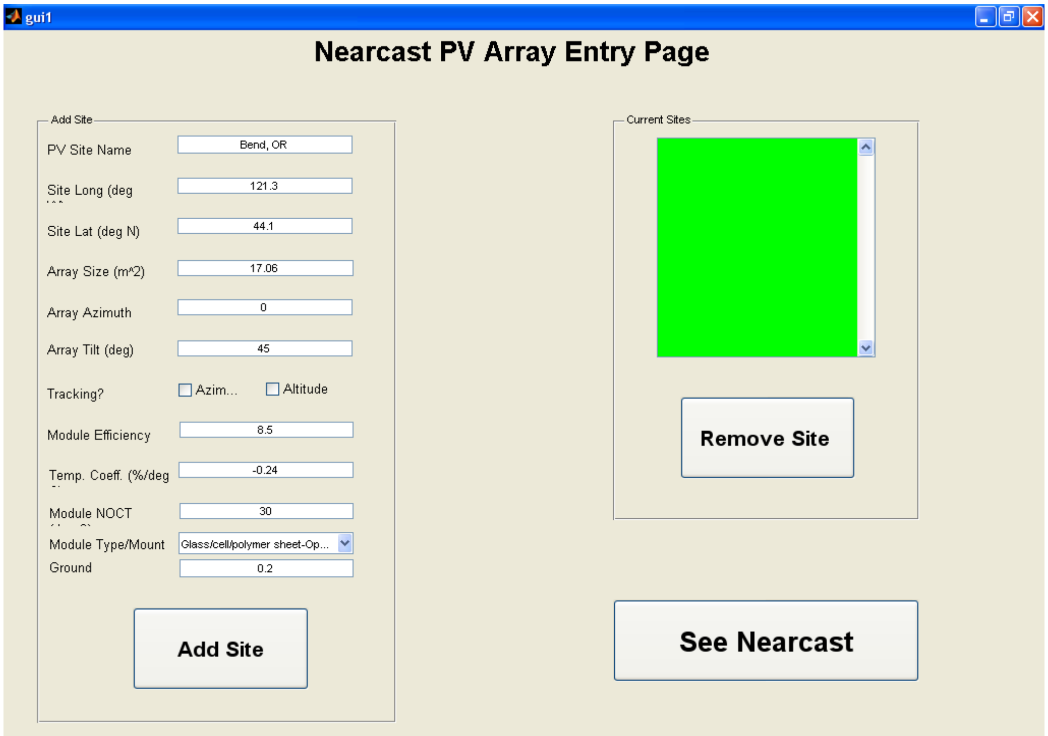

Figure 10. Graphical user interface for the nearcasting software.

The user enters a descriptive site name, the site latitude and longitude, the physical array size (active area), the azimuth and tilt angles, the STC module efficiency and temperature derating coefficient, and the ground albedo. The user also selects the PV module and mounting type from a drop-down menu; the available choices in this drop-down menu are visible in Figure 11. The user also has the option of setting two check boxes for azimuth or altitude tracking – the user can set either (one-axis) or both (two-axis) of these check boxes. The site settings in Figure 10 have been set to match those of the AE test site in Bend, Oregon.

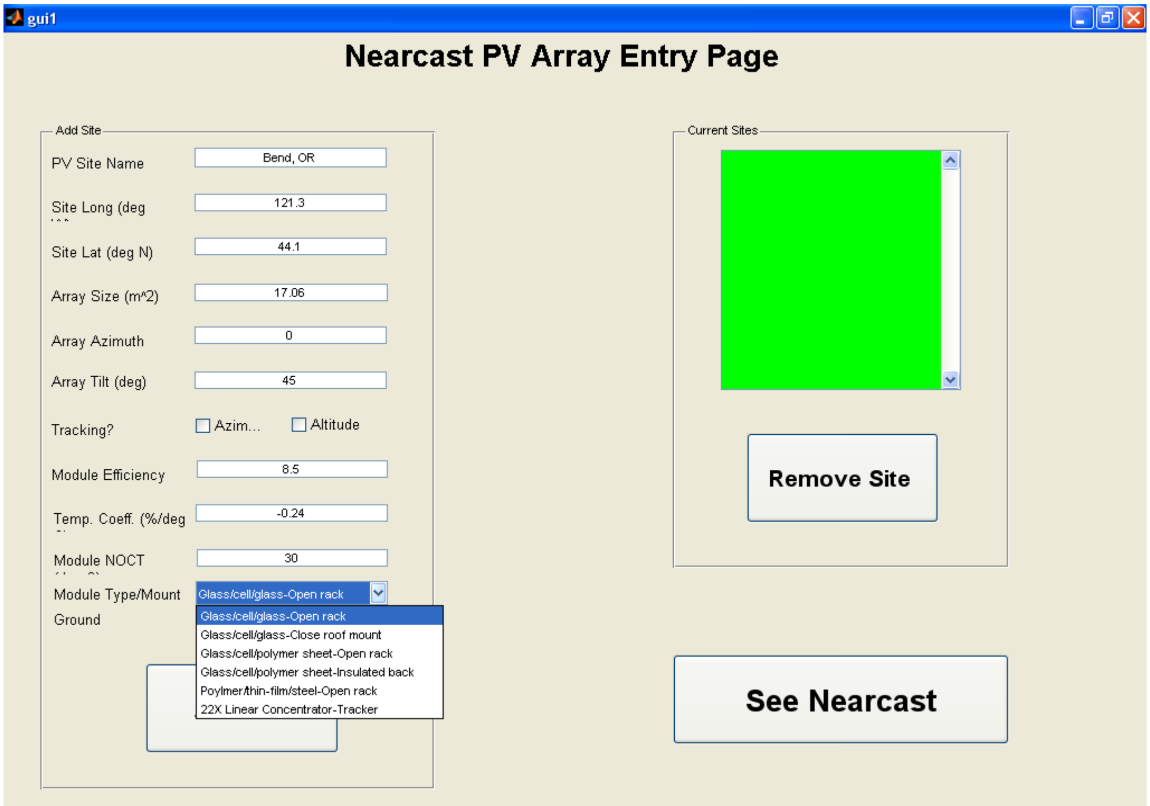

Figure 11. Nearcaster GUI, with the Module Type/Mount drop-down menu selections visible.

Clicking on the “See Nearcast” button in Figure 11 takes the user to the Nearcast Display Screen. The post-processor first checks the CRAS data to ascertain the latitude and longitude range covered by the data file. Once the geographical area covered by the nearcast data is established, the postprocessor checks each user-entered PV plant site and associates it with its nearest latitude/longitude point in the CRAS data. For each PV plant site, the post-processor then predicts the PV plant output at each nearcast time point.

Once the nearcaster has run, the Nearcast Display Screen shows the results. As shown in Figure 12, the left-hand pane shows either a contour plot or a 3-demensional plot of the irradiance at a specific user-selected time point (a snapshot in time over a space), and the right-hand screen displays a strip chart of the irradiance over time on the selected PV plant site (a snapshot in space over a period of time). In Figure 12, the results shown are for the Bend site for May 23, 2010. The blue square in the left-hand screen approximately indicates the boundaries of the state of Oregon, which is under overcast skies at the time point shown. (The left side of that left-hand pane is over the Pacific Ocean and is always shown in black.) The right-hand pane in Figure 12 can show global or plane-of-array irradiance, module temperature, or PV plant output power, as selected using the drop-down menu below the pane.

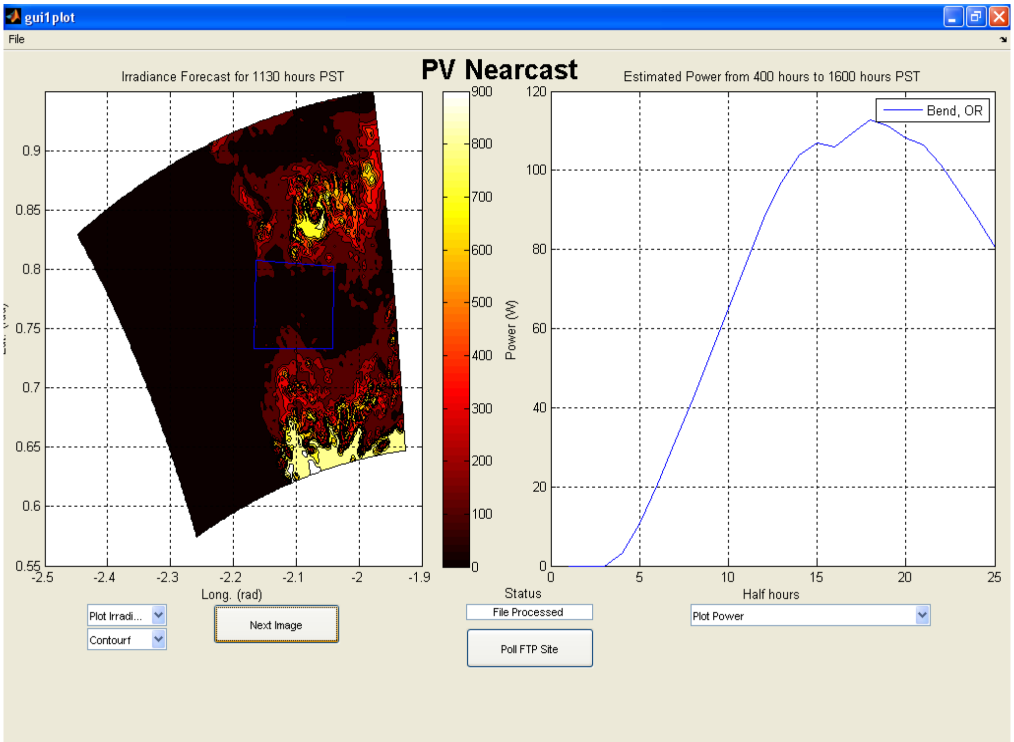

Figure 12. Nearcast display screen showing predictions for Bend, Oregon, May 23, 2010.

For the field trials, the team sought sites within the CRAS nearcast data footprint of the northwestern U.S. that included the following data (measured simultaneously):

- Global horizontal irradiance
- Plane-of-array irradiance
- Measured module temperature
- PV plant AC output
- All required information about the PV modules (usually manufacturer and model number, with which data sheets can be located)

One site was the PV Powered test site in Bend, Oregon, which provided many weeks of comparative data at one-second resolution.

Figure 13 and Figure 14 show global horizontal irradiance nearcasts for Arcata, California, and measurements from Humboldt State University. A clear day is shown in Figure 13, and the nearcaster qualitatively agrees with measurements; although, the irradiance is under predicted by about 10%. Figure 14 is interesting; it shows a case in which the nearcaster predicted afternoon clouds but the measurements show clear skies. Apparently, based on satellite photos and on-site observations, what happened is that afternoon clouds did develop but just missed the Arcata site; they slid north of the measurement station. Note that the late-afternoon (4pm) nearcast detected this change in conditions and is much more accurate, which suggests that if the nearcast update rate were increased, the overall accuracy would be much better than suggested by Figure 14.

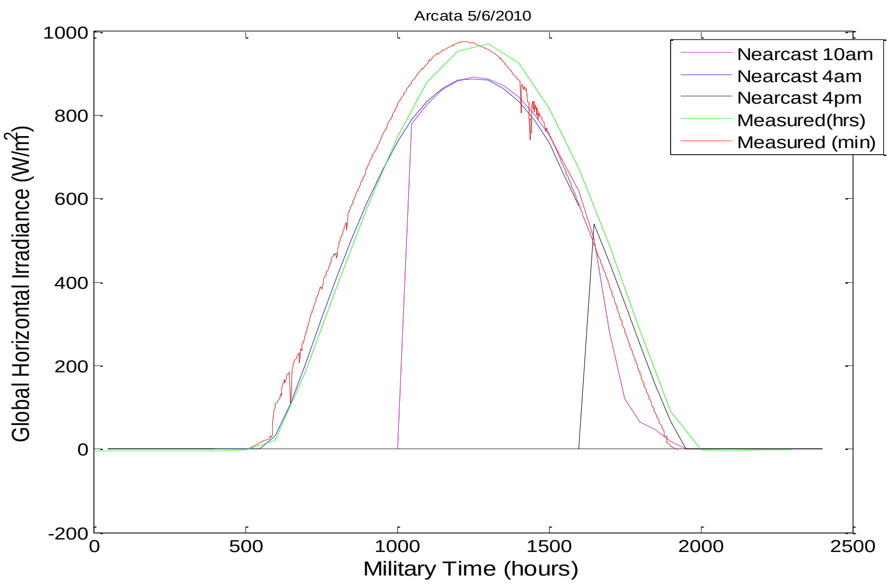

Figure 13. Global horizontal irradiance nearcasts and measurements: Arcata, California (clear day).

