Pacific Gas and Electric Company

EPIC Interim Report

Program	***Electric Program Investment Charge (EPIC)***
Project	***EPIC 2.03A: Test Capabilities of Customer-Sited Behind-the-Meter Smart Inverters***
Reference Name	***EPIC 2.03A: Smart Inverters***
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Table of Acronyms

BTM	Behind-The-Meter
CAISO	California Independent Systems Operator
CES	Customer Energy Solution
CPUC	California Public Utilities Commission
CSIP	Common Smart Inverter Profile
DERMS	Distributed Energy Management Systems
DIDF	Distribution Investment Deferral Framework
DRP	Distribution Resources Plan
EPIC	Electric Program Investment Charge
EV	Electric Vehicles
ICT	Information and Communications Technology
M&C	Monitoring and Control
NWA	Non-Wires Alternative
PCC	Point of Common Coupling
PG&E	Pacific Gas & Electric
PPAs	Power Purchase Agreements
PTO	Permission to Operate
PV	Photovoltaic
R&D	Research and Development
RFO	Requests for Offering
RPS	Renewable Portfolio Standard
SI	Smart Inverter
SOW	Statement of Work

1 EXECUTIVE SUMMARY

This interim project report documents the achievements to date in Pacific Gas and Electric Company's (PG&E) Electric Program Investment Charge (EPIC) *Project 2.03A, Test Capabilities of Customer-Sited Behind-the-Meter Smart Inverters*. This report highlights key learnings already gained from the project that have industry-wide value and urgency given recent changes to California Rule 21 Tariff[1], which pertains to DER interconnection requirements. As the industry and CA stakeholders converge on a set of standards for Smart Inverter (SI) operation, communication and interconnection, PG&E felt it was important to highlight these interim observations on SI technology's key capabilities and areas for improvement.

The project aims to demonstrate the functionality of customer-sited behind-the-meter (BTM) photovoltaic (PV) Smart Inverters[2] (SI) and the grid impacts of their use. To date, PG&E has demonstrated the use of residential customer-sited PV SI technologies and communication infrastructure to mitigate potential local grid issues related to high penetration of customer-sited distributed energy resources (DERs) on two electrical distribution feeders ("Location 1"). PG&E is still working on a demonstration on one additional feeder ("Location 2"). These ongoing project activities are specifically targeting high voltage issues attributed to Location 2's high PV penetration and an evaluation of a vendor-agnostic aggregation platform to remotely monitor and make settings changes to the SI assets. Testing at Location 2 of the project is expected to be completed in late 2018 and will be documented in a separate report, which will also include findings from in-flight SI laboratory testing and modeling.

In recent years in California, distributed solar PV penetration has increased and growth is expected to continue. As of May 2018, PG&E has over 350,000 solar customers and is adding approximately 5,000 each month. This trend is driven in part by consumer preferences and in part by complementary legislative and regulatory actions. These include California's Renewable Portfolio Standard (33% renewable[3] by 2020 and 50% renewable by 2030[4]), net energy metering (NEM) policies, and federal tax subsidies incentivizing residential and commercial PV adoption[5]. In February 2015, the California Public Utilities Commission[6] (CPUC) issued the Distribution Resources Plan (DRP) Rulemaking R.14-08-013, which foresees incorporation of DERs into day-to-day grid operations and long-term distribution grid planning and investment decisions.

While distributed PV and other DERs represent an important part of the resource portfolio needed to reach California's clean energy and DER integration objectives, high distributed solar penetration has been linked to grid reliability issues. Industry experience and studies have suggested that in some instances, high distributed solar penetration can cause thermal and voltage violations, power quality issues, and

[1] CPUC Draft resolution E-4920 issued on 4/26/18 sets the power priority mode as *reactive power priority* mode

[2] A Smart Inverter is an advanced version of a standard inverter, which converts the variable direct current (DC) output of a solar photovoltaic system to alternating current (AC) that can be fed into the electric grid or used onsite. In addition to this standard inverter function, Smart Inverters have the capability to communicate (receive remote operation instructions and communicate measurements/status), and to make autonomous decisions to help maintain grid reliability and power quality.

[3] Senate Bill X1-2: http://www.energy.ca.gov/portfolio/documents/sbx1_2_bill_20110412_chaptered.pdf

[4] Senate Bill 350: http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB350

[5] Solar Investment Tax Credit: https://www.energy.gov/eere/solar/downloads/residential-and-commercial-itc-factsheets

[6] Distribution Resources Plan (R.14-08-013) http://www.cpuc.ca.gov/General.aspx?id=5071

adverse impacts on protection systems due to reverse power flow[7,8]. High distributed solar penetration is also using up the existing hosting capacity margin on the distribution system. Higher penetration levels may require traditional distribution grid upgrades, such as transformer replacement or new voltage regulation equipment[9].

PG&E forecasts that by 2020, roughly half of all PV interconnected to PG&E's electric distribution system will be equipped with SIs and forecasts 1 million total SIs on its system by 2025. A deeper understanding of SI functions and potential will enable PG&E and other utilities to incorporate SI-equipped DERs into distribution grid planning and operations at scale.

SI functionality can help mitigate distribution grid issues associated with high DER penetration. Autonomous SI functions such as anti-islanding, voltage and frequency disturbance ride-through and "soft-start" after an outage can help to maintain grid safety, power quality and reliability. Additionally, the use of autonomous reactive (Volt-VAR) and active (Volt-Watt) power output control is a way for SIs to enable DERs to maintain grid voltage. While autonomous SI settings and remote change of autonomous settings may address some grid constraints, active management of advanced SI functions (such as sending real or reactive power set points) is likely to be needed in other instances. Utility investment in new capabilities will be needed to integrate intermittent renewables and fully realize the value of such SI functionality at scale. Currently, utilities like PG&E lack visibility into the impact of DERs on local voltage and capacity, whether those impacts are forecasted or seen in real-time. To integrate intermittent renewables and realize the full benefits of SI functionality beyond autonomous functions, utilities will need new modeling capabilities to better characterize and forecast the operations of SI-equipped DERs. In addition, utilities would need to upgrade the existing communication and control systems to engage active SI management and potentially provide other distribution grid services. New capabilities needed by utilities to dynamically realize SI value include both software solutions (such as a coordinating platform that provides SI visibility to the utility and then optimizes and dispatches DERS through the SI) and hardware solutions both on the distribution grid and at the DER facility (such as ADMS and additional visibility/monitoring devices on the distribution grid, e.g. line sensors, to supplement visibility at end devices).

The project activities documented in this interim report demonstrate the technical potential of SIs to enable BTM PV to maintain local voltage and highlight next steps to enable scalability and to fully realize their ability to mitigate issues associated with high DER penetration and their potential value as a grid resource. With additional utility investments that enable the distribution grid operator to achieve better utility situational grid awareness, visibility, coordination and control capabilities, SIs have the potential to play a key role in shaping California's energy future.

This demonstration's objectives were focused on exploring several SI functionalities recently adopted by the California Public Utilities Commission (CPUC). In early 2013, the Smart Inverter Working Group (SIWG) was formed to update Rule 21[10] Rulemaking R.11-09-011, to incorporate advanced SI technical capabilities. Phase 1 (Autonomous Functions) and Phase 2 (Communication requirements including default IEEE-2030.5 protocol) became mandatory in 2017 and 2016, respectively. Phase 3 of the SIWG's

[7] Emerging Issues and Challenges in Integrating Solar with the Distribution System: https://www.nrel.gov/docs/fy16osti/65331.pdf
[8] High-Penetration PV Integration Handbook for Distribution Engineers: https://www.nrel.gov/docs/fy16osti/63114.pdf
[9] http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442455013
[10] Rule 21 is the interconnection tariff that each Utility has; PG&E Rule 21 tariff https://www.pge.com/tariffs/tm2/pdf/ELEC_RULES_21.pdf

recommendations[11] cover advanced SI functions, and they were approved by the Commission in April 2018 through resolution E-4898[12]. Beginning in 2019, SIs will be required to have the capability to receive remote operation instructions and communicate measurements and status. This demonstration provides several actionable findings, discussed below, which will help inform future investments needed to leverage the capabilities of the newly adopted SI functionalities as a tool to mitigate the distribution grid issues associated with high DER penetration.

Key Activities and Objectives

The overall EPIC 2.03A project activities are summarized in Table 1 below:

Table 1: EPIC 2.03A Key Activities

Activity	Covered in this Interim Report?
Location 1 SI Field Testing	Yes – see Table 3 for more detail
Location 2 SI Field Testing	No (Will be covered in Final Report)
SI Lab Testing	No (Will be covered in Final Report)
SI Modelling Study	No (Will be covered in Final Report)

The overall EPIC 2.03A project objectives are summarized in Table 2 below:

Table 2: EPIC 2.03A Key Objectives

Objective and Description	Covered in this Interim Report?
A. Through field studies in two distinct locations, evaluate the technical ability of SIs to influence secondary and primary voltage by adjusting reactive and real power output autonomously.	Yes – Location 1 evaluated SI impact to secondary voltage
B. Measure customer curtailment from Volt-VAR/Volt-Watt function activation.	No – This is an ongoing activity (Final Report)

[11] SIWG Phase 3 DER functions recommendations to the CPUC for Rule 21 - Phase 3 function key requirements, and additional discussion issues: http://www.energy.ca.gov/electricity_analysis/rule21/documents/phase3/SIWG_Phase_3_Working_Document_March_31_2017.pdf SIWG
Phase 1 defined seven autonomous functions, and all new inverter-based installations are required to be equipped with SIs capable of performing these functions as of September 2017 (CPUC Decision 14-12-035: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M143/K827/143827879.PDF)
SIWG Phase 2 covered communication protocols for SIs and was approved by the Commission in April 2017 (SIWG Phase 2 recommendations for utility communications with DER systems with SIs: http://www.energy.ca.gov/electricity_analysis/rule21/documents/SIWG_Phase_2_Communications_Recommendations_for_CPUC.pdf). Implementation of the Phase 2 recommendations is available through each utility's Rule 21 interconnection technical handbook (PG&E Rule 21 tariff https://www.pge.com/tariffs/tm2/pdf/ELEC_RULES_21.pdf), and the IEEE 2030.5 Common Smart Inverter Profile (CSIP) implementation guide.
[12] http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M200/K267/200267616.PDF

C. Demonstrate and evaluate the reliability of communications to provide visibility, monitoring and change settings for SI-equipped PV using both a vendor-specific aggregation platform and a vendor-agnostic utility aggregation platform.	Yes – Location 1 evaluated a vendor-specific aggregation platform
D. Clarify SI technology requirements to integrate and operate SIs, and characterize challenges to deployment at scale relative to today[13].	Yes
E. Through lab testing, understand SI performance under a range of distribution grid conditions.	No - This is an ongoing activity (Final Report)
F. Through a vendor-led modelling study, evaluate the impact of PV and PV + Storage with and without SIs and perform a cost-benefit analysis of SIs on PG&E's system as compared to traditional distribution grid upgrades.	No - This is an ongoing activity (Final Report)

Collectively, the above project objectives are intended to enable utilities with high DER penetration to understand the functionalities, requirements, and investments needed to utilize SI capabilities.

To date, the EPIC 2.03A project has succeeded in demonstrating SI functions at residential customer-sited behind-the-meter (BTM) PV sites at Location 1. This portion of the project partnered with an aggregator vendor to deploy the SIs, which were individually monitored and managed from June to October of 2017. The Location 2 project activities, lab testing and modeling are still underway and will be completed in October 2018.

Key differences between field testing at Location 1 and Location 2 of the project are highlighted in Table 3.

Table 3. EPIC 2.03A Smart Inverter Project Location 1 and Location 2 Differences

Project Parameters	EPIC 2.03A Location 1 (This interim report)	EPIC 2.03A Location 2 (Still ongoing)
Voltage impacts demonstrated from changing settings on SIs connected to BTM customer-sited PV	Local (secondary) voltage impacts	Secondary and primary voltage impacts
Customer type	Residential	Commercial/agricultural
Deployment dates	New customers acquired and SI assets installed over first half of 2017; tested through 11/17	Existing SI assets retrofitted with new SI firmware in early 2018; tested through 9/18

[13] As a related objective to this SI technology demonstration and using some of the same DERs as this project, PG&E concurrently aimed to demonstrate the ability of SI-equipped PV to be monitored and dispatched remotely by a DER Management System (DERMS). For the results of this demonstration, please see the forthcoming report on EPIC Project 2.02.