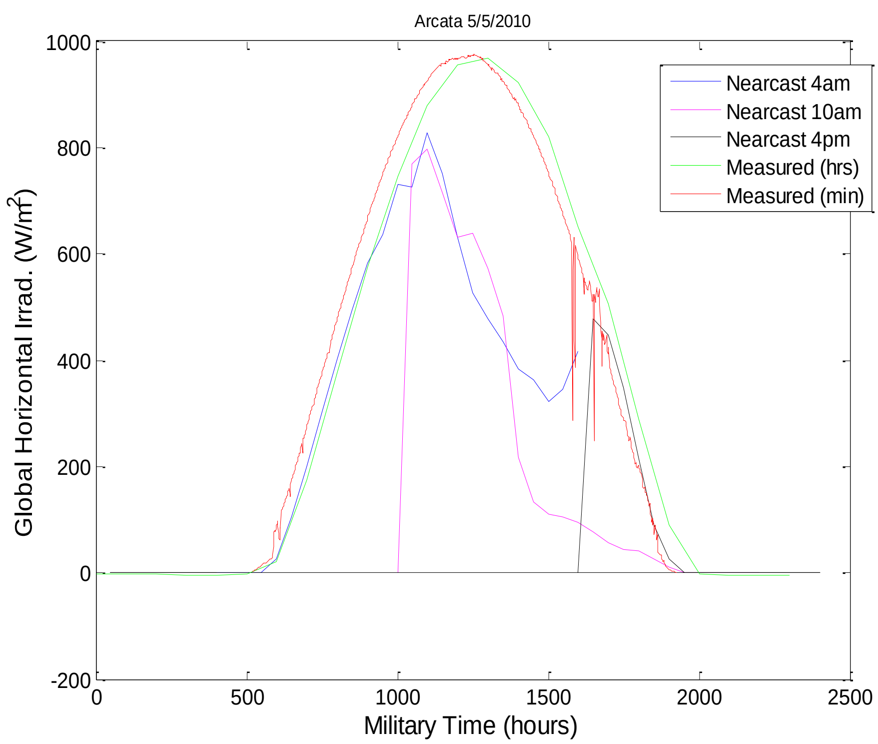

Figure 14. Global horizontal irradiance nearcasts and measurements: Arcata, California, on a day that turned out clear but was predicted to be partly cloudy.

Figure 15 and Figure 16 show nearcasts and measurements of the global horizontal irradiance, global plane-of-array irradiance, and module temperature for May 12 on the PV Powered test site in Bend. The measured data show the day to be mostly clear in the morning with scattered afternoon clouds. This is expected to be one of the most difficult cases to nearcast. In Figure 15, the first nearcast (10 pm local time) correctly predicts clear skies in the morning and appears to predict the development of clouds in the mid-morning, as evidenced by the drop off in the very last data point. The second nearcast (4 am local time) appears to follow this trend, predicting the formation of midmorning clouds. The last nearcast (10 am local time) detects that the morning clouds did not form and then predicts clear skies, which agrees well with the measurements for the first three hours or so, but then misses the formation of the afternoon clouds. As one might intuitively expect, the nearcaster does seem to succeed in "correcting" itself when conditions do not match nearcasts. Because the updates are so far apart, there is too much reliance on the older parts of the nearcasts where predictive accuracy is not as good.

In Figure 16, the global plane-of-array irradiance is under predicted as well, but it appears that most (although not all) of this under prediction comes from the original under prediction in the global horizontal nearcast. There appears to be a small additional under prediction occurring in the translation between horizontal and plane-of-array irradiances, attributed at this time to the use of an isotropic diffuse irradiance model. The isotropic model neglects the impacts of the circumsolar and near-horizon regions, which are brighter than the sky dome, and thus the isotropic model is well known to under predict the available diffuse irradiance.

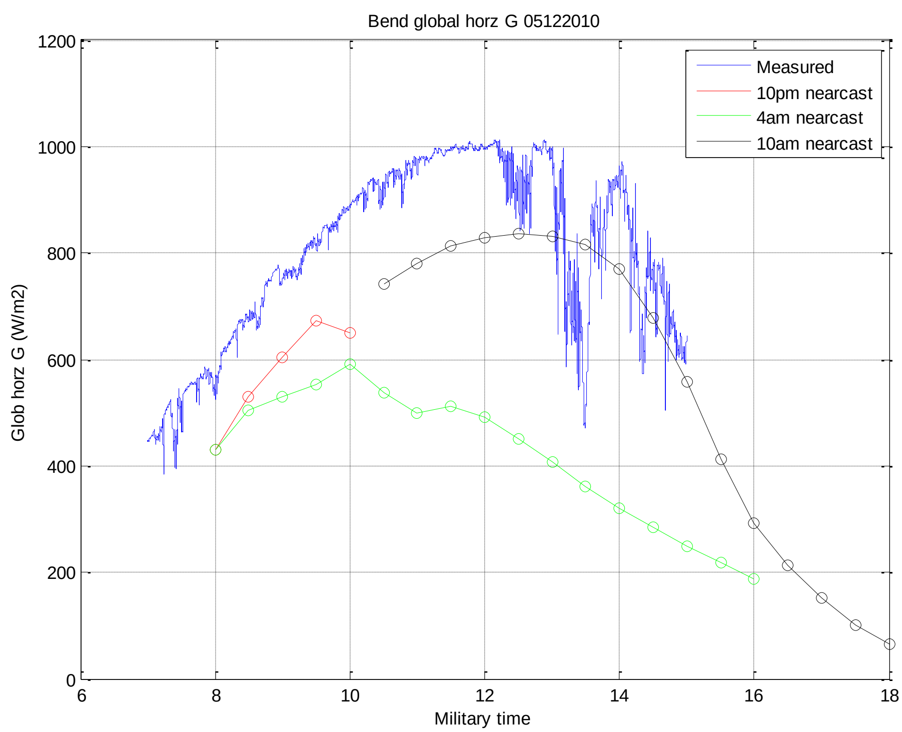

Figure 15. Global horizontal irradiance nearcasts and measurements: Bend, Oregon (clear day with a few afternoon clouds).

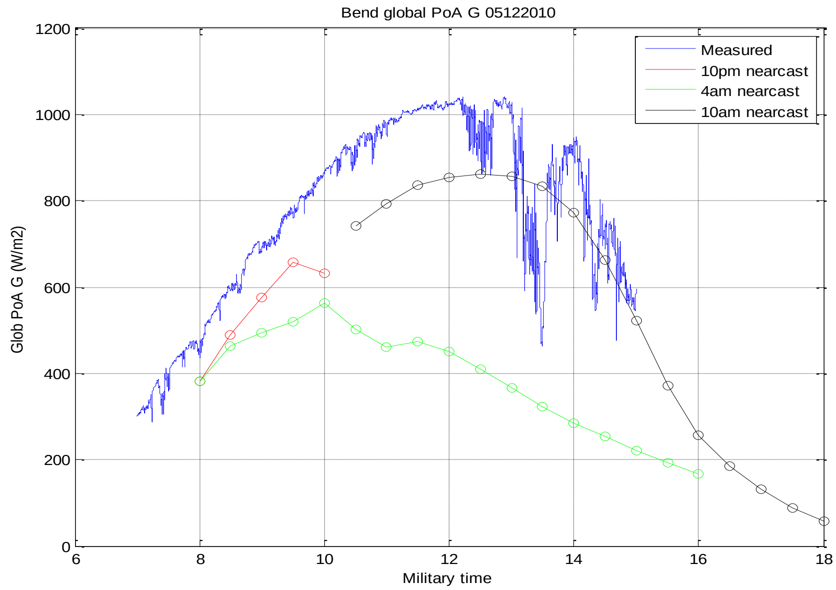

Figure 16. Global plane-of-array irradiance nearcasts and measurements: Bend, Oregon (clear day with a few afternoon clouds).

In summary, prototype testing results were promising and clearly illustrate both the potential and the challenges of this technology. The team concluded that the nearcaster can be successful, and that additional development and engineering work are warranted.

4.5 Utility Control Functionality

Under this task, the AE-led SEGIS team developed and commercialized a set of controls that allow for the inverter system to be controlled much like a traditional synchronous generator. As PV penetration rates continued to climb with clustering of installations in certain geographic regions, customers as well as utilities began pushing for more functional behaviors from inverter-based systems to alleviate concerns of voltage stability as well as power quality impacts. At the top of the list of functions was the capability to control the PF of the inverter to allow for sourcing and sinking of Volt-Ampere reactive power. As an electronic-based power device, inverters inherently have the capability to quickly change the shape of their respective output current waveform, hence providing the necessary VArs to the utility at will. Other functions demanded by the industry included curtailment (active power throttling), ramp rate control (ability to transition from one setting to another at a deterministic rate), randomization (to allow for smearing of effects across a multiple inverter installation), and remote enable and disable. The team implemented each of these functions throughout the SEGIS award period, commercializing them in all PV Powered brand commercial products.

4.5.1 Integration Methods

The manner in which the functions described above are controlled may differ greatly depending on installations size, installation owner, interconnection requirements, and other factors. As such, the team developed a set of solutions for controlling the governing utility command and controls package to meet the needs of the system owner (whether it be a utility or end user) while mindfully addressing any cost implications. The end result is the capability to control the inverters using any of the three below-listed techniques:

- SCADA direct control
- Building EMS control
- Stand-alone control (scheduler)

The first two techniques work much like any device that is controlled using a SCADA system. The governing controller (master controller) sends commands out to the inverters, effectively communicating set points for PF, ramp rate, curtailment, etc., and the PV system responds by transitioning to the newest (most recent) command. For closed-loop systems and large systems, this is a cost-effective manner to control the solar PV output (SCADA connected). Smaller systems also require the need for these advanced control features while cost pressures do not allow for SCADA solutions to be developed to meet the need of the interconnect requirements. The team recognized this as a barrier to high penetration of PV and developed an internal scheduler (inside the system secondary controller) to allow for the inverter systems to be pre-programmed with a governing PF, curtailment, and ramp rate schedule that effectively transitions the PV system to the required set-points at deterministic times of the day, week, month, and corresponding year. By including this scheduling capability internal to the inverter system, the team was able to significantly reduce system installation costs where interconnection requirements called for functionality to transition the generator (PV inverter) output at different times of the day, week, and month of the corresponding year.

4.5.2 Demonstration of Functionality

The team demonstrated throughout the course of the SEGIS program all the functionality listed above under all controlling methodologies (SCADA connected, BEMS connected, and standalone). For the SCADA connected demonstration, the team leveraged PGE's GenOnSys distributed generation SCADA controller to control the inverters output PF, power, and associated ramp rates. This functionality was demonstrated at the Demonstration Site Conference in Portland, Oregon, at the conclusion of the Stage 3 award. Further, the team demonstrated the capabilities of Building Energy Management System Controllers to modify inverter operation through multiple platforms (Tridium, Echelon, Johnson Controls, etc.) at the conclusion of Stage 2. Lastly, the team showed standalone (scheduled) operation on multiple inverters installed at an east coast location operating according to the interconnect schedule with no external controller. As a sample, Table 2 shows a schedule for PF that has been in operation on a number of PV Powered brand AE 260 kVA inverters installed at an east coast installation since April 2011.

Table 2. Power Factor Schedule

Month(s)	Start Time	End Time	Power Factor
Jan./Feb.	10:00 am	2:59 pm	0.98
	3:00 pm	9:59 am	0.99
March	10:00 am	10:59 am	0.98
	11:00 am	2:59 pm	0.97
	3:00 pm	4:59 pm	0.98
	5:00 pm	9:59 am	0.99
Apr./May/June/Jul.	9:00 am	9:59 am	0.98
	10:00 am	3:59 pm	0.97
	4:00 pm	4:59 pm	0.98
	5:00 pm	8:59 am	0.99
August	9:00 am	10:59 am	0.98
	11:00 am	3:59 pm	0.97
	4:00 pm	4:59 pm	0.98
	5:00 pm	8:59 am	0.99
September	10:00 am	10:59 am	0.98
	11:00 am	2:59 pm	0.97
	3:00 pm	3:59 pm	0.98
	4:00 pm	9:59 am	0.99
October	10:00 am	10:59 am	0.98
	11:00 am	1:59 pm	0.97
	3:00 pm	3:59 pm	0.98
	4:00 pm	9:59 am	0.99
November	9:00 am	1:59 pm	0.98
	2:00 pm	8:59 am	0.99
December	10:00 am	1:59 pm	0.98
	2:00 pm	9:59 am	0.99

The corresponding system responses met the functional targets of the interconnection agreement in addition to providing the functionality without increasing system costs. A sample of a single-day inverter response is shown in Figure 17.

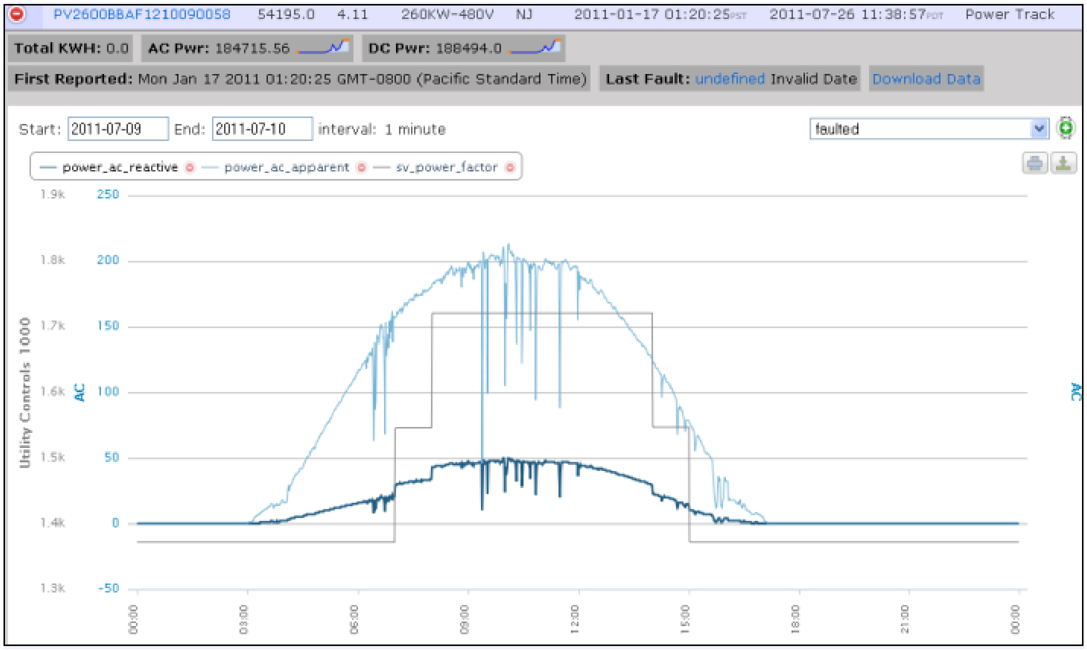

Figure 17. Inverter response to scheduled power factor.

Figure 17 shows the output kVA from a single inverter as well as the associated VAr output for the scheduled PF for a day in July (see above schedule Table 2). The system response transitions to the requested values precisely at the times required to satisfy the interconnection agreement with the local utility. As a final example, Figure 18 shows a schedule transition from the last day in July to the first day in August. Note that the PF schedule requirements change in the month of August to maintain the 0.98 PF for an extra hour in the morning.

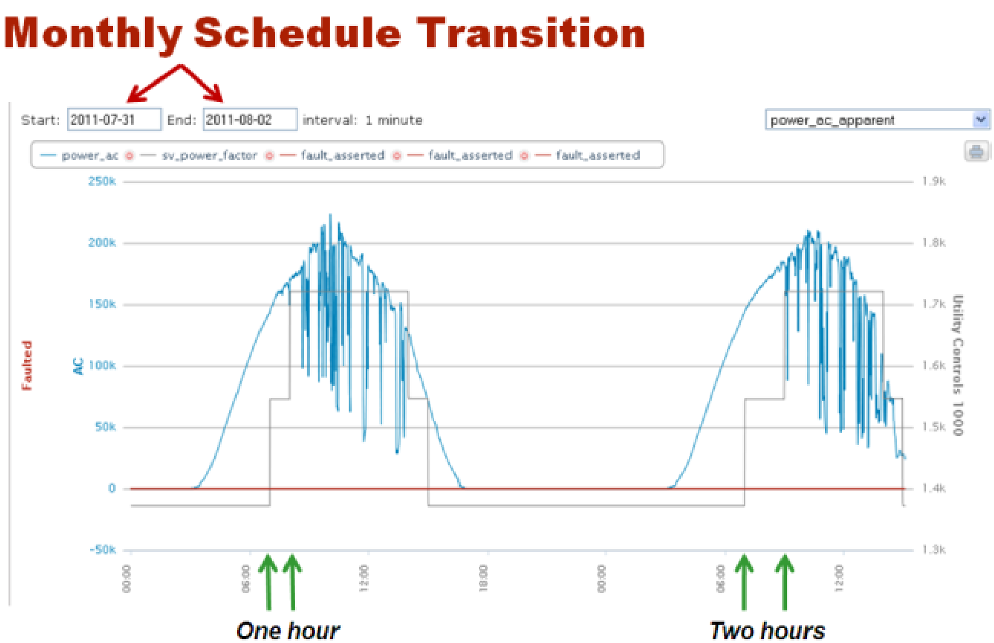

Figure 18. Transition of power factor schedule over month boundary.

This autonomous schedule capability developed throughout the SEGIS program award period is now shipping in all PV Powered brand commercial products to allow for seamless integration of PV systems even under aggressive interconnection requirements. As a solution for a range of system applications, the team is confident that this developed functionality will assist in lowering barriers to high-penetration PV while driving PV system costs toward grid parity.

4.6 Synchrophasor-Based Island Detection

4.6.1 Overview of Techniques

Throughout the course of the SEGIS development effort, the team created two separate synchrophasor-based island-detection schemes. At the conclusion of the program, each of these island-detection techniques were tested and proven to work on live systems; although, meeting the timing criteria outlined in the IEEE 1547 testing sequence proved difficult under certain circumstances.

1. The first scheme (Wide Area Network –WAN) is based on the fundamental slip and acceleration of the difference in the remote and local frequencies.
2. The second scheme (Pearson’s Method –CCB) is based on a statistical approach using Pearson’s equation for correlation.

For each developed technique, the fundamental island-detection algorithm requires both local and remote synchrophasor measurement units (PMU) data. To accomplish this, the team showed a communication channel agnostic approach, using fiber, Ethernet, 900 MHz radio, and wireless 3-G. The communication channels impact on the island-detection algorithm is response time, and has been proven not to compromise the detection itself (all island events are eventually detected).

4.6.2 Overview of Island Detection Algorithms

4.6.2.1 Wide Area Network Technique

This technique uses the difference in the local and remote voltage phases as a base quantity for calculation. Once determined, the first and second derivatives of this difference are calculated as slip and acceleration, respectively. The slip and acceleration are then used to determine if the inverter is connected to the local distribution network. Figure 19 shows a plot of a representative slip and acceleration band used to determine if a system is islanded.

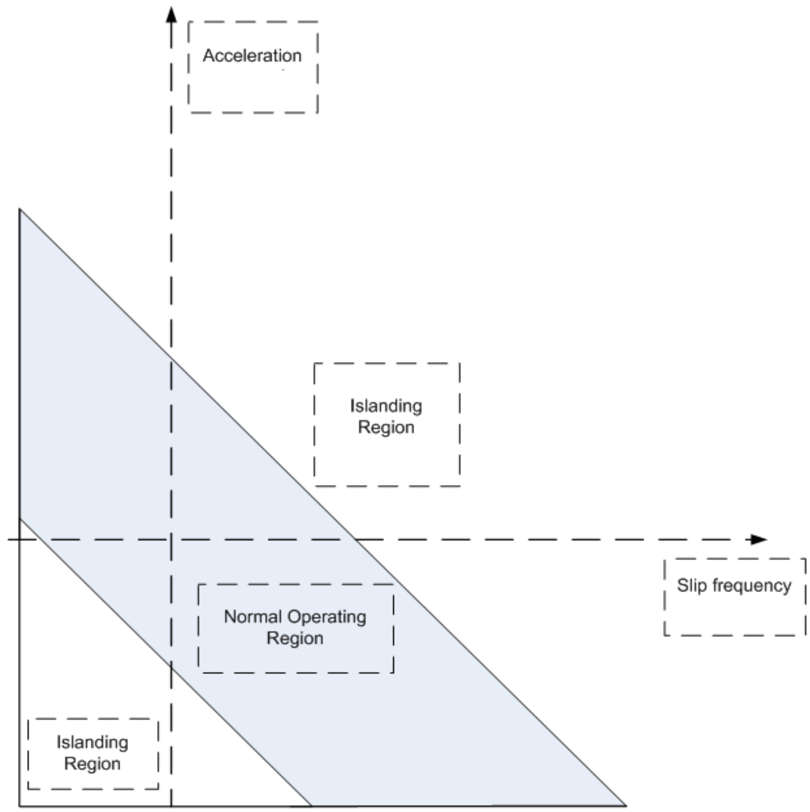

Figure 19. WAN based island detection.

If the slip or acceleration values pass beyond the governing limits set by the y = mx + b lines (outside the shaded region), the inverter disconnects from the local utility grid.

4.6.2.2 Correlation Coefficient-Based (CCB) Approach

The correlation coefficient-based (CCB) island-detection approach is based on the following equation (Pearson's Correlation):

$$r_P = \frac{\sum_{i=1}^{N}\left(x_i - \bar{x}\right)\left(y_i - \bar{y}\right)}{\sqrt{\sum_{j=1}^{N}\left(x_i - \bar{x}\right)^2}\sqrt{\sum_{k=1}^{N}\left(y_i - \bar{y}\right)^2}}$$

This statistical approach calculates a correlation factor (between 1 and -1) based on the local- and remote-measured frequencies. For a grid-connected inverter, the resultant correlation should be nearly 1.0; for an islanded inverter, the resultant correlation should be close to zero. The number of samples N is an important parameter for the tuning of this algorithm, and results for differing values will be shown below.

4.6.3 Simulation of Island Detection

The assembled team set out to prove that the phasor-based island detection would work at all points in the systems at all times. This is tough to prove in practice, so as part of the team's efforts, the team spent a great deal of time performing simulations to allow for rapid tuning, experimentation, and testing of the developed island-detection algorithms. The idea was to test the island detection not only for meeting current standards, but also for practical large high-penetration scenarios (multiple inverter installations, multiple inverter with synchronous generator included, large motor start cases, and the 2003 Italian blackout frequency case scaled to 60 Hz). For some of these cases, getting off the grid (disconnecting) is desired; however, for the large motor start and the scaled Italian blackout case, the desired result is for the inverter to continue to operate, offering the utility network increased support ("ride through"). For each simulated test case, results are shown for both the WAN and CCB island-detection techniques.

4.6.3.1 Case 1: Multiple Inverter Installation

For this simulated testing scenario, the IEEE Standard 34-bus distribution feeder was used as the example feeder. Eighteen PV inverters were connected to the feeder, one on each three-phase load bus, and simulations were performed to show that under high penetration scenarios with multiple inverters, the developed island-detection techniques would respond favorably. The island event occurs at t = 60 seconds on the plots, and each inverter shows slightly different results depending on their physical location on the feeder. A plot representing the response of all 18 inverters for the CCB method is shown as Figure 20.

The same multiple inverter case was simulated using the WAN methodology, and the response of the inverter system for the closest inverter to the feeder, as well as the farthest inverter is shown in Figure 21. Slip is the vertical (Y axis), and time is represented as the horizontal or (X axis). Figure 22 shows the same event on a 3-demensional plot, highlighting that at t = 60 seconds, the event is recognizable to the island-detection algorithm. The thrust of these figures is that for every inverter on the feeder, the island is reliably detected even in this high penetration simulation case.