# of PV assets and capacity	15 assets, 62.5 kW nameplate capacity	14 assets, 4.5 MW nameplate capacity
Feeder penetration of PV assets included in project (nameplate/peak feeder demand)	Less than 1% of peak feeder demand (2 feeders); overall, test feeders had a moderate level of BTM PV penetration	35% of peak feeder demand (1 feeder); overall, test feeder has a high level of BTM PV penetration (~70% of peak feeder demand)
Feeder stiffness and power quality issues	Stiff feeders (less prone to voltage disturbances based on loading and impedance) no observed voltage/power quality issues or reverse flow	Feeder with prior voltage and capacity constraints as well as observed reverse power flow
Volt-VAR/Volt-Watt curves evaluated	Custom curves (non-default) designed to ensure active/reactive power functions activated	Rule 21 curve, HECO curve and 2 additional curves tested on existing high voltage conditions
Type of remote management of assets evaluated (Autonomous/passive or active/on-demand)	Autonomous/passive with the ability to schedule settings on a day-ahead basis	

Project Milestones

The following summarizes the key accomplishments of the residential SI technology (Location 1) demonstration project:

- Deployed and tested 15 PV systems, totaling 65.2 kW (DC) of residential SI-enabled PV installed capacity (Key Objective A).
- Executed 6 field tests, testing SIs' active/reactive power control (Key Objectives A and C):
  1. Fixed Reactive Power of 2 kVAR
  2. Fixed Reactive Power of 4 kVAR
  3. Volt-VAR (autonomous reactive power control)
  4. Fixed Active Power of 1 kW
  5. Fixed Active Power of 2 kW
  6. Volt-Watt (autonomous active power control)
- Demonstrated the ability of a SI system to influence local secondary voltages (Key Objective A).
- Qualified/quantified SI system remote command execution (Key Objectives C and D).
- Characterized communication reliability and latency, and system uptime (Key Objectives C and D).

Key Learnings and Recommendations

The following are the key lessons learned during this project's SI testing at Location 1:

- **SIs can enable BTM PV to help with local secondary voltage regulation through autonomous active or reactive power support.** (Key Objectives A, C and D) In this demonstration, SIs showed a nominal impact to voltage on the secondary system, indicating that SI functions could potentially be used to mitigate PV voltage impacts. The results demonstrate that the extent of impacts on secondary voltage depends on the amount of SI active or reactive power output, and the electrical properties of the secondary system.
    - On average, 1 kVAR of reactive power absorption resulted in a 0.25 V change at the SI terminal.
    - On average, 1 kW of active power output resulted in a 0.6 V change at the SI terminal, or about two times the voltage impact compared to a change of 1 kVAR reactive power.
    - These measured SI impacts on secondary voltages are specific to the local secondary system properties for this demonstration. Results may vary for secondary systems with different electrical properties and load conditions.[14]
    - While the project could measure SI impact at secondary (low voltage) systems[15], the capacity of PV deployed at Location 1 was insufficient to demonstrate any impact of SI operation on primary (medium) voltage[16].

- **SIs executed Volt-VAR functions as programmed.** (Key Objective A) The SIs provided reactive power support in line with Volt-VAR curve settings, either based on pre-programmed dynamic settings or previously-scheduled fixed reactive power setpoints. However, there were some exceptions when SI reactive power output was outside the threshold limits (+/-250 VARs), consistent with previously observed results in a lab setting[17]. This observation from testing is specific to each SI manufacturer and likely results from short-term changes in active power; ongoing project activities are expected to generate additional insight into the technology.

- **Volt-Watt functions executed as programmed when no other active power control commands were executed.** (Key Objective A) Once scheduled, SIs could follow a Volt-Watt curve when this was the only issued command. However, when Volt-Watt was enabled and an active power curtailment command was cycled on and off, Volt-Watt stopped executing for a short period of time (30 min). This

[14] The observed result in this project is dependent on the portion of the distribution system being considered. Low voltage, secondary distribution systems generally have a smaller reactive component to their impedance when compared to medium voltage, primary distribution systems. For this project, this resulted in active power having a larger impact on voltage than reactive power.

[15] Due to the project's low SI capacity relative to the respective secondary system's net load, voltage changes attributable to SIs were difficult to measure accurately. This is a key driver for Location 2 of the project using commercial scale PV sites, which will explore SI voltage support capability in a system with a greater penetration of SI-enabled PV. This ongoing work aims to generate more results of SI impact on the secondary voltage system and potentially on the primary voltage system, as well.

[16] Given that the feeder chosen was of a relatively higher voltage, urban, and short, a higher SI penetration would be required to make impact on the primary system. However, this outcome would vary across the system; for instance, a lower voltage, rural, or long feeder may have had a different outcome.

[17] In PG&E's Smart Grid Pilot Program, oscillations in reactive power output of SIs were observed under large secondary side load disturbances when Smart Inverters were operated in a Volt-VAR operating mode with aggressive VAR-Volt slope. Section 3.2.9, p. 161: https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_4990-E.pdf

outcome is SI manufacturer-specific[18] and was only observed in the context of the Location 1 field demonstration. Regardless, the priority and performance of SI functions like Volt-VAR, Volt-Watt and active power curtailment need to be established and tested by SI manufacturers in adherence with a clearly-defined set of industry standards.

- **Remote change of autonomous SI voltage curves and schedules using a vendor-specific aggregation platform is possible.** (Key Objectives A, C and D) Volt-VAR and Volt-Watt settings were dispatched remotely using the vendor's monitoring and control (M&C) platform, which allowed PG&E to simultaneously dispatch Volt-VAR curves to fifteen individual SI assets. However, in this project the dispatch of Volt-Watt curves required ad hoc vendor assistance, as the vendor-utility SI management interface was not set up at the project outset for PG&E to change Volt-Watt settings directly. PG&E provided individual SI Volt-Watt curve settings to the vendor the day before the test execution, and the vendor "pushed" those settings to individual SI assets in the field. While autonomous SI Volt-Watt/Volt-VAR settings are not likely to be changed frequently once implemented, the ability to remotely change settings in real time may be required for on-demand or active SI use cases. More streamlined remote function-setting may be possible with additional advances in technology since the time of testing at Location 1 of this project.

- **While autonomous SI settings and remote change of autonomous settings may address some grid constraints, there is likely still a need for active SI management in some instances (such as sending real or reactive power set points)**. (Key Objectives C and D) The project primarily evaluated SI capability to provide secondary voltage support in a passive fashion, where "set & forget" parameters would be pre-loaded onto SIs by manufacturers in compliance with Rule 21 requirements and allowed to run independent of any additional, external active control signals. Such passive management through autonomous Volt-VAR/Volt-Watt curves may be sufficient to address some scenarios, such as distribution voltage rise caused by high DER penetration and allowing additional DERs to interconnect on circuits with limited remaining hosting capacity. Active control (the ability to dispatch commands in response to real-time grid conditions) could potentially extend SI benefits to use cases such as on-demand curtailment by a grid operator or instances where SI-controlled DERs may be providing distribution grid services as part of a non-wires alternative (NWA) deferral project. Most utilities, including PG&E, do not currently have the foundational capability to actively monitor or control DERs. Such applications would require SI-controlled DER solutions to be integrated with the utility DER management platform and customized to specific grid conditions, configurations and needs. Cost benefit analysis may be needed to determine whether the NWA and the market benefits outweigh the integration costs, including storage, communications and grid infrastructure upgrades, that may be required to capture all of the potential DER benefits.

- **Reliable communication links are critical for success. Communication infrastructure performance must improve relative to what was observed in this project for use cases that require real time active control at scale**. (Key Objective C) Location 1 testing utilized residential Wi-Fi internet in combination with Zigbee[19] to communicate with the residential PV assets, which is generally a low-

[18] The cause of this behavior in this part of the project is suspected to be a glitch in the SI firmware developed for this demonstration.

[19] Zigbee is an IEEE 802.15.4-based specification for a suite of high-level communication protocols used to create personal area systems with small, low-power digital radios, such as for home automation, medical device data collection, and other low-power low-bandwidth needs, designed for small scale projects which need wireless connection.

cost solution. When assets were online, they met most use case requirements with latency that was within SCADA (Supervisory Control and Data Acquisition) current timeout limits[20]. The maximum latency observed was 18.0 seconds, and the average latency observed was 8.6 seconds. However, asset availability/uptime was a challenge:

- 65% of the time the communication uptime was between 99% to 100%.
- The probability of communication uptime being less than 95% was 15%.

While several factors may have contributed to the communications challenges observed in this project,[21] more reliable and standardized communication performance would be recommended for assets to participate actively in grid services at scale (e.g. if the use cases require active or real-time control, such as sending real or reactive power set points). As of this writing in July 2018, no such communication standards exist. Additionally, no national standards exist to ensure that SIs are implemented securely, and communication protocols for control and coordination are highly variable in the level of security offerings. Further exploration and testing is required to develop and validate cybersecurity requirements which safeguard against various threat scenarios intended to maliciously operate SIs outside of their expected manner.

- **Current utility operational systems are not yet capable of fully integrating large numbers of SIs effectively and using this advanced SI technology to its fullest extent. Further utility investment is required to deploy technology to connect to SIs and utilize DERs as a reliable grid resource in the future, especially if SIs are controlled at scale and in real-time across the electrical distribution system** (Key Objectives A, B, and C). Utilities will need to invest in foundational capabilities and systems[22] to enable 1) real-time communication of distribution dispatch instructions to the aggregators/SIs (active control), and 2) automated optimization of grid operations leveraging both traditional distribution operations equipment and SI-equipped DERs. Given the dynamic operating conditions of each feeder and the localized distribution grid, the frequent rerouting of power over different distribution feeders via switching to minimize impact of local outages, and the need for work clearances to ensure the safety of the public and utility crews, operational capabilities that can automatically optimize solutions for grid conditions and communicate signals to aggregators and/or individual DERs would greatly enhance the value of DERs to the grid operator and planner.

  In this demonstration, PG&E communicated a pre-established test plan directly to the aggregator's platform. To leverage BTM PV SIs as a more widely deployed resource across the distribution grid on a real-time basis, grid operations and control systems will need to be able to provide instructions to localized DERS and optimize the tools available to grid operators to effectively, efficiently and safely manage real-time operating conditions. These new capabilities are currently being explored as part of PG&E's distribution technology roadmap, which will seek to improve situational awareness and operational efficiency through implementation of an Advanced Distribution Management System (ADMS), additional SCADA enhancement and integration, advanced planning tools, and network upgrades.

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[20] Maximum SCADA response time is 30 seconds before a communication error is incurred.

[21] Challenges included the lack of vertically-integrated hardware and standardization among equipment and software providers at the time, (which contributed to low up-time for a significant proportion of assets with this specific communications configuration), and the small sample size (15 assets) available with this demonstration.

[22] This would include an Advanced Distribution Management system that integrates a traditional Distribution Management System (DMS) with distribution SCADA, SCADA enhancements, advanced planning tools, and network upgrades.

Additional advanced DER management capabilities are also being contemplated to optimize and control the use of DERs to meet dynamic distribution grid needs and constraints. Although SI-equipped DERs may participate in vendor aggregation platforms that can optimize and dispatch DERs within a fleet, the utility integrated grid platform will need to translate grid needs into signals delivered to DERs or to aggregations of DERs. These new capabilities, along with foundational ADMS and network upgrades, will be necessary to integrate SIs and fully realize the value of SI-equipped DERs in use cases and locations where active control can add value.

Beyond utility foundational systems and advanced DER management capabilities, further growth and investment continue to be necessary in several areas, including: consistent implementation of SI standards (as developed in the SIWG and approved by the CPUC), sufficient penetration of SIs where needed on the distribution grid, maturity in interactions and coordination between the utility and DER operators/aggregators, reliable communications, and robust cybersecurity standards and implementation.

- **Targeted customer acquisition and deployment of customer-sited DERs is a significant project execution risk for grid investment deferral, especially under short project timelines.** (Key Objective D) The customer acquisition process for this project was vendor-led, and vendors in the Location 1 SI deployment encountered significant challenges in meeting customer acquisition objectives. Customer acquisition was subject to significant delays, and targets were ultimately not met. These may have been related to limited access to customer information, customer fatigue from door-to-door solar outreach, existing solar system ownership structure and restrictions on curtailment, and the approach to the customer engagement strategy.
    - **Identify and account for customer acquisition risks** – Along with *EPIC Project 2.19C BTM Storage*, this part of the project learned that customer acquisition risks should be more heavily weighted to establish more realistic timelines and projected outcomes for BTM projects, particularly when targeted deployment of DERs is required for safe operation of the grid (e.g. as part of a non-wires alternative PV + storage capacity project). Additional detail on these learnings can be found in the Final Report for *EPIC Project 2.19C Enable Distributed Demand-Side Strategies & Technologies (in short, Behind-the-Meter (BTM) Storage).*[23]

    - Utilities should find alternatives to new customer acquisition when pursuing demonstrations with the ability to deploy new assets, such as identification of feeders with pre-existing customer-owned and not 3rd party-owned DERs. This was the approach taken with Location 2 of EPIC 2.03A, where existing commercial-scale SIs could be retrofitted for the purposes of the demonstration.

    - Difficulty encountered in targeted DER deployment—and difficulty encountered in targeted retrofit of solar to SI— validates the establishment of a requirement for SI functionality in all new inverter-based DER installations.