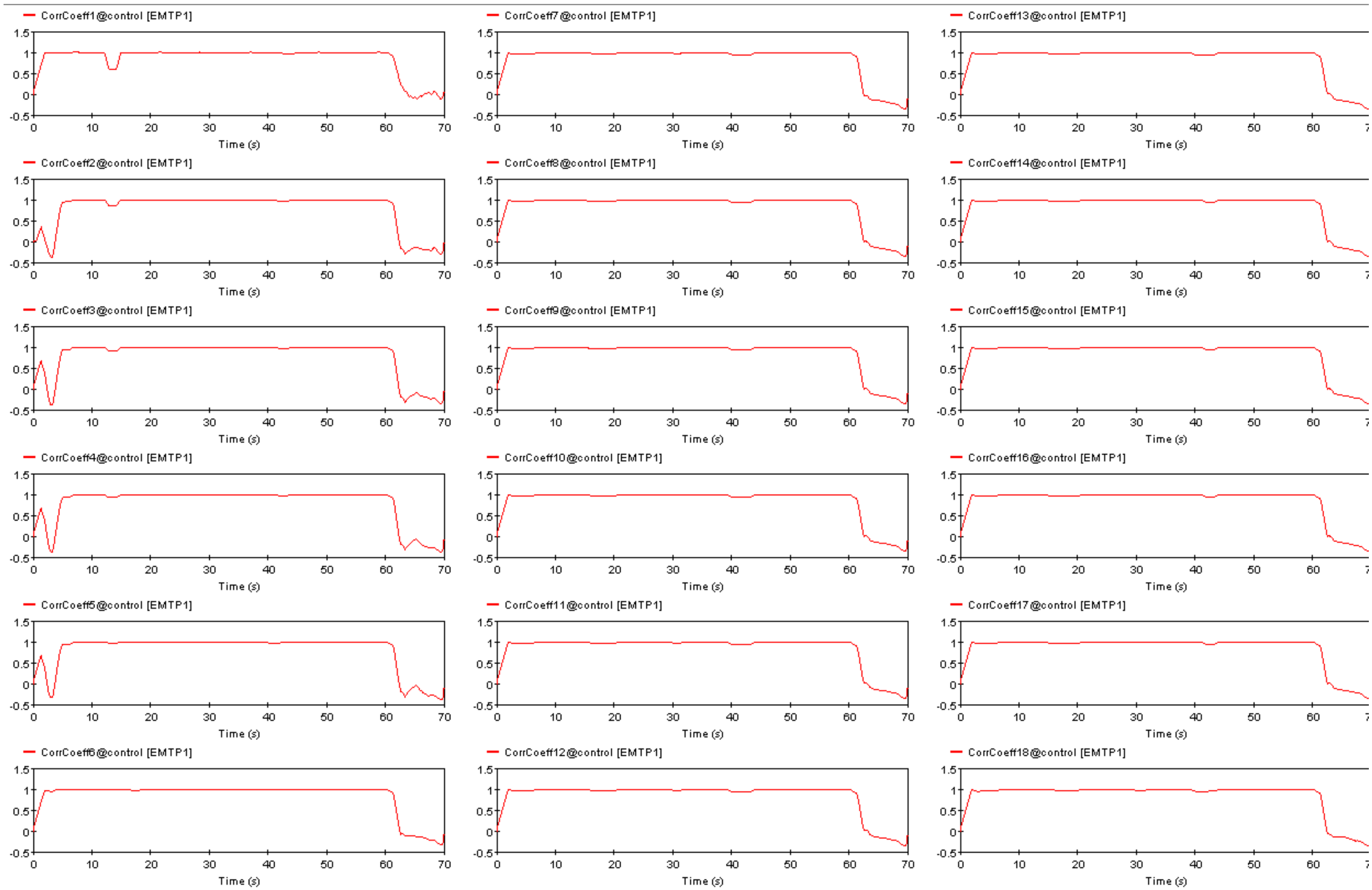

Figure 20. CCB island-detection algorithm with 18 inverters on IEEE Standard 34-bus distribution feeder.

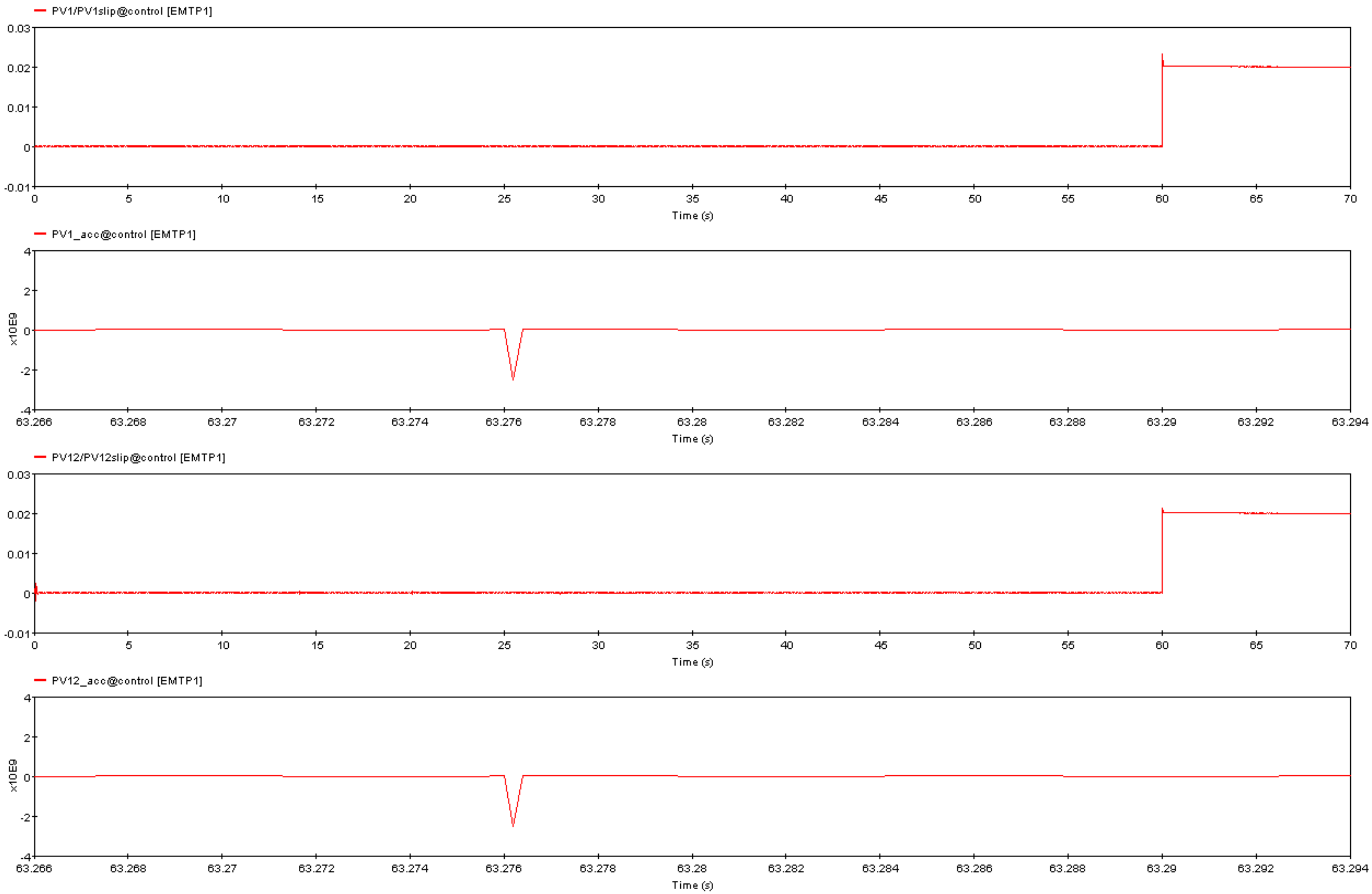

Figure 21. WAN multiple inverter connected to IEEE Standard 34-bus island event (top: closest inverter to feeder; bottom: farthest inverter from sub).

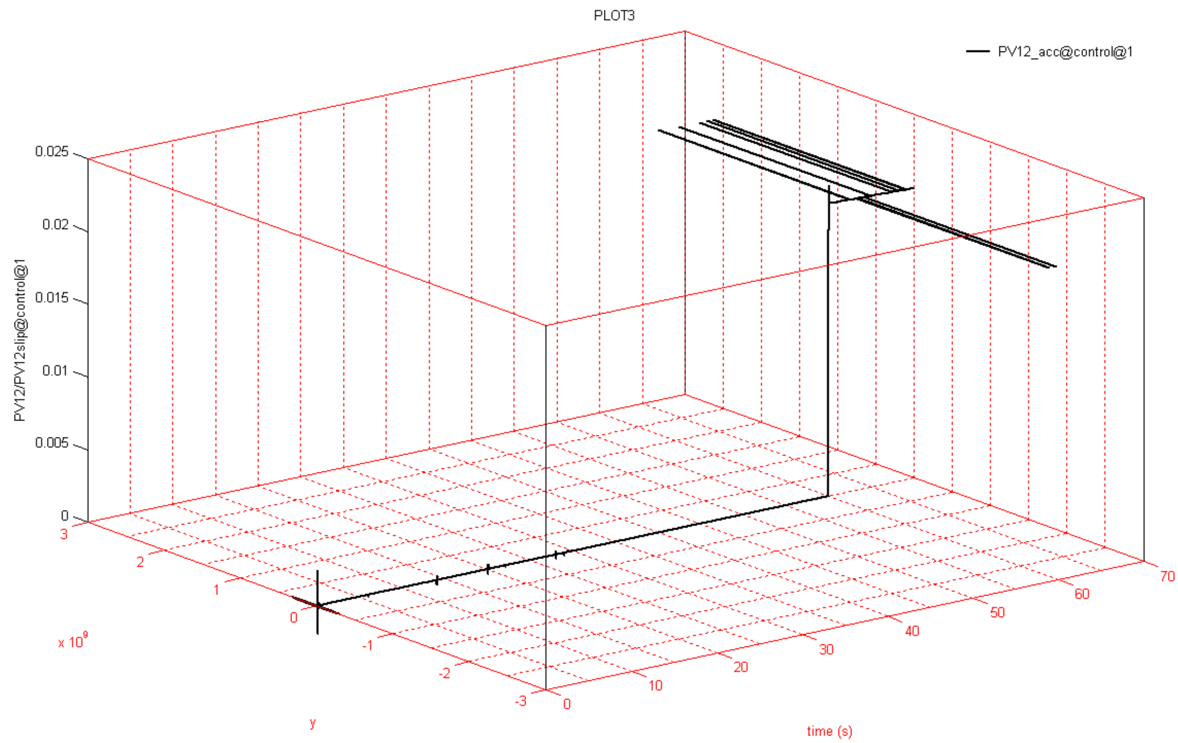

Figure 22. WAN island detection of one of the inverters for the multiple inverter connected to IEEE Standard 34-bus feeder.

4.6.3.2 Case 2: Multiple Inverter + Synchronous Generator

This case with multiple inverters and a synchronous generator is thought to be one of the most difficult situations for islanding detection. A 1 MVA diesel-driven synchronous generator was added to the feeder, and six of the inverters were removed to allow for generation-load matching. Again, simulations were run showing both the CCB and the WAN island-detection response. The responses to the synchronous generator and multiple inverter installation on the same feeder are shown in Figure 23 and Figure 24 (the deviations at the beginning portion of figures are due to the register for number of samples not yet being populated).

It is interesting to note that the inverters in Figure 23 do take longer to detect the island event with the large synchronous generator attached, but all inverters still reliably recognize the event.

Analyzing the response in Figure 24, it is difficult to determine if all of the inverters would recognize the island event with the WAN method coded alone. This response led the team to believe that for this case a slight perturbation (Sandia Frequency Shift – SFS) may need to be coupled with the WAN to reliably detect island events in a situation where many inverters are on the same feeder as a large synchronous generator.

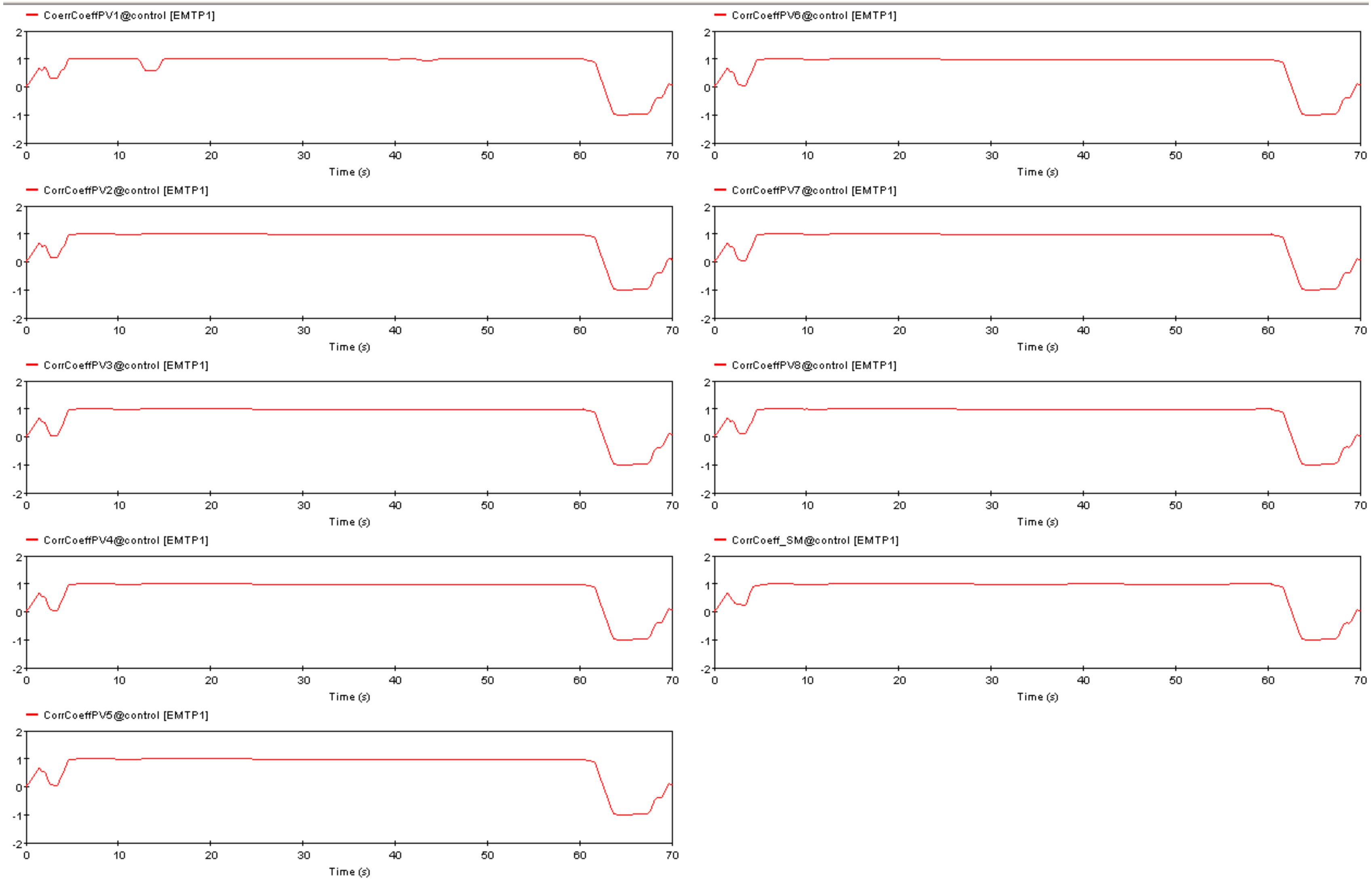

Figure 23. CCB method with large synchronous generator attached to IEEE Standard 34-bus distribution feeder.

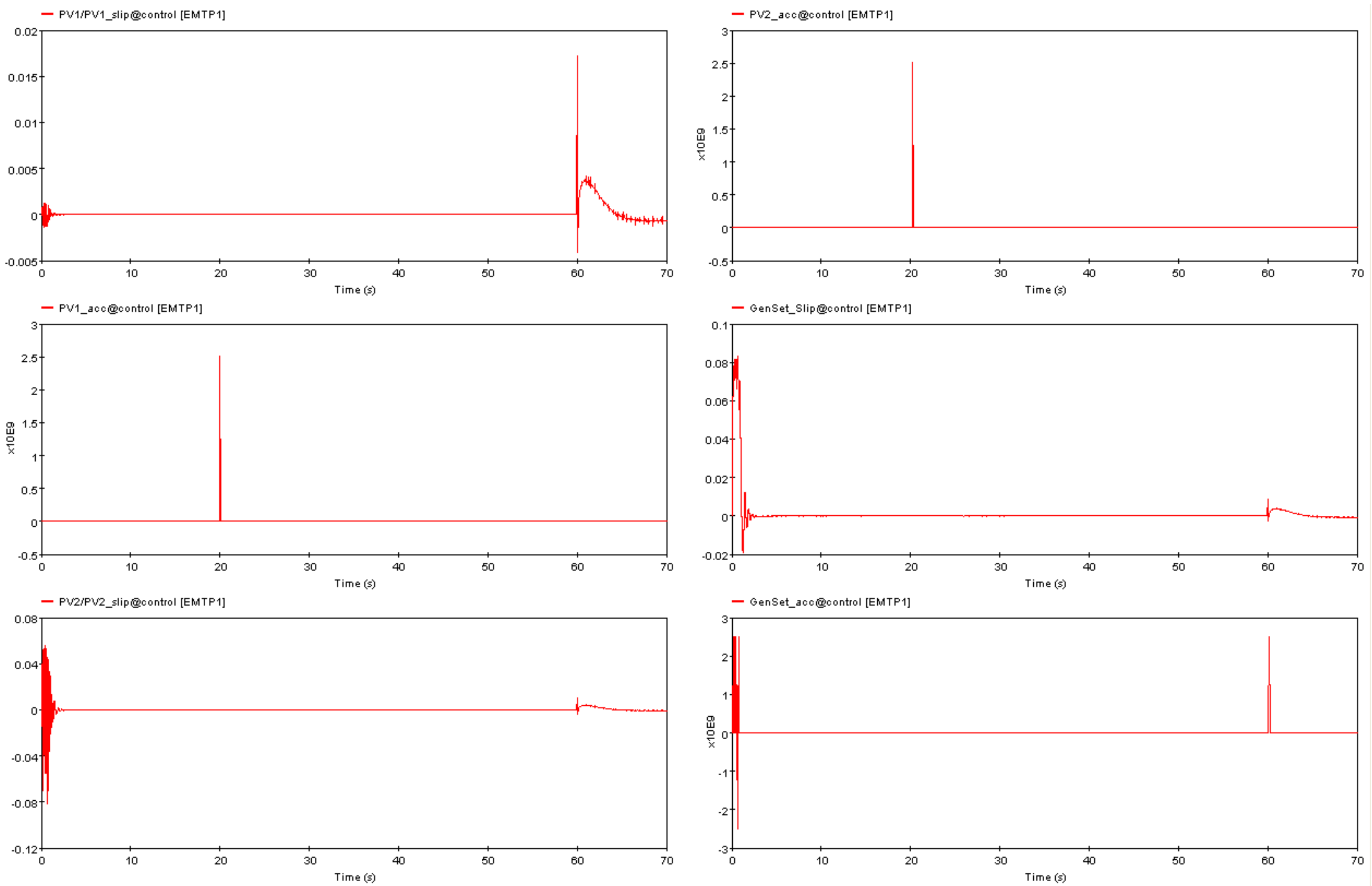

Figure 24. WAN response to the multiple inverter + synchronous generator island event.

4.6.3.3 Case 3: 2003 Italian Blackout

For this simulation case, the 2003 Italian blackout event was scaled to 60 Hz, representing an event where grid support (i.e., low-frequency ride through) from the inverters could have helped to prevent a cascading blackout. The team chose this event as a ride-through case as the data were readily available. The scaled frequency profile from the blackout event is shown as Figure 25.

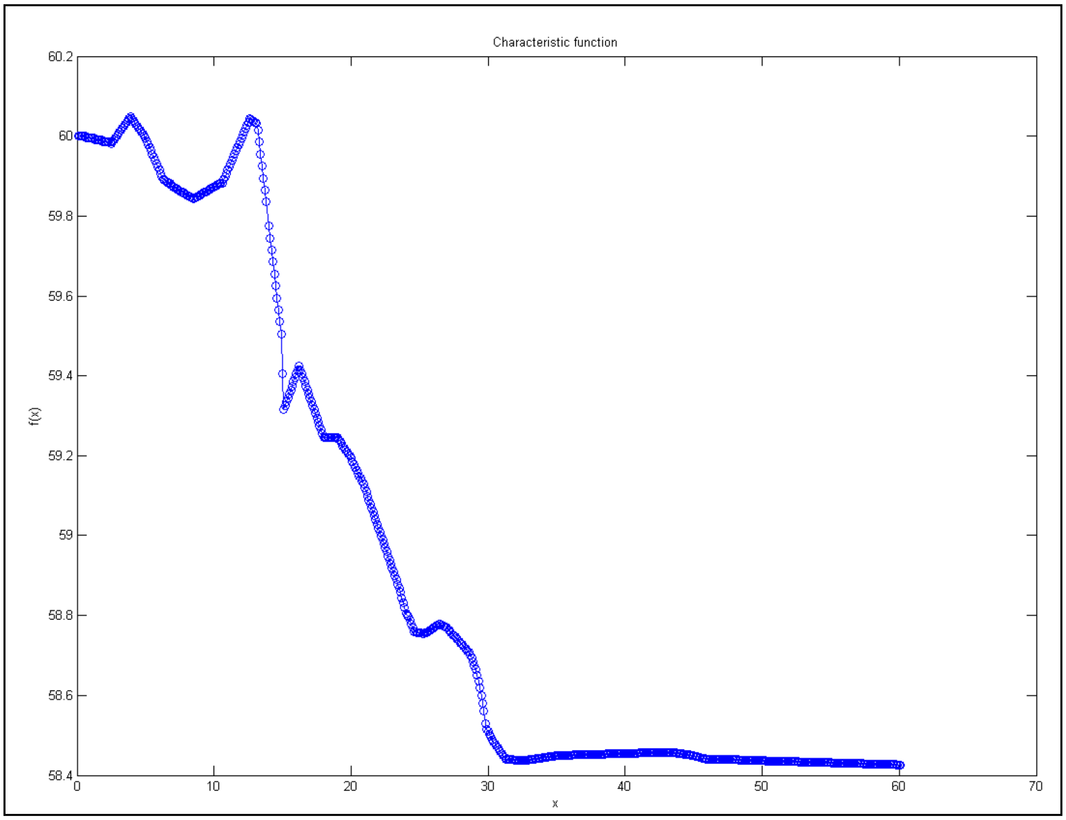

Figure 25. Scaled 2003 Italian frequency blackout profile.

This frequency profile was simulated with the multiple inverter installation on the IEEE Standard 34-bus distribution feeder, and the results for both the CCB as well as the WAN follow as Figure 26 and Figure 27, respectively.

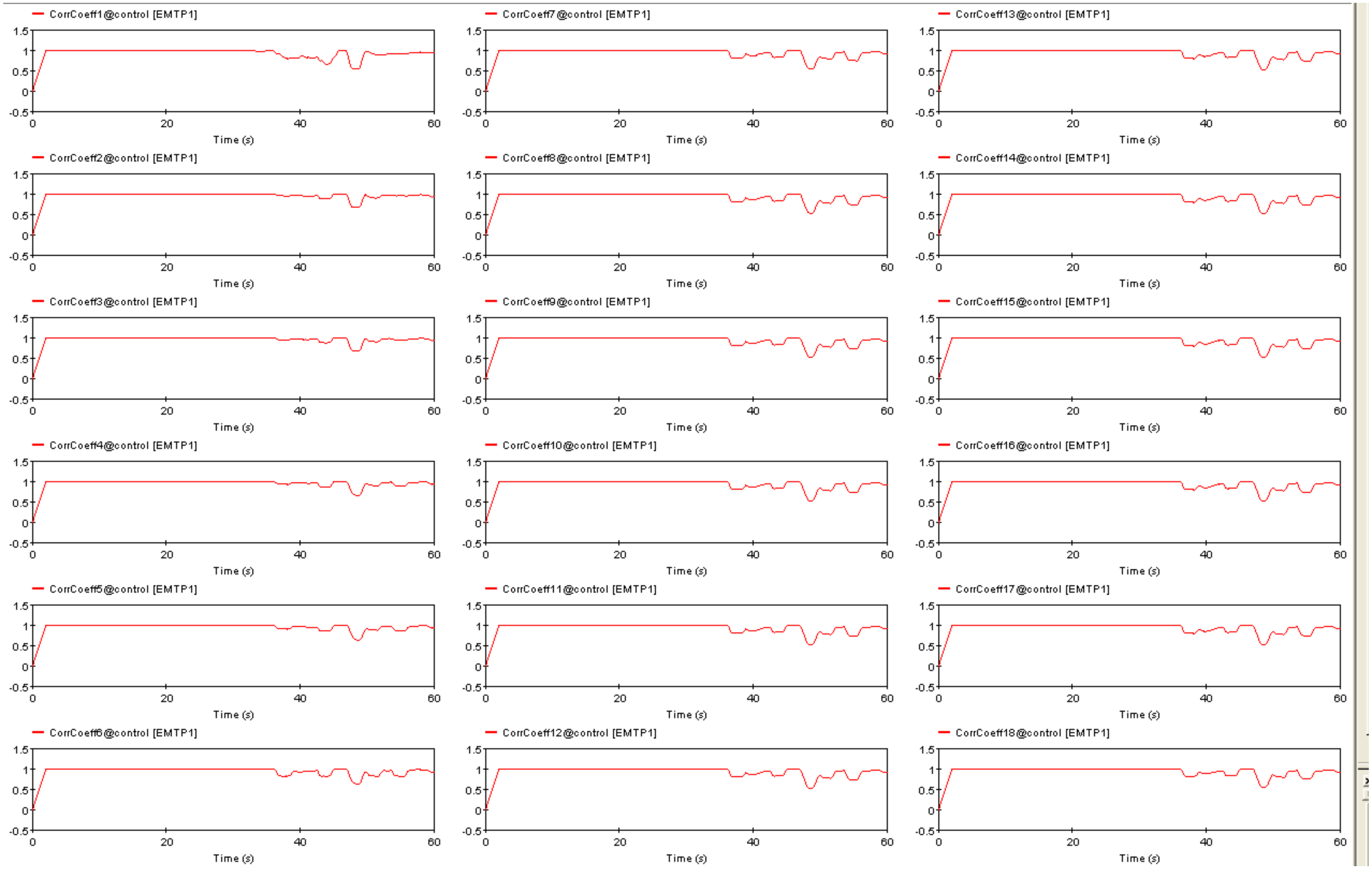

Figure 26. CCB response to Italian frequency blackout of 2003.