- Building on the Location 1 work, further exploration is currently underway in the ongoing EPIC 2.03A project:
    - **Evaluate the potential for higher penetration of SI-enabled PV assets to provide both secondary and primary voltage support** (Key Objective A) – Relative to available DERs at

[23] https://www.pge.com/pge_global/common/pdfs/about-pge/environment/what-we-are-doing/electric-program-investment-charge/PGE-EPIC-Project-2.19.pdf

Location 1, greater SI-enabled PV asset penetration at Location 2 will enable a more robust assessment of SI function effectiveness in addressing grid level voltage issues stemming from high BTM PV penetration. By retrofitting a higher percentage of existing PV installations with SIs (35% of PV name plate rating/peak feeder demand), Location 2 testing will explore autonomous SI operation impact on primary feeder voltage. This feeder is also more prone to voltage disturbances than the Location 1 feeders and has previously experienced high voltage conditions, possibly tied to its overall high PV penetration (predominantly customer-owned commercial installations where SI retrofits required for the project were possible). Using this feeder to quantify voltage response to changes in SI reactive and active power operation will increase understanding of autonomous SI functionality.

- **Evaluate a vendor-agnostic aggregation platform** (Key Objectives C and D) – Location 2 of this project will also evaluate remote monitoring of aggregations of solar assets, as well as the remote implementation of changes to SI settings. While Location 1 used a vendor-specific aggregation platform, Location 2's configuration will use a vendor-agnostic utility aggregation platform and existing satellite communications infrastructure to relay information from each solar PV site to a cloud-based server, where it will then be processed and sent to PG&E. Ideally, such a system can communicate to a number of different SI vendors and installers found within a utility's territory. Testing will seek to:
    - Inform PG&E's perspective on the complexity of coordination of large numbers of SIs on its system
    - Inform telemetry communication requirements for SI assets in various modes of functionality
    - Assess latency and reliability of the DER communications infrastructure, as well as ease of integration of the aggregation platform with PG&E's IT systems
    - Inform future advanced technology SCADA, ADMS (Advanced Distribution Management System) and DERMS requirements

- **Evaluate customer energy generation curtailment as a function of SI settings** (Key Objective B) – Customer energy curtailment due to Volt-VAR and Volt-Watt functions will be measured in the Location 2 field demonstration by maintaining one baseline SI at each test site. The baseline SI will not run any Volt-VAR or Volt-Watt curves, and energy production at this SI will serve as a baseline for comparison against other SIs at the site actively running curves[24]. Additionally, a curtailment predictor tool will be built to estimate customer curtailment from the Volt-Watt function. This tool will estimate potential reduction in customer generation using the customer's voltage profile pre- and post-interconnection.

- **Conduct a series of SI test cases in the laboratory** (Key Objective E) – The objective of these tests is to gain an understanding of how SIs perform in both normal and extreme grid conditions. Key learnings PG&E hopes to gain from lab testing:
    - SI ability to follow Volt-VAR and Volt-Watt curves and performance in areas where these curves overlap
    - Impact of harmonics on residential SIs

[24] The 14 PV sites evaluated at Location 2 of the demonstration each have multiple SIs per site, from 4 at the smallest site (132 kW) to 41 at the largest site (984 kW).

- Impact of harmonics on electric vehicle (EV) Level 2 and DC super chargers (DCFCs)
- Impact of out of phase reclosing on three-phase SIs

- **Explore potential cost savings and benefits of SIs across the PG&E system** (Key Objective F) – Through a modeling study, ongoing EPIC 2.03A activities will technically determine the necessary conditions and requirements for SIs to provide benefits to utility customers. Potential benefits include supporting voltage to avoid distribution upgrade costs, and guiding PG&E on how best to engage with SI-enabled DERs in the future. This analysis will be specific to PG&E's system and will evaluate SI functions on several representative distribution feeders. Insights from this modeling demonstration will drive greater understanding of:
    - Costs/benefits of SI deployment based on grid characteristics
    - Engineering standards regarding voltage rise calculations for BTM DERs
    - Penetration and siting considerations for DER impacts
    - Impacts of SI-enabled PV systems when coupled with passive/autonomous battery storage
    - Evaluation of the cost-effectiveness of SIWG Phase 1 and Phase 3 functions, to determine incremental benefits of autonomous SI functions

Implementation Challenges and Resolutions

Key implementation challenges encountered by the project in the completed Location 1 testing and their respective resolutions are listed in Table 4. Key Challenges and Resolutions. These are discussed in more detail in Section 3.7 Challenges.

Table 4. Key Challenges and Resolutions

Key Challenges	Resolution
Customer acquisition took longer than expected; the targeted SI capacity deployed by the vendor was achieved 10 months post-target date. Up to 500 kW of residential, SI controllable, PV nameplate capacity was targeted. One vendor exited the project, and the remaining vendor achieved 130 kW, 62.5 kW of which was used for the tests in this demonstration.	Because customer acquisition resulted in fewer installations than expected in the time available, PG&E modified the DER testing approach from “test all at the same time” to “test as becomes available”, to reduce further project delays. In addition, the intent was for Location 1 of the 2.03A project to use the field resources deployed for its testing during specified times, while other co-located demonstration projects would use the field resources during other times. Due to customer acquisition-related project delays, PG&E modified the testing approach to instead allocate a subset of field resources to this project relative to other demonstration projects, to mitigate timeline delays. However, this resulted in collecting fewer data points than anticipated. While the modifications to the testing approach at Location 1 of 2.03A enabled the project to test SI impact on local voltage, PG&E will gain additional learnings on voltage impact at the primary using a higher SI-controllable PV penetration at Location 2 of the project (results expected late 2018).
Vendor software and hardware malfunctions delayed commissioning, site acceptance testing, and field demonstration. Unanticipated issues that were identified by the vendor during commissioning include: • Verification of communications uptime to address poor or no communication with SIs • Need to upgrade communication gateway firmware • Configuration of a unique PAN ID for the site assets to ensure isolation from neighbouring Zigbee networks	DER Vendors were responsible for addressing problems with their technology suppliers/vendors. Because SI gateways were responsible for low connectivity in some cases, some SI gateways were replaced to improve communication performance. Also, data polling frequency was reduced from approximately 10 seconds to 3 minutes at two SI locations with poor communication performance to improve communication uptime. For future technology demonstration projects or full-scale SI deployment, greater vertical integration of hardware and/or standardization among equipment and software providers could help solve these problems.

Key Challenges	Resolution
Custom (non-default) Volt-Watt curves were uploaded to individual SIs by vendor staff on PG&E request the day before the test. This was not only time-consuming but also limited PG&E's ability to adjust the settings in near real-time based on voltage conditions in the field during testing.	Custom Volt-Watt curves were used to force SIs to perform as if SIs were experiencing voltage conditions outside of Rule 2 limits, since voltages on the Location 1 field demonstration feeder were within Rule 2 limits. If used for autonomous SI operation, Volt-Watt curve set points are not expected to change frequently once implemented, but the ability to change SI settings in real time may be needed for active or "on-demand" use cases.

The challenges identified above are specific to the vendor-provided SI technology, the configurations tested, and the "state-of-the-art" at the time of deployment and testing in 2017. As with any new technology, SI solutions require additional standardization and investment over time to reach maturity. Overall, PG&E believes that the industry is on the right track to make SIs a reliable and scalable grid resource over time, with the understanding that some of the above issues may have already been addressed since the time of EPIC 2.03A field testing.

Conclusion

EPIC 2.03A Location 1 findings demonstrated basic technical functionality of SI autonomous functions designed to mitigate local voltage issues associated with high DER penetration, and characterized remaining hurdles to scaled SI deployment for grid support. While this initial work in the project did not present findings on SI ability to affect primary voltage (a focus of the remaining time in the project), it did demonstrate the potential for local voltage support from SIs to help mitigate local secondary voltage challenges caused by high PV penetration. SI ability to impact secondary voltage demonstrates that, with necessary improvements to the technology and processes related to its deployment, SI technology represents a promising avenue to address California's goals for DER integration.

At the same time, project activities completed to date provided insights into communication performance, highlighting uptime as a concern for implementation at scale. While latency observed in this demonstration may qualify BTM SI technology in autonomous (set & forget) applications, communications uptime must be improved relative to this project's observations to remotely (on-demand) leverage SI control capabilities in system operations. To enable these active control use cases, investment in utility foundational systems and advanced DER management capabilities will be needed. This project also illustrated challenges around targeted deployment of SI-equipped PV (getting the desired quantity of resources, when and where they were needed) and around having sufficient penetration to rely on SI-equipped PV for distribution system needs.

These findings on the potential use of SI autonomous capabilities to maintain local voltage are expected to be valuable for distribution grid operations, distribution planning, and customer programs. Feedback from this technology demonstration can inform process changes and utility requirements needed to successfully integrate renewable resources controlled by SIs. Specifically, ongoing EPIC 2.03A testing may provide additional evidence of SI ability to support secondary voltage that allows PG&E to update its secondary voltage rise standards for new PV interconnection. Learnings can also inform the Distribution

Resources Plan (DRP) and Integrated Distributed Energy Resource (IDER) proceedings and ongoing Rule 21 Tariff Order Instituting Rulemaking (OIR), and Grid Modernization initiatives.

Location 1 of EPIC Project 2.03A evaluated residential SI technology, controlled through a vendor-specific aggregation platform, as a foundational technology. However, many questions remain. BTM SI technologies need to be further demonstrated, especially SI operation impact on both primary and secondary voltage support at higher PV penetration levels. With the Location 2 component of the project, a commercially-focused SI field trial, PG&E will evaluate SI management through a vendor-agnostic utility aggregation platform, measure SIs' ability to influence voltage on the primary side of the transformer, and measure customer curtailment resulting from SI active and reactive power functions. Ongoing activities will also include lab testing to evaluate SI response to a variety of grid conditions as well as a modeling demonstration to perform a cost-benefit analysis of SI functions on PG&E's distribution system.

Once completed, EPIC Project 2.03A will enhance understanding of the potential of SI for electric utilities, regulators, adjacent industries, policy makers, and prospective vendors, toward building a broader solution to the ultimate benefit of utility customers. PG&E plans to continue to champion this effort through continued support and presentations at industry meetings and to seek opportunities to continue to assess use of this technology.

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Morgan Metcalf: Project Business Lead
Samantha Piell: Project Manager
Junaid Fatehi: Project Engineer
Sabrin Mohamed: Project Engineer
Nicole Efron: Final Report Co-Author

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2 INTRODUCTION

This interim report documents the interim achievements of Pacific Gas and Electric Company's (PG&E) Electric Program Investment Charge (EPIC) *Project 2.03A, Test Capabilities of Customer-Sited Behind-the-Meter Smart Inverters*, and highlights key learnings from the project that have industry-wide value. This report also identifies future opportunities for PG&E to build upon these project learnings, many of which are currently being explored in ongoing project activities and will be documented in a separate report.

The CPUC issued two decisions that established the basis for this program. The CPUC initially issued D. 11-12-035, *Decision Establishing Interim Research, Development and Demonstrations and Renewables Program Funding Level,*[25] which established the Electric Program Investment Charge (EPIC) on December 15, 2011. Subsequently, on May 24, 2012, CPUC issued D. 12-05-037, *Phase 2 Decision Establishing Purposes and Governance for Electric Program Investment Charge and Establishing Funding Collections for 2013-2020,*[26] which authorized funding in the areas of applied research and development (R&D), technology demonstration and deployment (TD&D), and market facilitation. In this later decision, CPUC defined TD&D as "the installation and operation of pre-commercial technologies or strategies at a scale sufficiently large and in conditions sufficiently reflective of anticipated actual operating environments to enable appraisal of the operational and performance characteristics and the financial risks associated with a given technology."[27]

The decision also required the EPIC Program Administrators[28] to submit Triennial Investment Plans to cover 3-year funding cycles for 2012–2014, 2015–2017, and 2018–2020. On November 1, 2012, in A.12-11-003, PG&E filed its first triennial EPIC Application with CPUC, requesting $49,328,000, including funding for 26 Technology Demonstration and Deployment Projects. On November 14, 2013, in D.13-11-025, CPUC approved PG&E's EPIC plan, including $49,328,000 for this program category. Pursuant to PG&E's approved EPIC triennial plan, PG&E initiated, planned, and implemented Project 2.03A, *Test Capabilities of Customer-Sited Behind-the-Meter Smart Inverters*. Through the annual reporting process, PG&E kept CPUC staff and stakeholders informed on the progress of the project. The following is an interim report on this project, focused on the results from the first field test. A Final Report on Project 2.03A will be issued later in 2018.