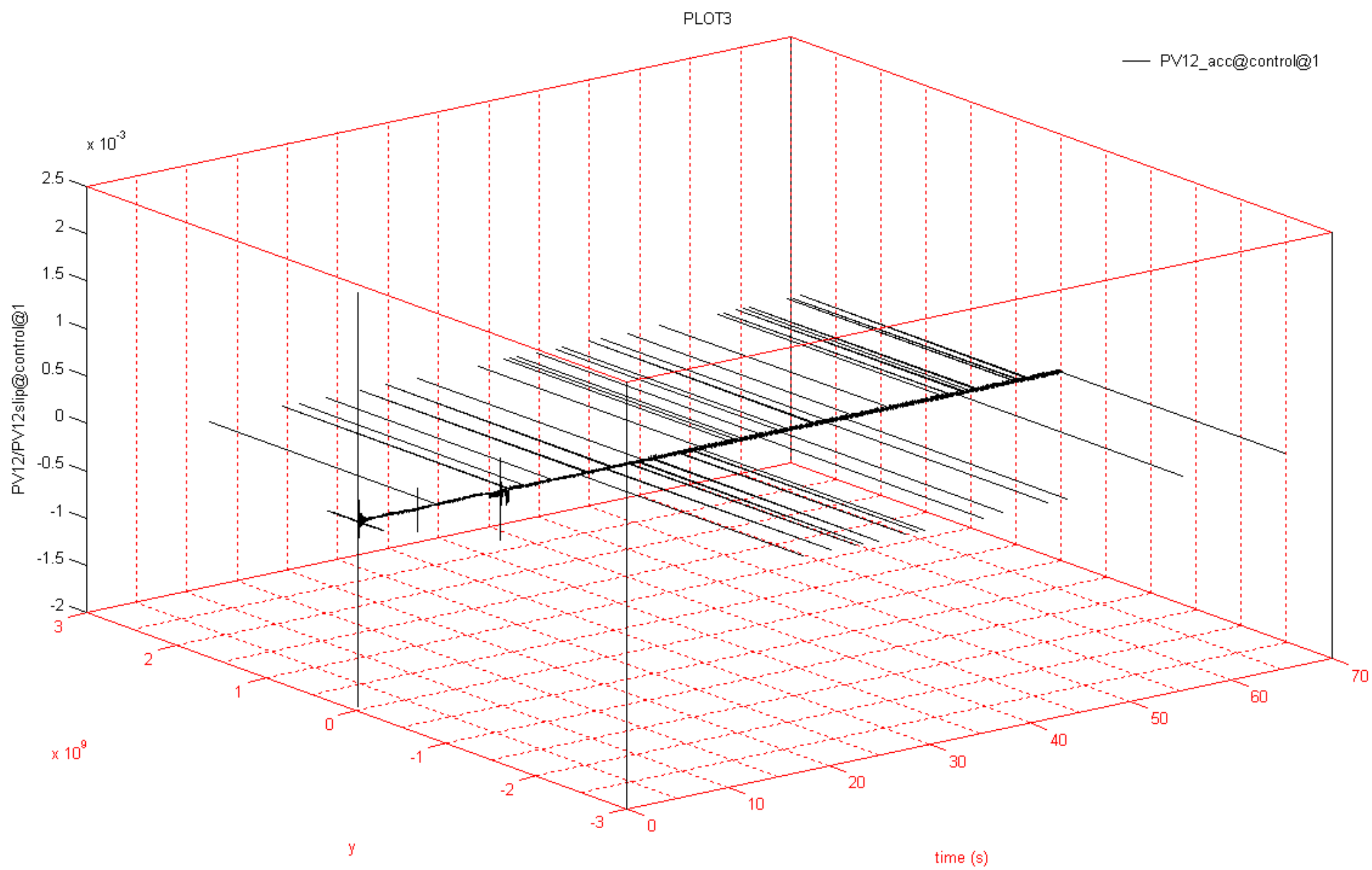

Figure 27. WAN Response of single inverter to the Italian frequency blackout of 2003.

Figure 26 and Figure 27 show that for the Italian frequency blackout case of 2003, both island-detection algorithms can provide ride through during the event, recognizing that the grid is still connected and that the inverters are not islanded (note: the axes scale represents the tuning thresholds associated with the slip and acceleration).

4.6.3.4 Case 4: Large Motor Start Event

For this testing case, a very large induction motor start was simulated in conjunction with a multiple inverter installation. The ideal response of the system is for the inverters to recognize the motor start but not trip offline. This particular event is one that limits how tight the thresholds for the island detection are set. These large motor-start events take place constantly on any given feeder across the U.S. and are one of the cases our team took very seriously when tuning the CCB and WAN algorithms. Depending on size and physical location of the bus, these events will still trip the new island-detection algorithms occasionally, and further work is being done to analyze performance versus safety tradeoffs for this case.

4.6.4 Field/Lab Testing of Island Detection Algorithms

In addition to the simulation work, the team spent a great deal of time in the lab and out in the field testing the algorithms on live equipment. Two separate mobile islanding test vehicles were developed that are capable of running 100 kW island events and 260 kW island events at a quality factor equal to three for full-load output. For each island-detection technique (CCB and WAN), tests were run for quality factors up to three for differing output power levels. The culmination of the field testing took place on Portland General Electric's distribution system: once at the Oregon Department of Transportation (ODOT) site, comprised of a 100 kW PV Powered inverter and 104 kW of available PV, and once at the Prologis site with a 260 kW inverter with 284 kW DC input. A mock-up diagram of the island test functional layout for the ODOT demonstration site is shown in Figure 28.

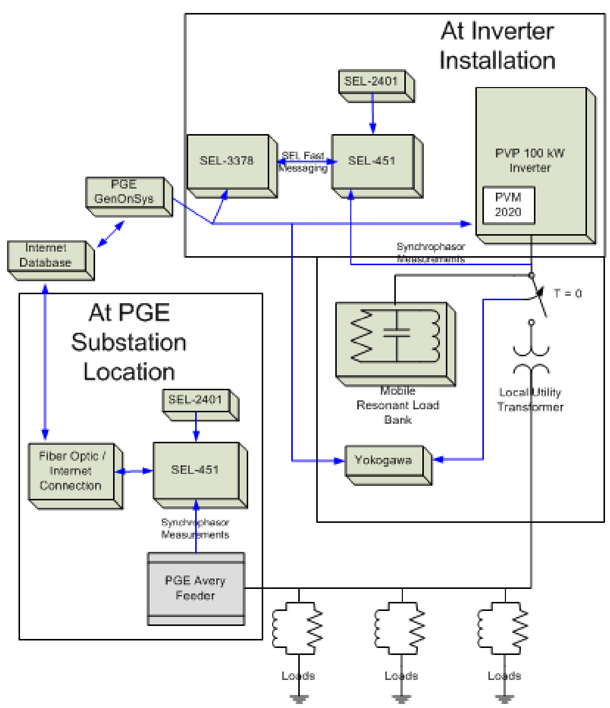

Figure 28. Functional layout for island testing at PGE's ODOT demonstration site.

As seen in Figure 28, the prototype for the demonstration in Portland used 2 SEL-451 relays: one at the demonstration site connected to the AC output at the terminals of the inverter and the second about 6 miles away at the Avery substation. The WAN algorithm was coded into a Schweitzer SEL-3378 vector program device for the purposes of demonstration, and reliably detected the island events tested for each case. During the witness evaluation test, quality factors up to three were tested with response times well within current IEEE 1547 limits. Post-processing of the witness evaluation test data shows that the correlation coefficient would also have reliably captured each of the island events (had we been using it for the Portland demonstrations); one such is shown as Figure 29.

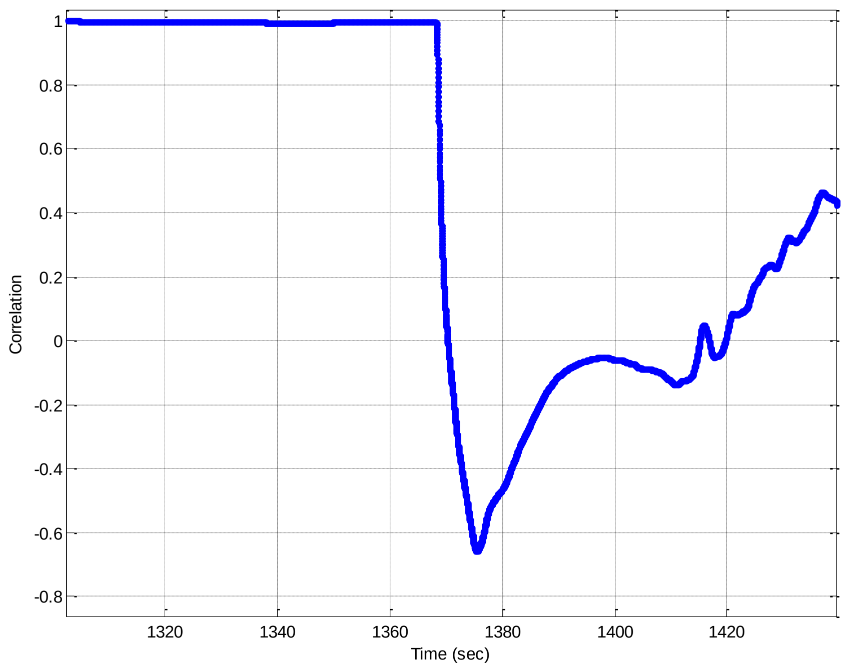

Figure 29. CCB response to witness evaluation demonstration island event (post-processed data)

The field and lab demonstrations for the island events with both the WAN and CCB island-detection techniques closely mirror the simulated results shown above. The team is confident in the ability for either algorithm to be commercialized and used as a reliable method for detecting island events while not adversely affecting power quality on the distribution feeders of electrical networks. The team is actively looking for ways to mimic the corner cases simulated above; however, some of these are difficult to accomplish either in the lab or in the field.

During Stage 3 of the SEGIS program, the team focused on developing the CCB island-detection algorithm as it showed promise to be low-cost, robust, and reliable in its operation even under very high Q levels with multiple inverters installed in a closely coupled scenario. Further, the computational needs associated with this choice were within the capability of the existing developed SEGIS hardware. As part of the demonstration process, the team coded the CCB algorithm into internal SEGIS-developed hardware and ran a number of demonstrations for the audience showing the promise of the synchrophasor-based islanding-detection technique.

4.7 Platform Integration

For this deliverable, results are broken into two sections: 1) secondary controller and associated hardware, and 2) SEGIS Database and API.

4.7.1 Secondary Controller

The objectives of this task are to develop a next-generation hardware platform for the aforementioned SEGIS deliverables as listed below.

1. Develop a secondary controller smart-grid communications and control hub with the following functions:
    - Modbus over RS485 and Ethernet.
    - Inverter controller communications and control.
    - Aggregate data from various data sources (e.g., inverter, weather station, smart string combiner, revenue meter, user interface).
    - Provide a long-term flexible platform, enabling broad future functionality.
    - Drive SEGIS user interface.
    - Run synchrophasor measurement island-detection algorithm.
    - Post data over Internet to SEGIS database.
    - React to solar PV plant controller inputs.

2. Develop a next-generation user interface integrated into the inverter capable of the following:
    - Diagnostics and data visualization.
    - Configuration of trip points.
    - Commissioning of balance of system components.
    - Configuration of advanced MPPT algorithm.

3. Revise the existing physical inverter platform to accommodate SEGIS components, including:
    - User interface.
    - Secondary controller.
    - Communications extension board providing connections for Ethernet, RS485, and other communications ports.
    - Phasor measurement unit and Global Positioning System (GPS) clock from Schweitzer Engineering.
    - Power-line communications bridge (bridges communications between DC bus and secondary controller).
    - Low-voltage wiring area isolated from high-voltage DC and AC components, enabling low-voltage technicians to connect communications gear.
    - UL 508A space in the low-voltage wiring area for custom systems integration.

The goal for integration of these components is to minimize any increase in cost over the baseline cost of the inverter.

4.7.1.1 Progress

The team set out with the primary priority to develop the secondary controller for two reasons: 1) it would be the primary platform for integration of all the other task components, and 2) the timeline was short and development of this controller was deemed the highest risk component of this task.

4.7.1.1.1 Secondary Controller

The team allocated resources to develop the secondary controller in parallel with one group focused on software development and the other group focused on development of the physical hardware. Below is a brief summary of the approach, effort, and key milestones associated with the development of the secondary controller.

Hardware

The secondary controller circuit board serves many functions. Being the communications hub of the inverter, it requires substantial computing power, storage, and peripheral interfaces. The hardware design approach was to develop a communications card that fits the form factor of the card cage designed into PV Powered’s existing commercial inverters. Figure 30 depicts the prototype secondary controller printed circuit board assembly (PCBA).

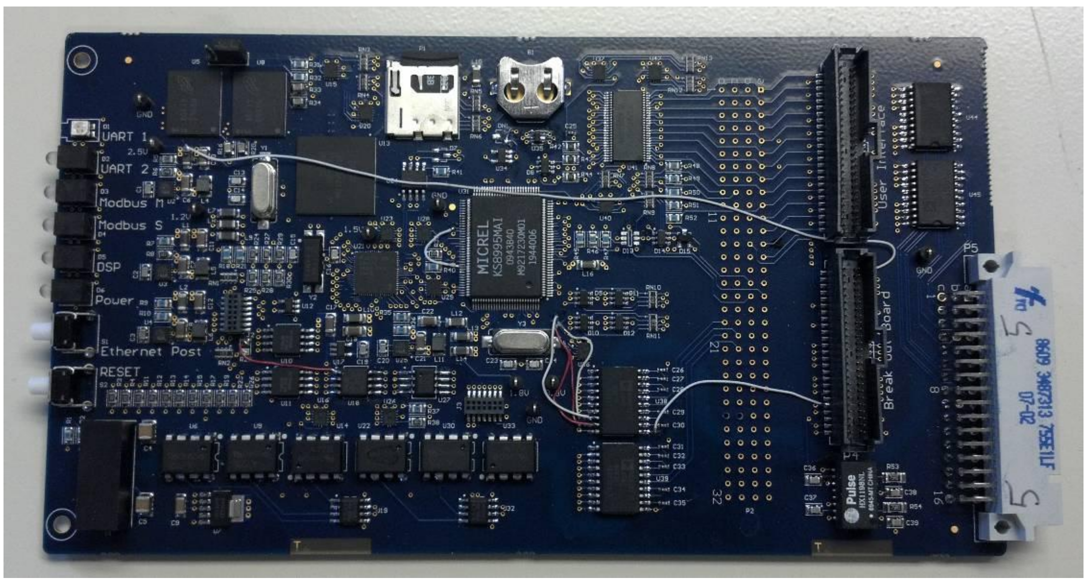

Figure 30. Secondary controller PCBA prototype.

Software

Early in the project, the team elected to run the Linux operating system on the secondary controller. This decision was based on the team’s earlier experience with proprietary operating systems and the lack of flexibility that they offered. Additionally, leveraging Linux enables a wide range of open- and closed-source software tools and packages.

To maximize team efficiency and minimize the potential for hardware design errors, the team, working in parallel, initiated work on the software platform design. Two development kits were purchased, and the software team learned how to build the Linux kernel and gained an understanding of the boot process and all of the peripheral interfaces. Invaluable learning occurred during this period that affected the hardware design. Key areas included allocation of proper Universal Asynchronous Receiver/Transmitter (UARTS) memory management and boot schemes, and selection and validation of total flash and random access memory (RAM) memory sizes.

The team also developed a first cut of the software functional architecture. As the architecture was discussed and refined, it became clear that the essence of the operation of the secondary controller is that of a large data store with many producers and consumers of data. This understanding led the team to think about how it might accomplish the central component of the software – the data store. The team chose an embedded database to accomplish this task.

Once the central data store was selected, the team refined the software architecture. After the software architecture was defined, the team developed a strategy and specifications for developing each software component. Some of the software could be ported from AE's existing secondary controller, but much of it required new development. Specifications were defined, and communications protocols were selected for synchrophasor communications and island detection. A new protocol was developed for smart string combiner communications. The team employed a strategy for development based the following priorities:

1. Get the platform running:
    - Get the board running once the hardware is in-house. A second resource was dedicated to this so that software application development could continue in parallel.
    - Get the central database configured and working; develop a database schema architecture.
    - Get the inverter communications and web post applications working as early as possible. This facilitates timely data flow from the inverter through the central database to the web post application and out to the SEGIS database. Each major component is validated and provides an opportunity for the SEGIS database team to validate their software.

2. Task integration:
    - Develop a synchrophasor application for island detection that pulls data in from remote and local PMUs, time aligns the data, calculates correlation coefficient, and determines whether the inverter is islanded or not.
    - Develop combiner program that parses combiner data from the serial port, translates it, and inserts it into the database.
    - Incorporate combiner and weather station posting capability into the web post application.
    - Develop a prototype user interface application.

4.7.1.1.2 User Interface

Given the challenges with getting the secondary controller running, overall workload, and task time allocated during the prototype stage, the team was considering the user interface as a low priority deliverable. However, electronics design resources were available, so the team forged ahead, identifying a high brightness, high reliability LCD display, and designing a user interface PCBA for the SEGIS prototype. In addition, mechanical design resources were identified for mechanical integration of the user interface into the inverter. Using a parallel development path approach, the team was able to get the user interface hardware debugged and functioning for prototype demonstration. Figure 31 depicts the user interface mechanical design.

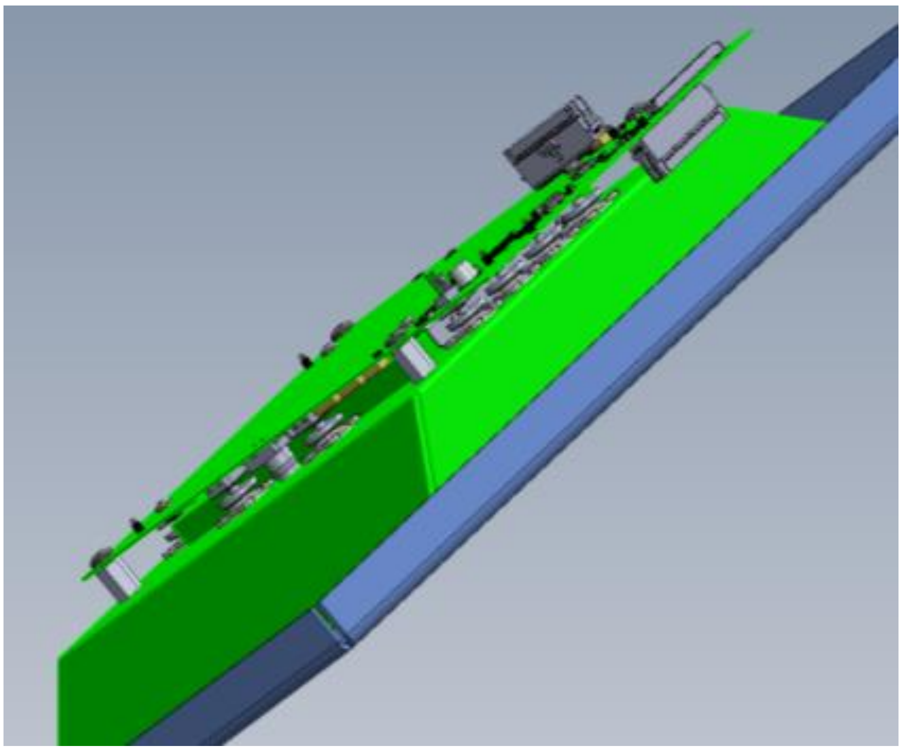

Figure 31. Solid model of user interface.

4.7.1.1.3 Physical Inverter Prototype

The team allocated an off-the-shelf PVP75kW inverter for integration of the prototype SEGIS task components and commissioning on the SEGIS array. The final step was to integrate the SEGIS components into the inverter. The following components were integrated into the prototype.

- Secondary controller and user interface.
- Combiner power line to serial communications bridge, powered from DC bus.
- Prototype line filter, enabling good signal-to-noise on power line communications,
- Schweitzer revenue meter/synchrophasor measurement unit and GPS clock,

Functionality of each component was demonstrated during the program. During the course of Stage 3, the team split efforts to ensure success of the most critical task components:

- To ensure the team could commercialize the highest TRL tasks in the program, the team chose to leverage existing secondary and primary controller platforms. This enabled timely commercialization of the new MPPT algorithm, communications with the SEGIS database, and commercialization of the most urgently needed utility interactive controls.
- The team continued development on the secondary controller platform. While considering a broader scope due to the acquisition of PV Powered by AE, the team evaluated the most prudent approach to the secondary controller platform with the goal of enabling *all* of the SEGIS developments on as many types of AE inverters as possible.

4.7.2 SEGIS Database and API

Below is a brief summary of the requirements developed for this product. The objective of this task was to develop a next-generation database system for SEGIS data, including advanced analytics, an API for external stakeholder access, and an internal reporting tool.

- Develop a new database for storage of SEGIS inverter system data. The database shall be architected as a real time database with long term historical storage and data analysis capabilities and shall store data from the following sources:
    - Inverter data
    - Advanced string combiner data
    - Weather station data
    - Revenue meter / synchrophasor data
    - MPPT parameter data
    - Weather nearcast data
- Develop an API for remote access to the data by 3rd parties such as utilities, financiers, system owners, and other entities.
- Develop an internal reporting and analysis front end to provide access to the data (Headlamp). The application should perform at least the following functions:
    - Device details report (including inverter, string combiner, weather station)
    - Inverter system availability report
    - Fault Pareto charts by device, and across device population

The goal for this task was to provide a home for all of the SEGIS data generated, and to provide a means for sharing these data across industry groups for various purposes ranging from smart-grid functions to meter reporting to operations and maintenance management.

4.7.2.1 Results

AE, being a hardware oriented company, significantly underestimated the cost and complexity of developing a true database monitoring system. Members of the team had some experience with databases, monitoring, and web applications, but the team did not sufficiently understand the complexity required for the envisioned system until a detailed design review was conducted with a prominent software design consulting company. A Critical Design Review was held in which the firm led the team through a series of discovery meetings where they distilled and translated our high-level requirements into software and database requirements. The net conclusion and outcome from the engagement was that the team had underestimated the cost and complexity of the project. It turns out that the amount of data required to be stored and real-time reporting requirements (e.g., the ability to see what a SEGIS inverter is doing with no more than a 15-minute lag time) creates a need for a complex database system.

The team chose a collaborative and adaptive (agile) approach to developing the database platform. Early in the project, the team developed a detailed development plan for the SEGIS database system.

The plan developed was comprised of four incremental stages:

1. Build a storage platform for SEGIS inverter data. Develop a simple API that allows for extraction of the inverter data. Develop internal web views for these data so that reliability, engineering, and customer-service teams can access these data.
2. Focus on adding storage capability for SEGIS solar PV plant data, specifically smart string combiner data, local weather data, and possibly synchrophasor data. Update the web service API to provide capability to get SEGIS data out.
3. Build a prototype data warehouse for the data. This data warehouse will provide capabilities for predictive analytics and powerful data processing so that key learning can be produced from the SEGIS data.
4. Test data warehouse and rollout to production.

The staged approach allowed for functioning prototypes at the conclusion of each stage. Completing the four stages was estimated to take 12-18 months.

4.7.2.1.1 Planning and Architecture

With the approach defined, the team set out working on Stage 1: building the storage platform for SEGIS data. The first step involved a week-long planning meeting where the team conducted a deep-dive to look at architecture tradeoffs and traditional relational databases versus so called schema-less databases. The team brought an expert PhD computer scientist in from the Massachusetts Institute of Technology (MIT) to provide input into this critical planning stage. The results of this series of meetings were:

1. Detailed project plan for Stage 1, including project schedule and selection of project-management tools and approach.
2. Extensive discussion and final agreement on remote monitoring system architecture.
3. Discussion and alignment on hosting architecture for Stage 1 and subsequent stages.
4. Definition of reporting requirements for Stage 1.

Figure 32 illustrates a simplified view of the SEGIS database architecture and dataflow.

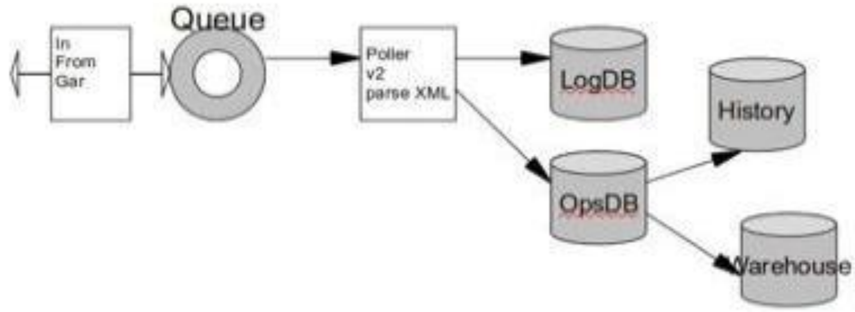

Figure 32. SEGIS database architecture

The team agreed on a data-warehousing architecture with all raw data being stored in a log database first. The purpose of the log database is to store all raw data in a relatively unstructured manner, providing the flexibility to rebuild all other databases from the log database. After the log database, the operational database was designed. The purpose of the operational database is to provide real-time access to all recent system data. This strategy keeps the operational database relatively small and manageable, providing good real-time performance. The historical database was designed to store long-term data. The purpose of these databases respectively is for storage and retrieval of long-term historical data, and in the case of the data warehouse, to bring data in from additional sources and to modify the structure of the data to accommodate predictive analytics and data analysis in general.