EPIC 2.03A Key Objectives are aligned with other PG&E EPIC projects related to DER integration and will inform the ongoing Rule 21 and Distribution Resources Plan CPUC proceedings:

Table 5: EPIC 2.03A Alignment with other PG&E EPIC Projects and Policy Proceedings

EPIC Demonstrations	Policy Proceedings
EPIC 2.19C: Customer-Sited and Community Behind-the-Meter Storage • Demonstrated use of BTM energy storage technologies to reduce peak loading/absorb DER generation	**Rule 21: DER Interconnection Standards**

[25] http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/156050.PDF
[26] http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/167664.PDF
[27] Decision 12-05-037 pg. 37
[28] Pacific Gas & Electric (PG&E), San Diego Gas & Electric (SDG&E), Southern California Edison (SCE), and the CEC

<table>
<tr><td>EPIC 2.02: Distributed Energy Resource Management System (DERMS)

• Evaluated ability to monitor and coordinate DERs for grid services and informed Advanced Distribution Management System (ADMS) RFP</td><td rowspan="4">• Through the SIWG Phase 1, 2 & 3 recommendations, Rule 21 defines mandated SI functionality in CA

DRP: Locational Net Benefit Analysis, Integration Capacity Analysis, Grid Mod

• Objectives: Develop methodology to determine locational value of DERs / Analyze available DER hosting capacity / Upgrade technological capability of grid to integrate DERs</td></tr>
<tr><td>EPIC 2.22: Demand Reduction through Targeted Analytics

• Developed new analytical tool to identify customers & strategically target optimal locations for local demand reduction</td></tr>
<tr><td>EPIC 2.23: Integrate Demand Side Approaches into Utility Planning

• Developed tools and processes to integrate DER forecasts into distribution planning to meet DRP goals</td></tr>
<tr><td>EPIC 3.03: Advanced DERMS (proposed)

• Calculate & convey grid constraints for real-time DER dispatch to address grid & interconnection needs</td></tr>
</table>

3 PROJECT SUMMARY

The objective of EPIC 2.03A Location 1 field testing was to demonstrate the use of autonomous aggregated customer-sited BTM SI technologies to derive grid benefits, such as to support:

I. Local voltage regulation by controlling the SI reactive power output based on measured voltage at SI terminals (e.g., Volt-VAR control).
II. Grid reliability by curtailing the SI real power output to prevent voltage violations.

Full project objectives are summarized below in section 3.2 Project Objectives.

3.1 Issue Addressed

In recent years in California, distributed solar PV penetration has increased and growth is expected to continue. As of May 2018, PG&E has over 350,000 solar customers and is adding approximately 5,000 each month. This trend is driven in part by consumer preferences and in part by complementary legislative and regulatory actions. These include California's Renewable Portfolio Standard (33% renewable[29] by 2020 and 50% renewable by 2030[30]), net energy metering (NEM) policies, and federal tax subsidies incentivizing residential and commercial PV adoption[31]. With increased PV penetration, it is important to proactively mitigate potential issues of high penetration of PV. SI functionalities could help manage some

[29] Senate Bill X1-2: http://www.energy.ca.gov/portfolio/documents/sbx1_2_bill_20110412_chaptered.pdf
[30] Senate Bill 350: http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB350
[31] Solar Investment Tax Credit: https://www.energy.gov/eere/solar/downloads/residential-and-commercial-itc-factsheets

of these issues and become a cost-effective new tool for distribution planners and operators to utilize in managing the impact of DERs on the distribution grid.

A recent study by Navigant – commissioned by, and proprietary to PG&E (available upon request) – concluded that the amount of retail solar installed in PG&E territory in 2024 will be ten times the 2015 installed base, growing from 488 MW to 4800 MW.[32] This study concluded that high penetration of solar PV on feeders can cause the following distribution-level voltage-specific challenges in some instances:

- Reverse power flow exceeding line loading limits
- Feeder voltages exceeding acceptable voltage limits (+/- 5% of nominal value)
- Power quality issues (flicker) due to voltage fluctuations
- Impact on protection system not designed for reverse power flow conditions

The basic function of a standard inverter is to convert the variable direct current (DC) output of a solar PV system to alternating current (AC) that can be fed into the electric grid or used onsite. According to NREL, SIs perform this same function, but additionally address some of the above concerns and challenges associated with high variable renewable energy integration into the electric grid. Capabilities include monitoring and communication of the voltage and flow conditions at the inverter terminal, the ability to receive offsite operation instructions, and the capability to make autonomous decisions to maintain grid stability and reliability[33]. NREL cites that SIs can be used to support the grid in the case of high solar adoption in the following ways:

- Capability of "riding through" minor disturbances to frequency or voltage: Advanced inverters can direct a distributed generation system to stay online during relatively short, minor frequency or voltage disturbances rather than tripping offline which could further exacerbate issues.
- Capability to inject or absorb reactive power into or from the grid: Variability in the power output from distributed generation can make it difficult for grid operators to keep frequency and voltage levels within the required range.
- Capability to provide a "soft start" after power outages: Staggering the timing of the reconnection of distributed generation to the grid after an outage can help avoid spikes in active power being fed into the grid, limiting the risk of triggering another grid disturbance.

Since September 2017 California's Electric Rule 21 requires that all new distribution solar PV systems be interconnected via SIs. Since this technology is relatively new, there was a need to assess the performance of SI functions recommended by the Smart Inverter Working Group[34] (SIWG). The SIWG Phase 1 autonomous functions became mandatory in September 2017, after the California Public Utility Commission adopted seven functions that SIs must perform autonomously. The Phase 2

[32] "Distributed Generation Solar Photovoltaic Transmission and Distribution Impact Analysis," Navigant Consulting, August 31, 2015. (Commissioned by and Proprietary to PG&E).
[33] Smart Grid, Smart Inverters for a Smart Energy Future. https://www.nrel.gov/technical-assistance/blog/posts/smart-grid-smart-inverters-for-a-smart-energy-future.html
[34] See CPUC Rulemaking 11-09-011. http://www.cpuc.ca.gov/General.aspx?id=4154

recommendations were incorporated by the investor-owned utilities' (IOU) Rule 21 tariff revisions in December 2016. The SIWG Phase 3 recommendations[35] were approved by the CPUC in April 2018.

Table 6 below illustrates the Phase 1-3 SIWG functions, with the functions tested in the 2.03A demonstration highlighted in bold:

Table 6. Smart Inverter Working Group Functions by Phase

SIWG Phase I – Autonomous Fx *In effect 9/8/2017 (except for Volt-VAR, effective 7/25-26/18)*	**SIWG Phase II – Communications** *Will be required in 2019*	**SIWG Phase III – Advanced Fx** *Will be required in 2019*
Support anti-islanding	Utilities to DER Systems	**Monitor key DER data**
Ride-through of low/high voltage & frequency	Utilities to Facility Energy Management Systems	DER cease to energize and return to service request
Volt-VAR control through reactive power injection/absorption	**Utilities to Aggregators**	**Limit maximum real power**
Fixed power factor to inject/absorb reactive power		Set active power mode
Define default and emergency ramp rates		Frequency-Watt mode
Reconnect by "soft-start"		**Volt-Watt mode**
		Dynamic reactive current support
		Scheduling power values and modes

Field demonstrations of SIs can provide learnings that help improve inverter technologies, inform emerging industry standards, and define the operational and communication requirements to support the advancement and deployment of new inverter technologies. SI functions are becoming increasingly important for mitigating potential grid disturbances and correct for voltage and frequency dips and spikes. Defining and implementing SI control operational requirements before widespread DER penetration will also potentially avoid the future need for more costly retrofits.

[35] SIWG Phase 3 DER functions recommendations to the CPUC for Rule 21 - Phase 3 function key requirements, and additional discussion issues. http://www.energy.ca.gov/electricity_analysis/rule21/documents/phase3/SIWG_Phase_3_Working_Document_March_31_2017.pdf

3.2 Project Objectives

The overall EPIC 2.03A project objectives are:

A. Through field studies in two distinct locations, evaluate the technical ability of SIs to influence secondary and primary voltage by adjusting reactive and real power output autonomously.
B. Measure customer curtailment from Volt-VAR/Volt-Watt function activation.
C. Demonstrate and evaluate the reliability of communications to provide visibility, monitoring and change settings for SI-equipped PV using both a vendor-specific aggregation platform and a vendor-agnostic utility aggregation platform.
D. Clarify SI technology requirements to integrate and operate SIs, and characterize challenges to deployment at scale relative to today[36].
E. Through lab testing, understand SI performance under a range of distribution grid conditions.
F. Through a vendor-led modeling study, evaluate the impact of PV and PV + Storage with and without SIs and perform a cost-benefit analysis of SIs on PG&E's system as compared to traditional distribution grid upgrades.

EPIC 2.03A Location 1 activities covered in this report demonstrated SI functions' ability to mitigate potential voltage issues on the secondary using residential, customer-sited behind-the-meter (BTM) PV sites (Project Objective A – secondary voltage only). This portion of the project partnered with an aggregator vendor to deploy the SIs, which were individually monitored and managed by PG&E from June to October 2017 (Project Objective C – vendor-specific aggregation platform only, and Project Objective D).

To meet these objectives, PG&E intended to:

- Identify distribution system locations where SIs will be installed for demonstration
- Work with third-party vendor(s) to acquire customers for demonstration
- Coordinate use of field assets with EPIC 2.02, *Pilot Distributed Energy Management Systems (DERMS)*, and EPIC 2.19, *Behind-the-Meter Energy Storage*, projects.
- Demonstrate the potential of SIs to provide grid support to mitigate adverse impacts related to high penetration of customer-sited solar PV (Location 1 did not actually have high a DER penetration or related voltage issues; SI voltage support functions – Volt-VAR and Volt-Watt - were tested under normal voltage conditions)
- Evaluate field results to gain insights that better inform the distribution planning process, the interconnection process, and customer programs on potential use of SI capabilities

The EPIC 2.03A Location 1 field demonstration was completed in late 2017. Location 2 focuses on the retrofit of commercial scale PV systems with SIs to demonstrate impact on the primary (medium) voltage system and results will be released by the end of 2018.

[36] As a related objective to this SI technology demonstration and using some of the same DERs as this project, PG&E concurrently aimed to demonstrate the ability of SI-equipped PV to be monitored and dispatched remotely by a DER Management System (DERMS). For the results of this demonstration, please see the forthcoming report on EPIC Project 2.02.

3.3 Scope of Work and Project Tasks

PG&E approached the problem statement – mitigate adverse high PV penetration impact on electric grid reliability - by deploying an aggregation of third-party-owned BTM SI technologies and demonstrating the potential of aggregated BTM SI technologies to respond to electric grid conditions.

The scope of this project was to demonstrate various options to utilize distributed demand-side technologies and approaches to address local and flexible resource needs by testing through small-scale deployment.[37] These options include the SI ability to autonomously adjust active and reactive power output to mitigate voltage-related problems caused by high PV penetration.

The Location 1 activities were divided into four separate but dependent work streams:

1. **Customer Acquisition & Smart Inverter Deployment:** Support a vendor-led deployment of SIs at customer sites on identified distribution circuits
2. **Field Trial Operations:** Operate SIs, adjusting settings for functions that control SI active and reactive power output. Observe SI aggregator integration into DERMS platform
3. **Field Results Measurement & Verification (M&V):** Analyze data from the field trial to quantify the impact SIs have on local secondary voltages
4. **SI Operations:** Understand communication latency and operational challenges to interaction with SIs through a vendor-specific aggregation platform

3.3.1 Tasks and Milestones

The following are the main milestones with associated tasks and deliverables:

1. Define desired locations for SI deployment
2. Develop joint marketing approach between vendor and PG&E
3. Customer acquisition
4. Develop test cases, test plan, and M&V plan
5. Test use cases in the field and document and verify results

3.3.1.1 SI Location Selection

PG&E developed a defined strategy for selecting SI locations:

- Leverage PV adoption propensity model to target areas with favorable demographics for PV adoption and where vendors already had installations, providing opportunity for retrofits or acquisition of new customers
- Secure field trial data diversity: PV concentration, X/R ratio, ratio of diverse transformer size vs. number of customers, proximity to large PV installations, voltage regulating devices, and customer demographics (e.g., high/low income neighborhoods)

Overall, PG&E identified nine zones covering approximately 1800 PG&E customers. Among these customers, there were 200 kW of existing PV systems capacity where conventional inverters could be potentially retrofitted with SIs. Ultimately, the vendor was unable to utilize existing installations due to ownership complexities. Specifically, the majority of the vendor's already deployed systems on the

[37] http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M187/K576/187576779.PDF

feeders were not owned by customers or the vendor. Instead, these residential systems were batched and financed through large financial institutions, so one system could be owned by multiple banks. This drastically reduced the availability of retrofits because the securitized nature of system ownership prohibited reduction of system real power output, which was planned in the demonstration as part of the SI curtailment use case. As a result, the vendor targeted exclusively new customers for participation in the project. Because the vendor was also acquiring battery energy storage customers in 2.19c, they leveraged the customer acquisition for both projects.

3.3.1.2 Develop Joint Marketing Approach between Vendors and PG&E

PG&E intended to leverage its brand to help vendors market to customers. Several approaches were considered and PG&E ultimately decided on a “vendor-led, PG&E-supported” approach to customer marketing.

After the “vendor-led, PG&E-supported” approach was selected, PG&E and vendors agreed on roles and responsibilities, as presented in Table 7 below.

Table 7. PG&E and Vendor Roles and Responsibilities

	Vendor	PG&E
Planning and Development		
Create marketing plan – goals/objectives/process/timing	✓	*
Outline incentives – method and approach		✓
Develop creative – co-branded collateral	✓	*
Target Customers		
Define criteria – set geography; customer insights		✓
Identify customers – select ideal customer profiles	✓	*
Execution of Plan		
Solicit interest – initial outreach and follow-ups	✓	
Enroll in pilot – sign contract and install equipment	✓	
Ongoing engagement – periodic pilot messaging	✓	*
Close the pilot – communicate conclusion, exit survey	✓	*
Other		
Media – press release, advertorial, launch event	✓	✓
Review results – reporting, customer feedback, wrap-up	✓	*

✓ Signifies lead responsible party
* PG&E to support effort and approve plan/material.

3.3.1.3 Customer Acquisition

For the Location 1 demonstration, PG&E contracted with two vendors to conduct primary customer acquisition activities and negotiate contracts with customers. Both vendors were given deployment locations and/or zones of interest on the field demonstration feeders that would best meet the project’s objectives. These locations were provided in stages in order of priority – areas that would provide PG&E with the greatest amount of learning.

The vendors conducted all activities to install and obtain interconnection approval of BTM SI, provided an aggregation platform for PG&E to utilize for monitoring and control of BTM SI, and provided continued monitoring support throughout the technical demonstration project. PG&E Marketing provided support and approval for customer engagement approaches. The project targeted 500 kW of PV installed capacity controllable by SI. After one vendor opted out during the customer acquisition stage, the vendor that stayed on the project still believed they could acquire 500 kW of PV, but was only able to deliver 130 kW of SI controllable, residential PV capacity, of which only 62.5 kW of PV was available during the testing phase due to constrained schedules.

Because the customer acquisition rate was significantly lower than expected, PG&E expanded the desired zones. Over an approximate 5-month period, PG&E relaxed customer acquisition criteria and provided additional support to the vendor. The timeline of customer acquisition efforts was as follows:

- June 2016 - Wave 1 customer locations list provided to vendors including 200 kW of potential retrofits
- September 2016 - Wave 2 customer locations list provided to vendors; 9 specific zones / neighborhoods to target, totaling approximately 1800 customers
- October 2016 - Vendor mailers sent to all Wave 2 (~1800) customers
- November 2016 - Wave 3 customer locations list provided to vendors. PG&E allowed vendor to target all customers on two demonstration feeders (~8500 customers). Also, PG&E assisted by sending a co-branded marketing email to approximately 600 customers.

This project was co-located with EPIC 2.19C Customer-Sited and Community Behind-the-Meter Storage and EPIC 2.02 Distributed Energy Management Systems (DERMS) technology demonstration projects on distribution feeders located in San Jose, CA. All three projects shared these field resources during the field demonstration phase.

3.3.1.4 Develop Use Cases, Test Plan, and Measurement & Valuation Plan

In accordance with the project objectives, PG&E defined the following use cases:

1. Reactive Power Control Voltage Support (SIWG Phase I, Volt/VAR control)
2. Active Power Control Voltage Support (SIWG Phase III, Volt-Watt mode)
3. Remote Control (SIWG Phase II, Utilities to Aggregators & DER Systems)
4. Robust Communication (SIWG Phase II, Utilities to Aggregators & DER Systems)

These use cases sought to provide insights to the following:

- How much can BTM autonomous SI active or reactive power control impact grid voltage?
- Can Volt-Watt and Volt-VAR settings be remotely dispatched to multiple SIs?
- How robust is communication with the SIs (uptime and latency)?

Prior to operating assets in the field, PG&E developed a test plan. A detailed list of test cases is shown in Table 10 of Section 3.6 Methods. The test plan was developed to enable and allow for measurement and verification (M&V). Based on the test data available, PG&E created an M&V plan that would allow PG&E to quantify and/or qualify the vendor systems' performance. Timestamped data included active power, reactive power, and voltage measurements.

3.3.1.5 Field Trial and M&V

As part of the field trial, testing was performed on 15 out of 27 installed SIs, shared among the three EPIC projects. Results of the tests and corresponding M&V analyses are presented in Section 4, Technical Results and Observations.

3.4 Project Activities

In accordance with the use cases, the BTM SIs were tested in the field from June to October 2017. The field testing activities are described below.

- **Fixed Power Voltage Support**– SIs have the capability to set active or reactive power at a fixed (constant) output, granted sufficient SI capacity rating for fixed reactive power control and sufficient power production (e.g., PV production needs to exceed the active power level limit) for fixed active power setting. This SI capability can be used to provide voltage support. Though, to maintain voltage within limits, there may be a need to perform power flow calculations to determine the exact constant power output required to provide the desired voltage support.

  The SIWG Phase 3 autonomous SI capabilities that can provide fixed power support are shown in Table 8 below:

Table 8. SIWG Recommended SI Functions for Fixed Power Support

SI Autonomous Functions	Description	Communication Requirements
Limit maximum real power output upon a direct command from the utility- Phase 3 function.	The utility issues a direct command to limit the maximum real power output. The command might be an absolute Watt value or a percentage of SI real power output. The limit sets not-to-exceed value – real power output can be less or equal to the set limit. To achieve continuous fixed real power output, the limit must be lower than available real power behind an SI for the entire duration of the command execution.	Information and Communications Technology (ICT) infrastructure is required. Utility issues a command to limit the SI real power output.
Set actual real power output - Phase 3 function.	The utility either presets or issues a direct command to set the fixed SI real power output.	ICT infrastructure is required for utility to issue a command to modify the SI real power output.

  In accordance with the test procedure, a fixed active/reactive power output was turned on for 10 minutes (“ON interval”) and then turned off for the following 10 minutes (“OFF interval”) across all SI assets in the field, throughout the test day. By varying SI active/reactive output every 10 minutes, an average voltage change between the two intervals is an indicator of SI control effect. For both fixed active and reactive power control demonstrations, there were a total of four tests. These tests are further described in Section 3.6.

- **Dynamic Power Voltage Support** – SIs can automatically adjust active or reactive power output in response to measured voltage at the SI terminals. This SI capability allows for autonomous voltage support only when local voltage conditions meet trigger criteria. There is no need to predetermine the SI output value. The SI function to adjust active and reactive power output in response to measured voltage at the SI terminals is known as Volt-Watt and Volt-VAR function, respectively.

The SIWG Phase 3 autonomous SI capabilities that can provide dynamic power support are shown in Table 9 below**.**

Table 9. SIWG Recommended SI Functions for Dynamic Power Support

SI Autonomous Functions	Description	Communication Requirements
Provide dynamic reactive power support in response to local voltage measurements – Phase 1 Volt-VAR function.	The SI adjusts reactive power output, as available, at different voltage levels in accordance with Volt-VAR curve set points. Active power output has the priority over reactive power output – no decrease in real power output.	Autonomous local voltage monitoring. No communication requirements, unless utility updates Volt-VAR curves.
Modify real power output autonomously in response to local voltage measurements - Phase 3 Volt-Watt function.	The SI monitors the local terminal voltage and modifies real power output in accordance with the Volt-Watt settings.	Autonomous local voltage monitoring. No communication requirements, unless utility updates Volt-Watt curves.

These two tests are further described in Section 3.6 Methods.

3.5 Technical Development and Test Methods

Fifteen (15) single phase residential SI systems were deployed in the field at Location 1. As presented in Figure 1, each residential system consisted of a communication gateway, inverter, PV array, and one or two batteries. The batteries, installed to serve the need of other co-located projects, were not leveraged during the execution of this project. The SI nameplate rating was 7.6 kW and 8.35 kVA. The size of the PV array differed across the sites. The PV array and one or two batteries were connected to the same DC bus, which was connected to an SI. The inverter was connected 240 V line-to-line at the residential customer's main panel. In addition to the main panel connection, SIs were connected to a critical load panel, which supplies critical load during a power outage. In the event of a power outage the connection between the SI and main panel breaks, and the inverter operates in an islanding mode while providing service to the critical load panel.

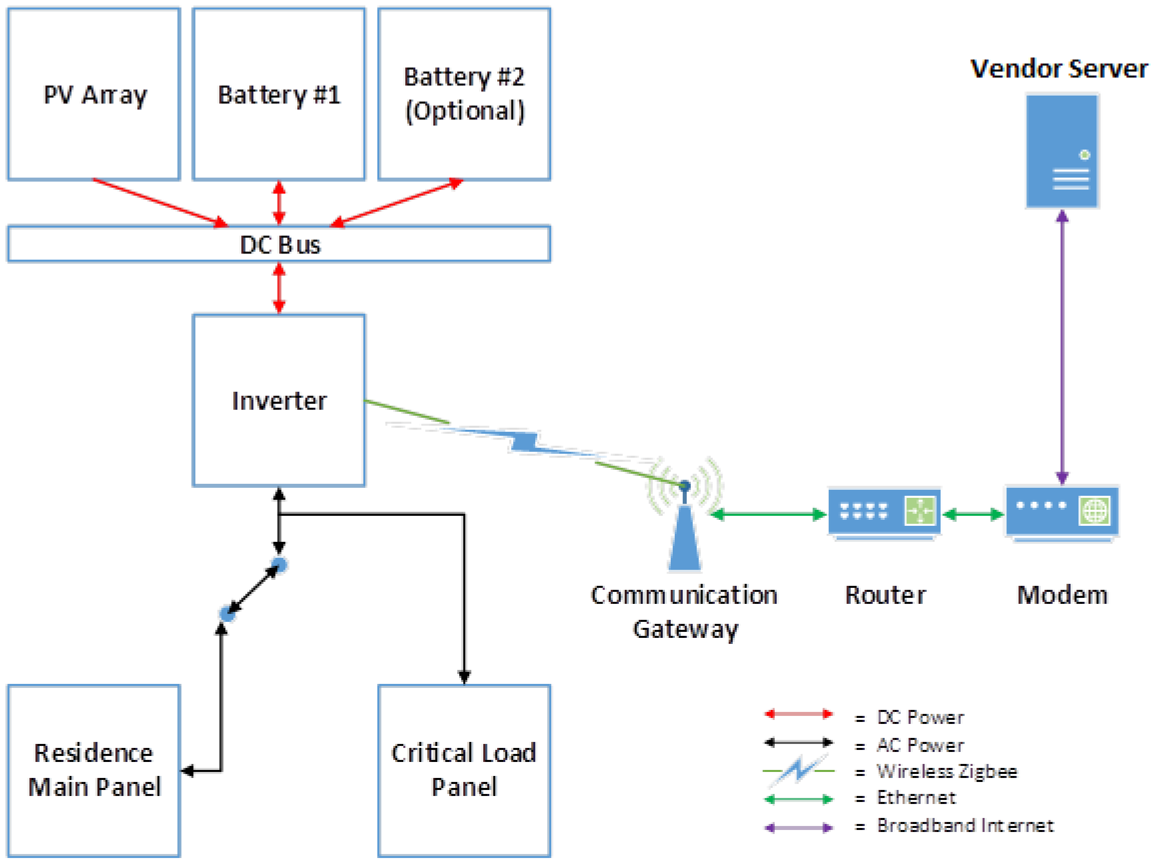

Figure 1. Residential BTM system configuration

The user interface to the SIs was a web-based application which allowed PG&E to manually issue active power limit and Volt-VAR commands in real-time or schedule commands for later execution. These commands were sent for testing purposes only and not in response to a specific grid condition (PG&E does not currently have the capability to translate grid needs into signals delivered to DERs or to aggregations of DERs). Volt-Watt function setting was scheduled on a day-ahead basis by the vendor on behalf of PG&E. Additionally, PG&E was able to schedule multiple (active power curtailment and Volt-VAR) commands through the web application by uploading a specifically formatted CSV file. PG&E had flexibility to schedule commands at the low (asset/customer) level or at higher (aggregation node) levels. There was a total of 5 levels of aggregation nodes (e.g., feeder, transformer and Point of Common Coupling (PCC)), with the highest-level accounting for all residential assets participating in the technical demonstration project. Scheduled commands at an aggregation node were re-distributed to all assets under that node and that node's sub-nodes.

The project utilized residential internet to communicate with the residential assets. The commands were sent to the communication gateway, which was connected to the residential customer's internet router by an Ethernet connection. The communication gateway stored the schedule and sent commands via Zigbee to the inverter at the command execution time.

The vendor system collected data from sites in approximately 10-second intervals. However, data (e.g., instantaneous measurements, status) reported to PG&E was in 1 minute intervals, timestamped closest to the reported minute. 1-minute interval data provided PG&E with sufficiently granular data to evaluate operation of the systems in the field. This was a field demonstration only, and not an operational requirement at production scale.

Learning: Communication infrastructure performance must improve relative to what was observed with the Location 1 assets for utilities to leverage DER remotely at scale for use cases that require active control of SIs.
Location 1 field demonstration results showed that communication uptime was not consistent and reliable across all SI assets in the field. Residential internet is generally a low-cost solution, but has significant drawbacks and may not be suitable for utility-scale programs that require direct control of assets.