4.7.2.1.2 Prototype Construction

The first focus was on building the log database and the ability to get data into the log database. Getting a solid log database done early provided a foundation for all the other tasks and provided a place to store inverter data immediately, enhancing the team's ability to build and debug the remainder of the system.

Once data were reliably flowing into the log database, the team focused on the operational database design. Significant time was taken designing a flexible operational database. Where the log database had on the order of 5 tables, the operational database has on the order of 25 tables with many more complex interdependencies (areas that seem simple are not always simple for database design). The team worked through the challenges one at a time.

After significant effort getting the operational database designed and data flowing into the database, the team began validating the data in the database and working on the internal reporting tool coined Headlamp. This tool would be used to demonstrate SEGIS deliverables. Once the application framework was in place, it became a matter of testing, reviewing, and refining. The team continued to meet and design in additional features.

4.7.2.1.3 Prototype Validation and Demonstration

Figure 33 shows sample snapshots of the Headlamp application, illustrating the state of the prototype at the conclusion of the prototype stage of the program. Both inverter data as well as smart string combiner data were integrated and demonstrated on the user interface. Headlamp was also used to demonstrate operation of the smart string combiner developed during the SEGIS program.

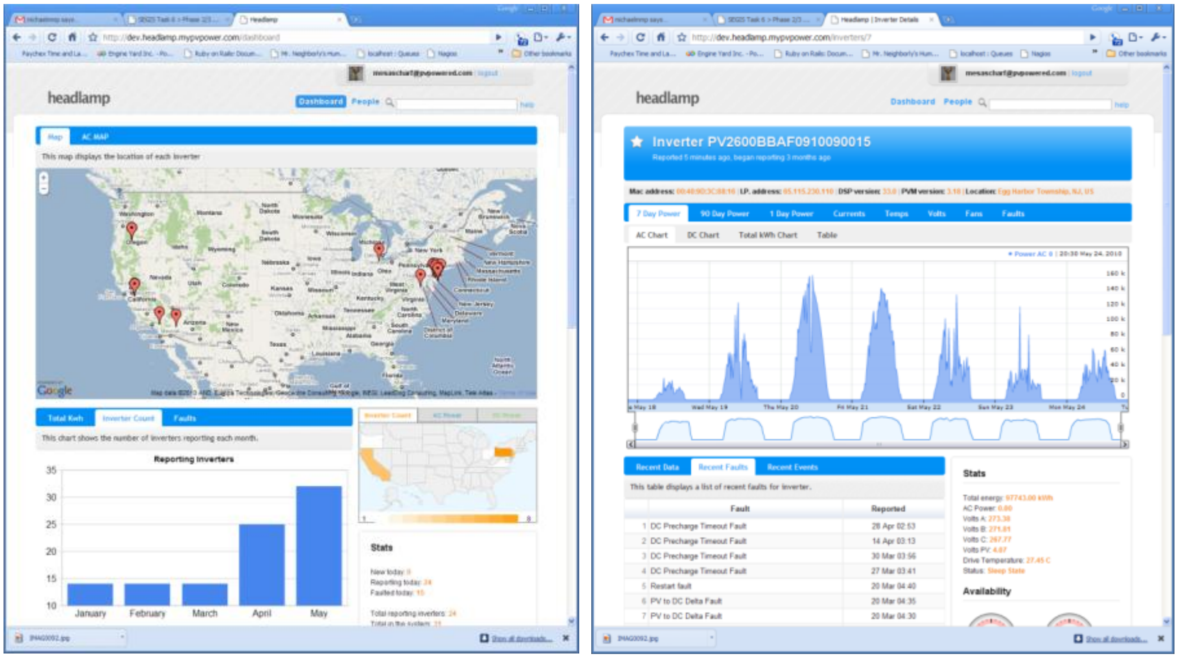

Figure 33. Sample snapshots from Headlamp application.

4.7.2.2 Commercialization

During the commercialization stage, the team continued work on the database platform, the Headlamp application, and APIs. Focus shifted largely to the APIs, enabling a service-oriented architecture where any cloud-based application could access the APIs and pull PV energy system data in for various purposes. Headlamp was further refined for service and reliability purposes, based upon lessons learned from Stage 2, that resulted in architectural changes to yield greater platform flexibility. Further, an internal tool coined Super Search was developed as part of Headlamp that enables rapid drill-down into the inverter fleet for troubleshooting and analysis purposes.

Additionally, outside the program, a new inverter direct-monitoring user interface was created that leverages the SEGIS database and API for inverter data. This application illustrates yet another use of the database and API. Many third-party stakeholders are also expected to make use of the APIs. Figure 34 shows the new inverter direct-monitoring interface for AE customers that leverage the SEGIS database and API.

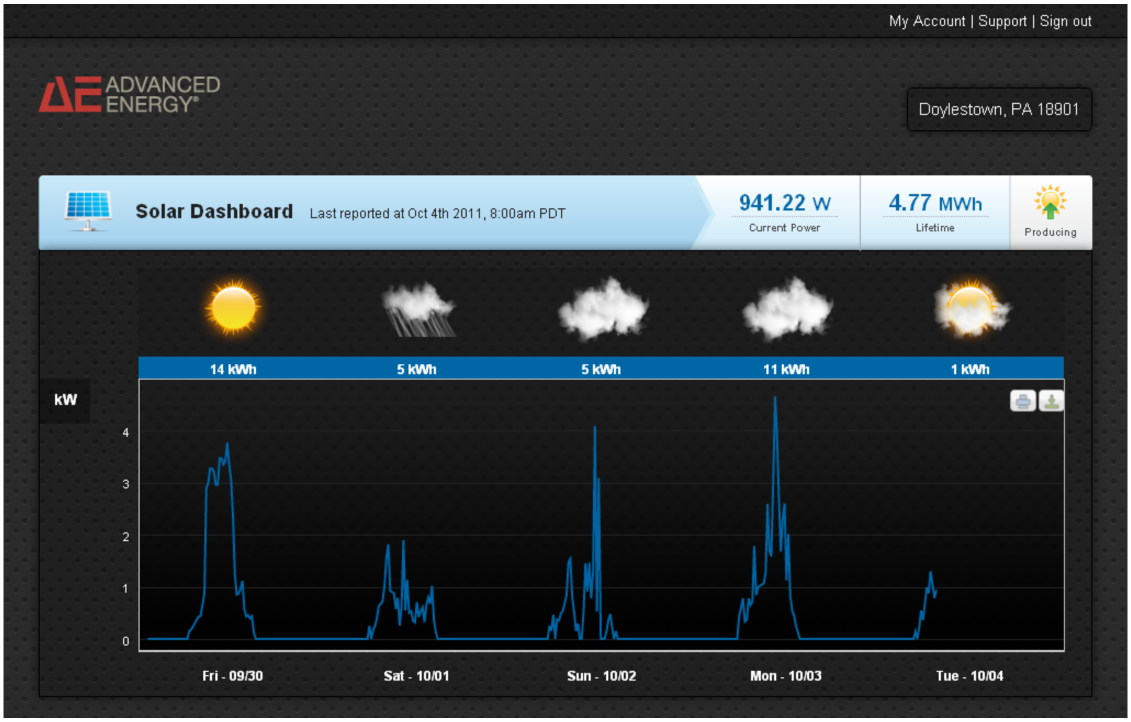

Figure 34. Inverter monitoring interface leveraging SEGIS database and API.

The team successfully developed and commercialized a complex database and API during the SEGIS program. Software projects like this are never complete, but the team delivered substantial value throughout the program, leveraging the database, API, and user interfaces for reliability initiatives to enable the other SEGIS deliverables and to support a new customer inverter monitoring solution. The team is excited about the long-term value and capabilities of this platform both to AE and to external stakeholders.

5 Perceived Impacts for the Utility, Customer and PV Applications Future

The SEGIS-developed technologies are targeted at solving many of today's issues around high-penetration PV, system costs, and increased functionality. From the utility perspective the developed technologies allow for increased penetration levels of PV across the distribution feeders as reactive power support may be demanded to assist in keeping system-wide voltage within pre-defined limits. Further, through careful analysis, longevity of existing voltage regulation equipment can be preserved, even with the variability of the PV resources. Transmission capacity may be improved by sourcing and sinking the VAr demand closer to the point of use, improving overall broad system efficiency (through line loss reductions). The communications platform approach toward command and control (allowing for SCADA integration or standalone) allows for all systems throughout the governing control area to act as a coordinated, aggregate resource to improve the power quality and voltage stability of the broad distribution network. Lastly, as functionality improvements continue to allow for new modes of operation, control, and coordination, the economics (hence, cost) of the system begin to reflect the capability to improve long-term reliability as well as cost savings of the broader electrical power grid.

From a customer perspective, the SEGIS innovations allow for increased functionality and system optimization. The MPPT algorithm allow for the customer to specifically tune to their module type, increasing energy harvest over the life of the system. Secondly, with the platform approach to command and control, the customer building EMS can now interface the PV resource and optimize energy use as well as avoid demand charges by taking into account real-time performance of the PV resource. Lastly, the platform approach allows the customer to choose the right solution for their particular application, allowing for flexible, creative solutions to meet their individual needs.

The SEGIS program has also greatly impacted the direction of the PV industry as a whole, highlighting the capabilities of today's power electronic-based inverters, balance of system components, and an overall systems approach to solving challenges with high-penetration PV on an electrical system designed specifically for unidirectional power flow. The platform and systems approach will allow for new innovative solutions to solve future challenges without the need for a complete ground-up redesign. The partnerships created to address these challenges will continue to grow, leveraging broad expertise from multi-faceted organizations to solve these crucial system-level challenges. The SEGIS teams (consisting of U.S. employees and organizations) also have allowed for job retention and creation in a field of increasing uncertainty. AE alone was able to hire and retain exceptional talent to focus on providing the industry with solutions to meet today's and tomorrow's challenges. As the PV industry continues to grow, the importance of creating and maintaining these jobs within the U.S. becomes increasingly important. These new jobs will benefit the U.S. economy and will help insure the long-term safety and security of the nation.

6 Conclusions

With support from the SEGIS partnerships, cost-shared funding and technical assistance from Sandia National Laboratories, the AE team is confident that the project goals have been met and, in some cases, exceeded. The AE SEGIS team moved through conceptual designs and market analysis (Stage 1), prototype development and characterization (Stage 2), and finally moved toward commercialization in Stage 3.

Early in Stage 1, it became evident that the proposed focus was directly responsive to the anxieties of utilities regarding high penetrations of PV energy and adding value to PV installations. The technology advances required to address these concerns were proven in prototypes during Stage 2, with laboratory results confirming the functionalities and feasibility of the advances.

The AE-led SEGIS team leveraged a broad approach toward creating technologies that would assist the PV industry to overcome challenges associated with high-penetration PV energy while reducing total system costs. The team researched and developed technologies addressing BOS and inverter-specific, performance-enhancement, and economic-specific focal points. The partnerships created throughout the SEGIS program have allowed for rapid product developments while incorporating a platform approach to specifically target future enhancements. These partnerships would not have existed without the SEGIS program, its goals and objectives, and the need to develop system-level solutions. The three-year program goals, expectations, and outcomes have been detailed throughout this report, highlighting many of the developed technologies, their respective impacts to the industry, and their expandability toward future applications. The growth of the industry (largely driven by local RPS) continues to drive requirements for advanced system functionality as well as innovations in new technologies.

At the beginning of the SEGIS program AE believed that much of the developed functionality would be unnecessary for many years; however, this was proven not to be the case as many of the developed technologies are being requested today. AE and its partners provided market-ready, innovative solutions through to commercialization at the closure of the three-year program and plan to continue development of the remaining technologies at a pace required by the market. Many barriers to high-penetration PV were overcome as a result of the SEGIS program, as it acted as a catalyst to highlight industry needs leveraging a systems-level approach.

The successful SEGIS Demonstration Conference held at Portland General Electric's Prologis PV installation on September 21, 2011, exercised all of the SEGIS capabilities developed over the three years. Major successes demonstrated included Synchrophasor-enabled anti-islanding, VAr control, ramp-rate control, PF control, low-voltage ride through, and power-management functions. The major successes depended heavily on developed communications.

Some technical work remains before extremely high levels of PV generation become commonplace on utility distribution systems. Regulatory and legal considerations, policy, standardization, codes, value assessment, and compensation matters are all challenging and critical to wide and routine deployment. All are eminently solvable given the powerful economic opportunities awaiting resolution. "The Markets will answer" is a non-trivial assertion.

Going forward, government and industry are already moving on the SEGIS advances, as evidenced by industry, EPRI, IEEE, university, and national labs projects. National Institute of Standards and Technology (NIST), DOE, and other agencies are now aggressively providing funding—for example, the follow-on DOE opportunity designated SEGIS-AC (SEGIS-Advanced Concepts) program. Work continues on further advancing concepts, components, and methodologies developed during the three stages of the SEGIS contract.

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