3.6 Methods

A total of six tests were scoped at Location 1. Each test description and expected outcome is shown in Table 10. A list of residential assets and corresponding PV (DC side) installed capacity is shown in Table 11.

Table 10. Test Assumptions and Expected Outcomes for Location 1 testing

Test #	Test	Description	Expected Outcome
Reactive Power Control			
1	Fixed Reactive Power 2 kVAR	SI reactive power was set at 2 kVAR (import from the grid). Every 10* minutes, SI would alternate output between 2 and 0 kVAR.	Voltage at SI terminals is expected to decrease when the SI imports reactive power from the grid, following conditions when SI reactive power was set at 0 kVAR (no reactive power import).
2	Fixed Reactive Power 4 kVAR	SI reactive power was set at 4 kVAR (import from the grid). Every 10* minutes, SI would alternate output between 4 and 0 kVAR.	Same as in Test #1.
3	Volt-VAR (dynamic reactive power control)	Evaluated SI ability to automatically adjust reactive power output in response to measured voltage at the SI terminals. Previous day voltage observations were used to determine custom Volt-VAR curve set points at each SI to be executed on the test day. Set points were selected so SI response results in some reactive power output (kVAR) change due to change in SI terminal voltage.	In accordance with the Volt-VAR curve shape, SI adjusts reactive power output in response to measured voltage at the SI terminals.
Active Power Control			

Test #	Test	Description	Expected Outcome
4	Fixed Active Power 1 kW	SI active power was set at 1 kW. Every 10* minutes, SI would alternate active power output between 1 and 0 kW. At all times, reactive power output was set at 0 kVAR.	Voltage at SI terminal, PCC and service transformer secondary side terminals is expected to decrease when SI active power reduces to 0 kW (no export – larger net load demand).
5	Fixed Active Power 2 kW	For PV systems producing more than 2 kW, SI active power was set at 2 kW. Every 10* minutes, SI would alternate active power output between 2 and 0 kW. At all times, reactive power output was set at 0 kVAR.	Same as in Test #3.
6	Volt-Watt (dynamic active power control)	Evaluated SI ability to automatically adjust SI active power output in response to measured voltage at the SI terminals. Previous day voltage observations were used to determine custom Volt-Watt curve set points at each SI to be executed on the test day. Set points were selected so SI response results in some active power output (kW) change due to change in SI terminal voltage.	In accordance with the Volt-Watt curve shape, SI adjusts active power output in response to measured voltage at the SI terminals.

* During consecutive command on and off time intervals, the assumption was that neither PV active power production nor secondary system aggregate load changed significantly between the two 10 min periods. Accordingly, the magnitude of voltage change between the two intervals was interpreted as the result of the SI commands.

Table 11. Residential BTM Solar PV Site List

Asset	DC Solar Size (kW)
SI_A	3.92
SI_B	4.16
SI_C	3.38
SI_D	3.12
SI_E	2.60
SI_F	2.60
SI_G	3.38
SI_H	6.24
SI_I	8.19
SI_J	2.86
SI_K	4.24
SI_L	4.93
SI_M	5.22
SI_N	6.24
SI_O	4.16

An example of a Volt-VAR curve is shown in Figure 2. The SI measures voltage at the terminal, then adjusts the reactive power output according to the Volt-VAR curve set points. The fixed reactive power import of 2 or 4 kVAR was implemented via Volt-VAR curve by implementing settings that guarantee the desired constant power output in the range of operating voltages expected in the field conditions. Actual Volt-VAR curves used are shown in Figure 7 and Figure 8 (Section 4.1.2). Every time the SI enabled Volt-VAR functions (every 10 min), the SI reactive power output was constant at the specified value (e.g., import 4 kVAR).

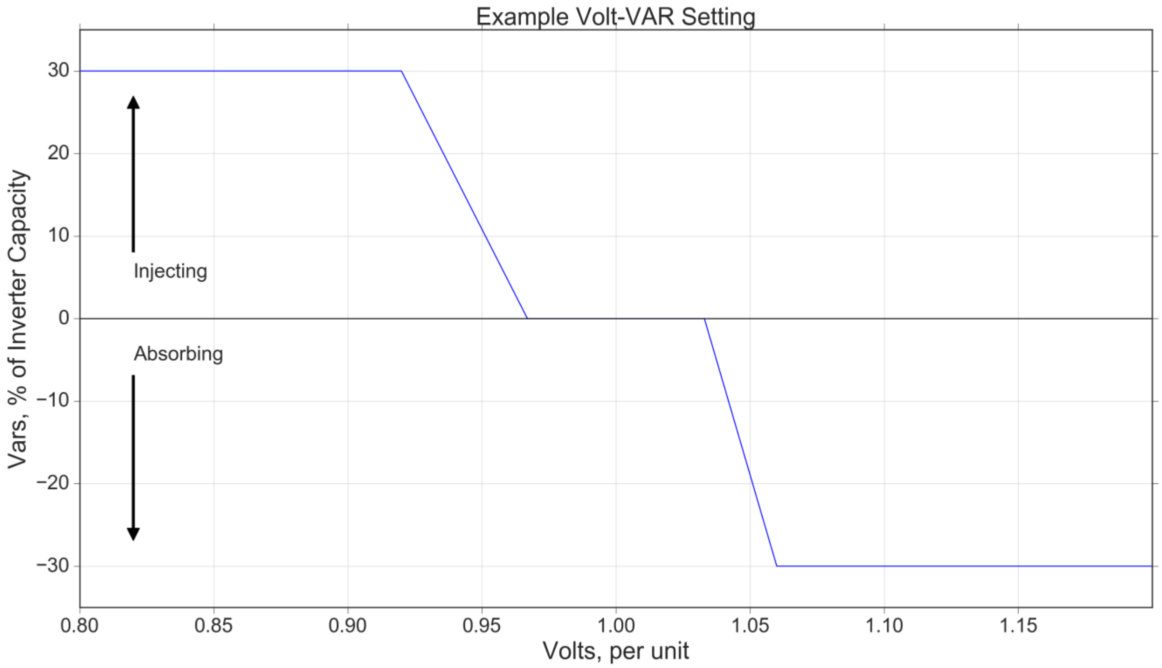

Figure 2. Volt-VAR Curve

The fixed active power export of 1 or 2 kW was implemented via curtailment command. The dynamic active power control was implemented via Volt-Watt curve. An example of Volt-Watt curve is shown in Figure 3. The SI measures voltage at the terminal, then adjusts the active power output according to the Volt-VAR curve set points. During field testing, Volt-Wat curve set points were chosen to guaranty desired constant power output at range of operating voltages expected in the field conditions. Every time the SI enables Volt-Watt function (every 10 min), the SI active power output was constant at specified value (e.g., 2 kW).

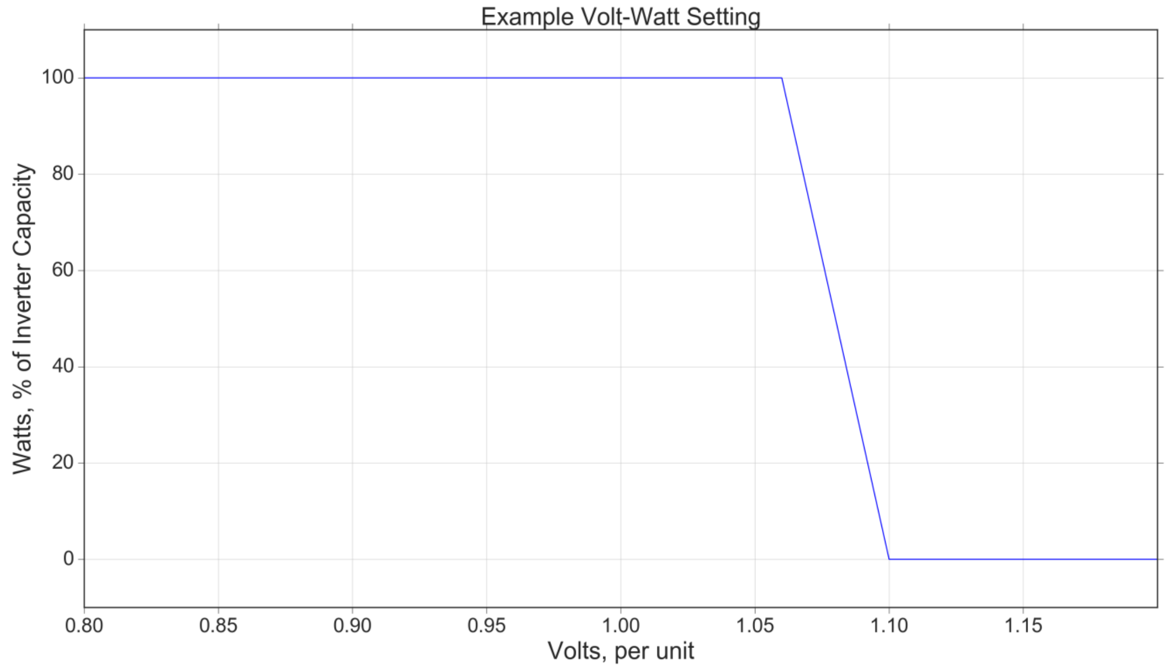

Figure 3. Example Volt-Watt Curve Setting

3.7 Challenges

The main challenges encountered by the EPIC 2.03A project can be grouped as follows:

- Customer Acquisition
- Asset Commissioning & Site Acceptance Testing
- Volt-Watt Setting Procedure
- Priority of SI Functions

3.7.1 Customer Acquisition

PG&E was ultimately surprised that the biggest project challenge was getting assets into the field, which resulted in project delays. Despite their best efforts, vendors had a difficult time acquiring customers, delivering only 130 kW of SI controllable PV capacity, but only 62.5 kW of testable capacity due to delays in deploying the technology in the field.

There were approximately 200 kW of existing PV systems in the targeted areas that PG&E expected to be retrofitted with SIs. Because the vendor transferred ownership for most of these systems to 3rd parties, the vendor had difficulties obtaining permission from 3rd party owners to curtail active power due to contractual obligations to maintain full PV production output. Thus, retrofits were not pursued at the sites where active power control (curtailment) was not feasible. In addition, the vendor faced difficulties acquiring new customers to participate in the technology demonstration, despite an incentive in the form of a $300 credit and a free residential energy storage device.

After the customer acquisition stage was closed, PG&E learned that the vendor acquired some customers in targeted zones during the customer acquisition period who did not end up participating in the field demonstration. This was a surprising but valuable learning for both parties.

Learning – Identify and account for customer acquisition risks
There are many reasons why customer acquisition was challenging for the San Jose DER technical demonstration projects. The key reasons include: limited access to customer information, customer fatigue from door-to-door solar, and existing solar system ownership structure and restrictions on testing rights. This part of the project highlighted that customer acquisition risks should be accounted for to establish more realistic deployment timelines, particularly in situations where targeted deployment would be required for safe operation of the grid (e.g. as part of a non-wires alternative PV + storage capacity project).

Learning – Ownership rights may prevent retrofits
The Location 1 demonstration explored the possibility of retrofitting existing, conventional inverters with SIs. Often, residential PV systems aren't owned by the customers or DER vendors, but by 3rd parties. Since 3rd party ownership rights typically prevent any possibility to intentionally curtail power, which was part of the active power control use case, most existing inverters on the demonstration's electrical feeders could not be retrofitted with SIs. Because residential systems make up the bulk of the existing PV customer base, DER technology demonstration projects that rely on residential system retrofits to achieve a certain penetration level may be challenged if 3rd party ownership rights prohibit activities required by the project.

3.7.2 Asset Commissioning & Site Acceptance Testing

Once assets in the field have gone through final PG&E inspections and receive permission to operate (PTO), two commissioning steps take place before systems can participate in field demonstrations: (1) vendor commissioning to verify SI readiness for PG&E site acceptance testing and (2) PG&E site acceptance testing to verify SI readiness for use case demonstration. Both activities should have been a simple 'check-list' process, but have proven to be challenging and led to longer than anticipated timelines.

During the commissioning process, both the vendor and PG&E identified issues that prevented the SIs from functioning as intended. Further, tests that passed for the vendor often failed for PG&E – exposing communication and technology reliability problems prior to the demonstration. Examples of issues caught by PG&E that should have been resolved by the vendor prior to asset handover included upgrade of communication gateway firmware, configuration of a unique PAN ID for the site's assets to ensure isolation from neighboring Zigbee networks, and verification of communication uptime.

Learning – More testing is needed by vendors before assets turned over for acceptance testing
In general, after customer acquisition, commissioning of assets in the field was the most challenging aspect of the project. This suggests that vendor systems needed more testing by vendors before being handed over to PG&E for the site acceptance testing.

3.7.3 Volt-Watt Setting Process

Custom Volt-Watt curves were uploaded to individual SIs by vendor staff on PG&E request the day before the test. This was not only time-consuming but also limited PG&E's ability to adjust the settings in near real-time based on voltage conditions in the field during testing. The reason for using custom Volt-Watt curves was to force SIs to perform as if SIs were experiencing voltage conditions outside of Rule 2 limits, since voltages on the field demonstration feeder were within Rule 2 limits. In autonomous SI applications, Volt-Watt and Volt-VAR curve set points are not expected to change frequently, if at all, and would be pre-loaded onto SIs by manufacturers in compliance with Rule 21 standards and allowed to run independent of any additional, external active control signals.

3.7.3.1 Priority of Functions

When scheduled, Volt-VAR and Volt-Watt curves both ran continuously and autonomously adjusted reactive and active power in accordance with the curve settings as dictated by voltage readings measured at the SI terminals. If a limit of real power (active power curtailment) was put in place that was lower than what the power would be given the DC generation and the Volt-Watt curve, then that limit was adhered too. If that limit was higher than what the output would be otherwise, it had no effect.

4 TECHNICAL RESULTS AND OBSERVATIONS

In collaboration with the vendor, PG&E successfully completed 6 tests. Grouped by the use case, the sections below describe the tests, test results, takeaways, and next steps.

4.1 Reactive Power Control Voltage Support

This section summarizes the test results that correspond to Use Case #1: Reactive Power Control Voltage Support. This use case addressed one of the key objectives of this project – use of SI reactive power import/export capability to provide local voltage support.

4.1.1 Fixed Reactive Power

The fixed reactive power tests were executed on multiple assets with each test series performed over multiple days. As shown in Figure 4, SI reactive power output changed from a pre-set value to zero every 10 minutes. On different test days, two tests were executed with pre-set fixed reactive power set points at 2 and 4 kVAR. When reactive power was negative, the SI absorbed (imported) VARs from the grid; that is, the SI acted as an inductive element.

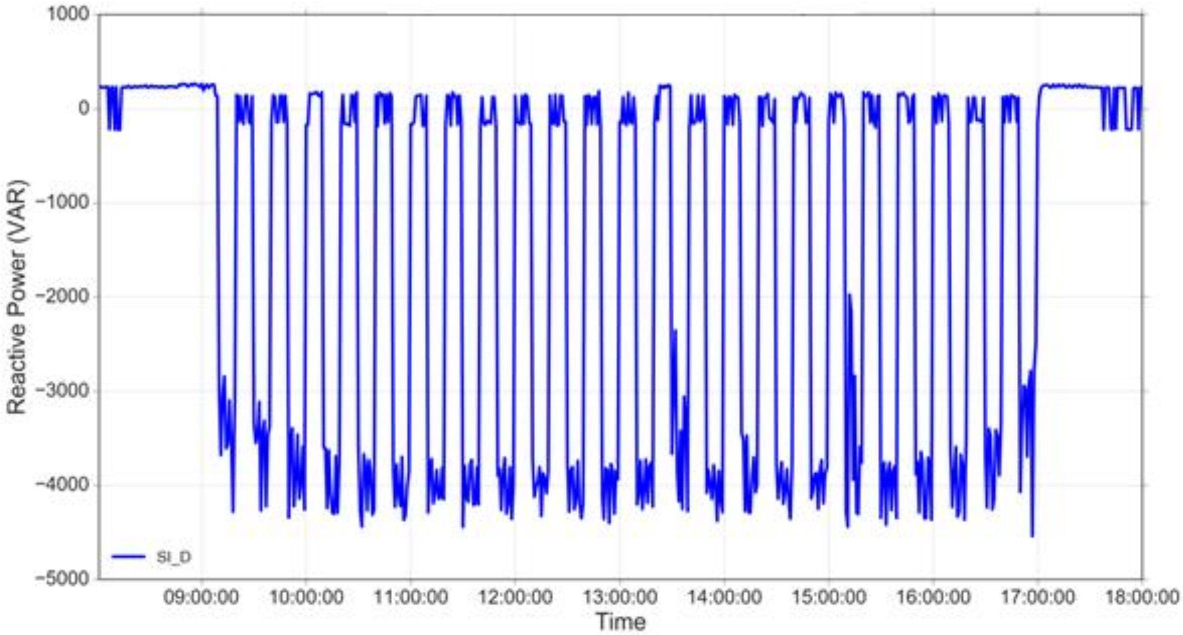

Figure 4. Reactive Power Import Cycling from -4 to 0 kVAR

Reactive power cycling (from a fixed non-zero to zero VARs) every 10 minutes enabled comparison of average voltage measurements between the two 10 minute intervals. The 10-minute interval was chosen to allow capture of sufficient amount of measurements but also to result in minor, if any, changes in net-load between the two 10 minute intervals. As expected, voltage at the SI terminals drops as more reactive power is imported from the grid (absorbed by the SI). Figure 5 shows how the SI terminal voltage changed with the change in reactive power absorbed by the SI. This graph demonstrates that local (SI terminal) voltage can be influenced by changing the SI reactive power – one of the project key objectives.

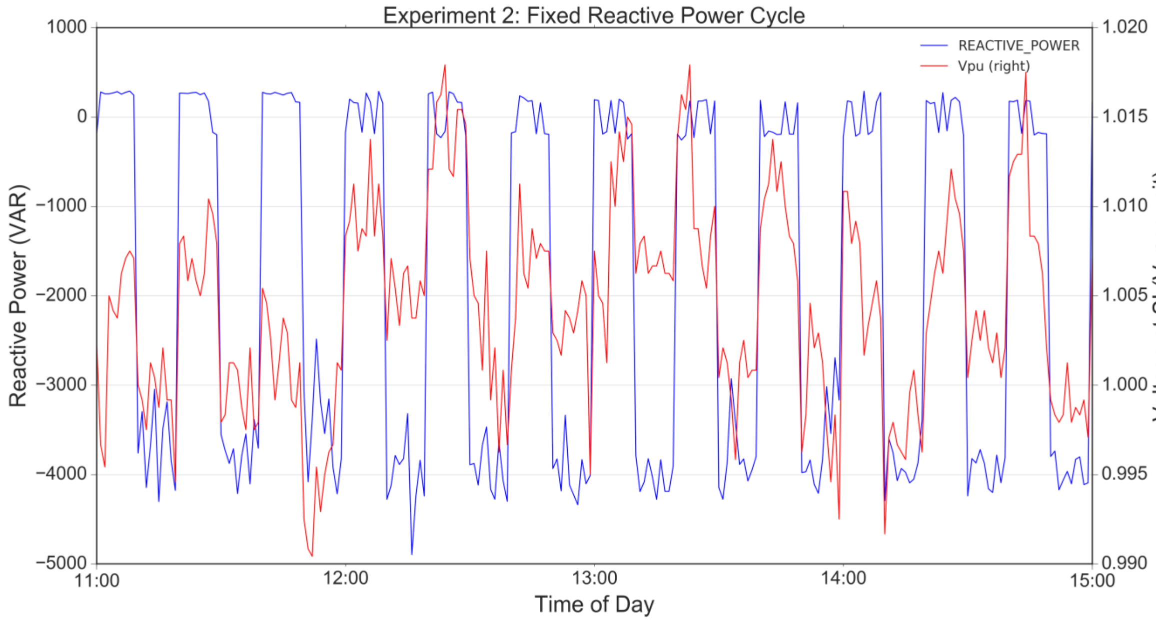

Figure 5. SI Terminal Voltage Change with Change in Reactive Power Support

The field results show that on average SI import of 2 kVAR of reactive power lowered the voltage at SI terminals by 0.5V. SI terminal voltage measurements when the SI imported 0, 2 and 4 kVAR is shown in Figure 6.

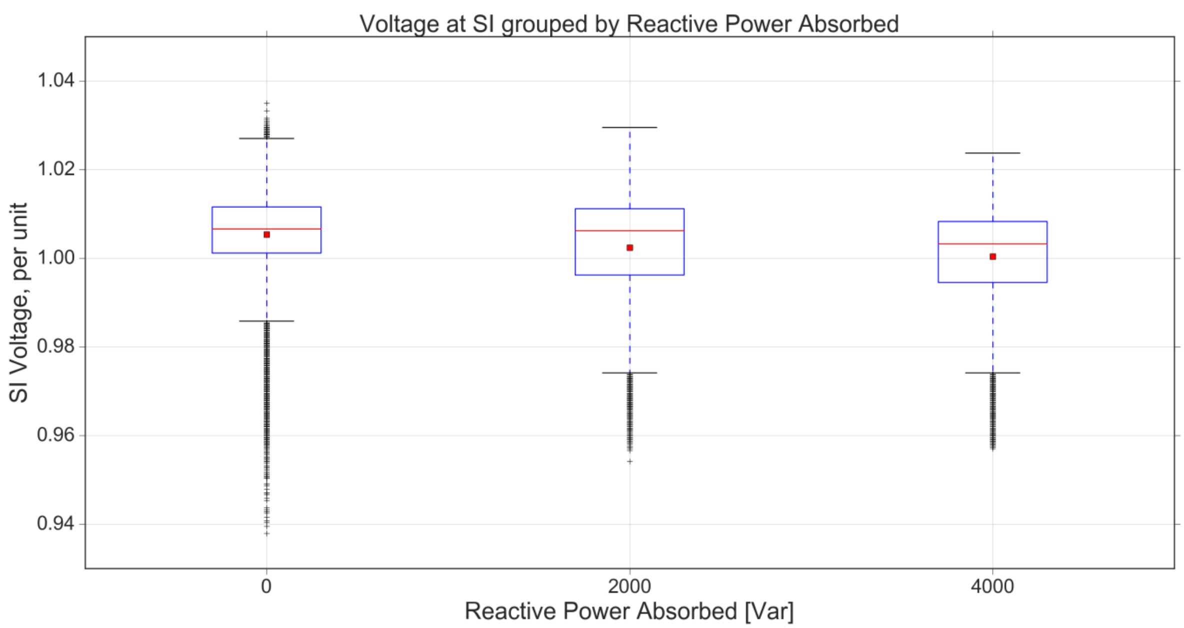

Figure 6. SI Terminal Voltage at Different kVAR Import Levels

Learning – SI reactive power can help with voltage regulation in low voltage systems
Both SI and PQM measurements show that SI reactive power support can help voltage regulation at the PCC and across the secondary (low voltage) system. The extent to which SI reactive power support can affect the secondary voltage depends on the amount of reactive power and secondary system electrical properties and load conditions. The field demonstration test results show that on average, 1 kVAR of reactive power support results in a 0.25 V change at the SI terminal. Although some voltage support was observed, the low capacity of SI assets included in the field demonstration prevented a more accurate assessment of SI impact on secondary system voltage. Greater SI capacity would be needed to more accurately assess the SI impact.

4.1.2 Volt-VAR

Custom Volt-VAR curves were set for each SI. Because the technology demonstration feeders had no voltage violations (or reverse flow conditions), customized Volt-VAR curves were set to allow the SIs to provide reactive power support under the normal voltage conditions experienced in the field. The field demonstration results show that the SIs successfully adjusted their reactive power support in accordance with these Volt-VAR curve shapes. Figure 7 and Figure 8 show two different SI Volt-VAR test results, indicating SI capability to largely follow the curve shape with some SI reactive power outputs outside the expected +/- 250 VAR threshold. Each data point in these two figures represents an instantaneous reactive power measurement, timestamped closest to the beginning of a minute interval.

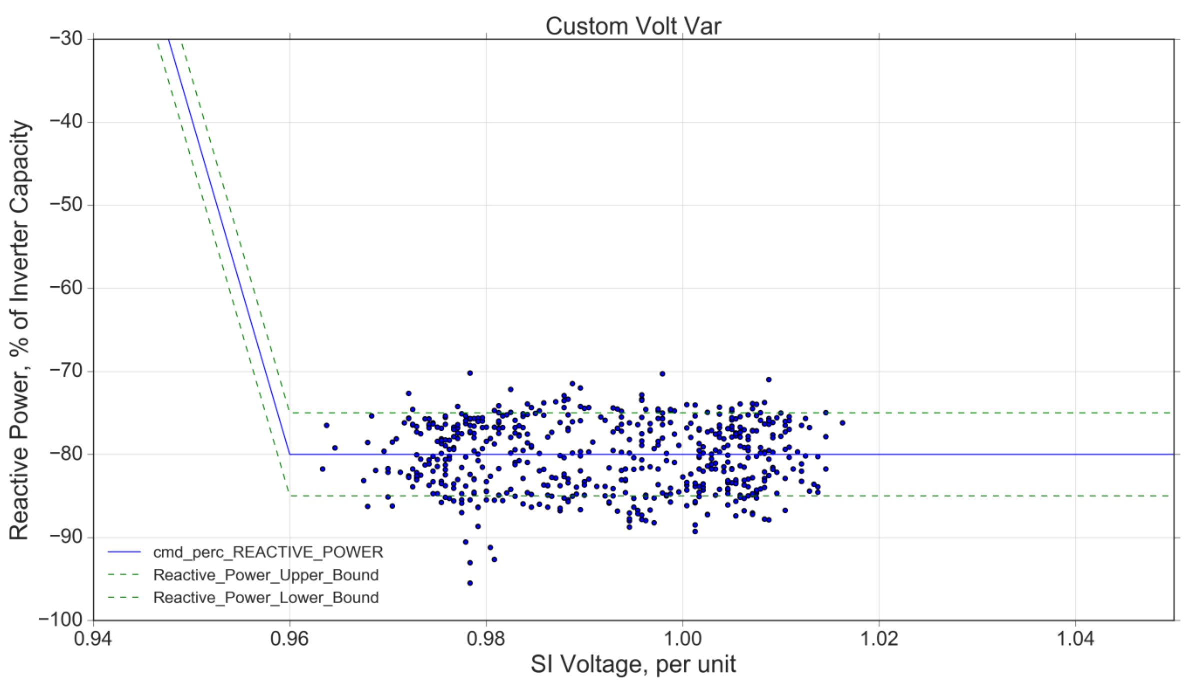

Figure 7. Custom Volt-VAR - Test 1

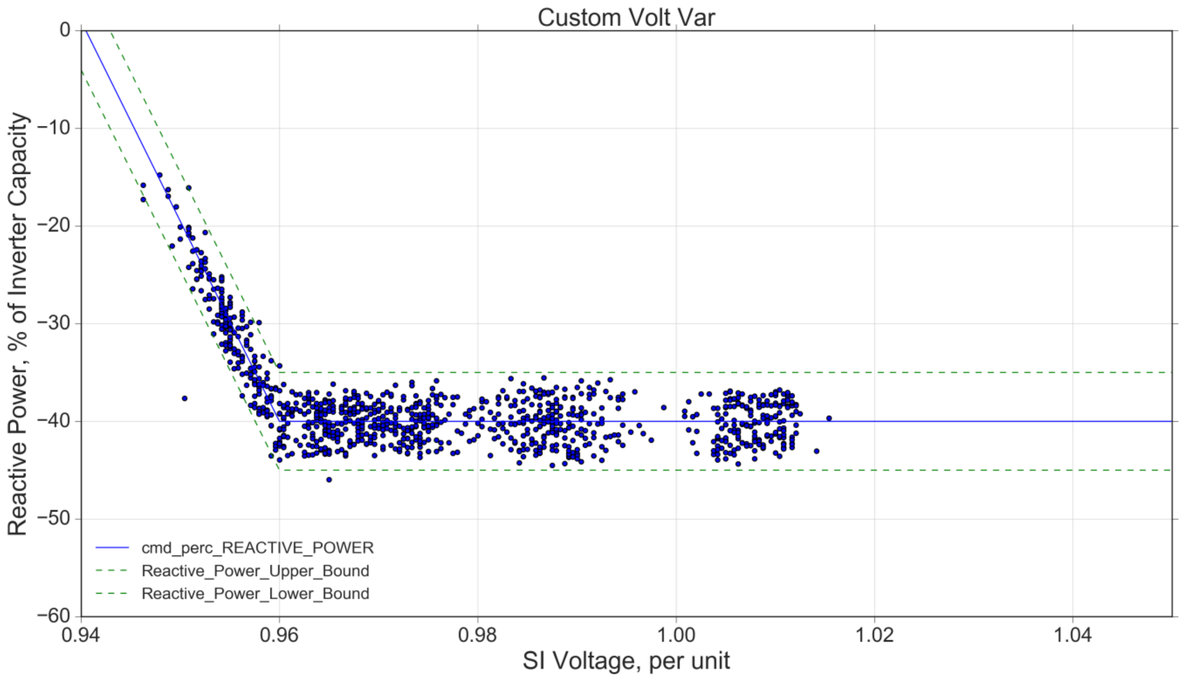

Figure 8. Custom Volt-VAR - Test 2

Learning – SIs executed Volt-VAR functions as programmed

The vendor's monitoring and control (M&C) platform allowed for simultaneous dispatch of Volt-VAR curves to multiple SIs. Overall, SIs were able to provide reactive power support in accordance with the assigned Volt-VAR curve. However, there were instances when reactive power support was outside of the expected +/- 250 VAR threshold. These may be attributable to measurement errors or the SI algorithm that dictates the level of reactive power injection/absorption in response to voltage fluctuations.

Further analysis indicated that spikes in reactive power were coincident with spikes observed in active power, which may have caused the reactive power to fall outside of the tolerance bands. Figure 9 shows an example with the circled data points highlighting this interaction. As active power spiked up, reactive power spiked down outside of the tolerance bands. As active power spiked down, reactive power spiked up outside of the tolerance bands.

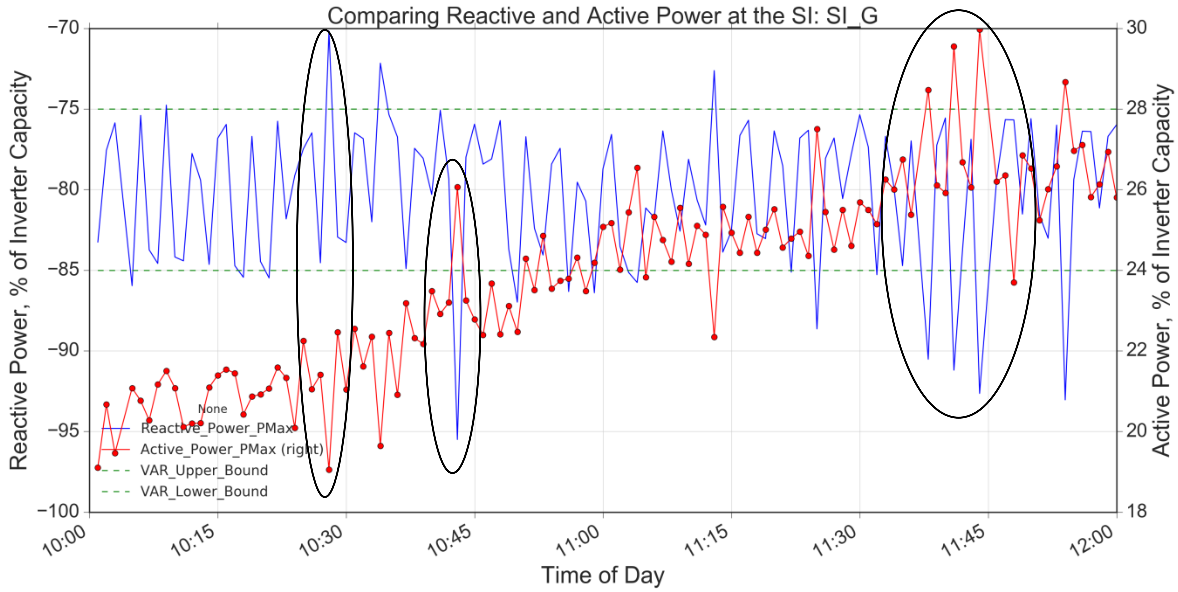

Figure 9. Reactive and Active Power (% of Max) overlaid to show interactions

4.2 Active Power Control Voltage Support

This section summarizes the test results that correspond to Use Case #2: Active Power Control Voltage Support. This use case addresses one of the key secondary objectives of this project – the use of SI active power import/export capability to provide local voltage support.

4.2.1 Fixed Active Power

The fixed active power tests were executed on multiple assets with each test series performed over multiple days. As shown in Figure 10, SI active power output changed from a pre-set value to zero every 10 minutes. On different test days, two tests were executed with pre-set fixed active power limit set points of 1 and 2 kW.

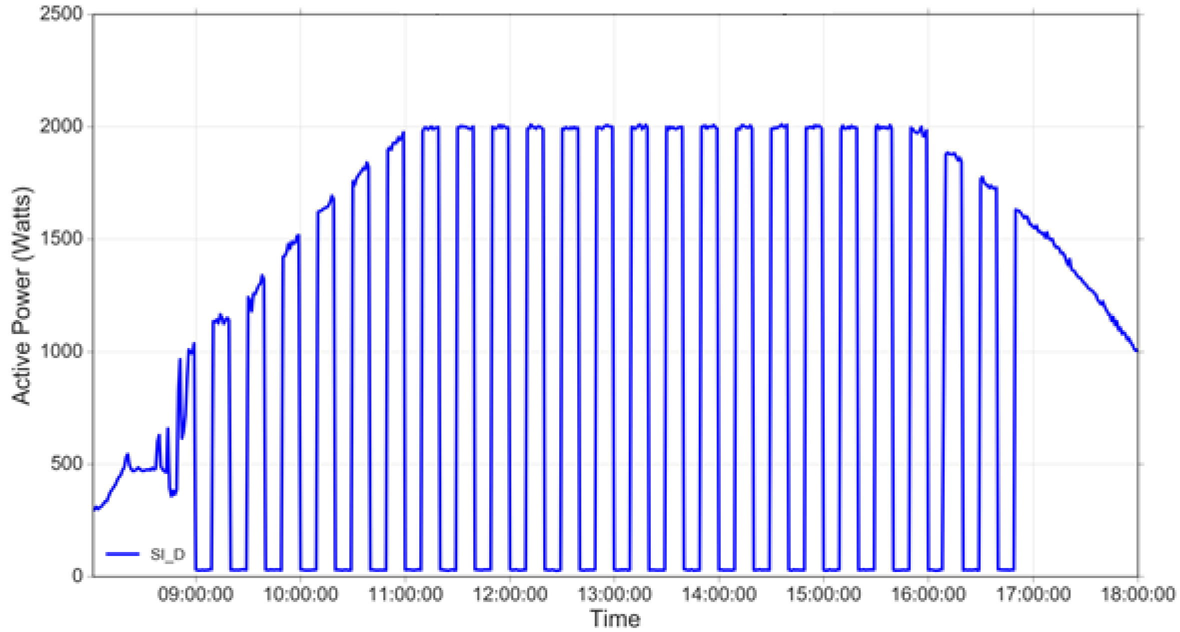

Figure 10. Active Power Cycling Limited to 2kW Export

Identical to the fixed reactive power test, active power cycling (from a fixed non-zero to zero kW) every 10 minutes enabled comparison of average voltage measurements between the two 10 minute intervals. As expected, voltage at the SI terminals rose as more active power was exported to the grid. Figure 11 shows how the SI terminal voltage changed with changes in active power exported by the SI. This graph shows that the project achieved its objective of demonstrating that local (SI terminal) voltage can be changed by changing SI active power.

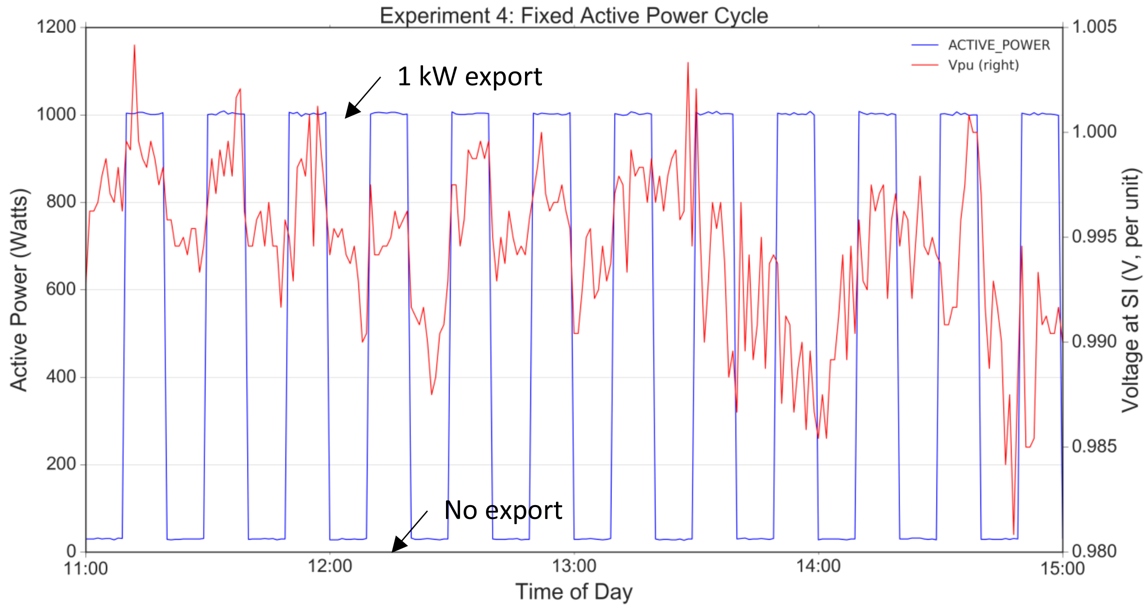

Figure 11. SI Terminal Voltage Change with Change in Active Power

Figure 12 shows the effect of active power export on voltage measured at the SI terminals. As expected, voltage at the SI terminals rose as more active power was exported to the grid. On average, 1kW and 2 kW of active power export raised SI voltage by 0.6 V and 1 V, respectively.

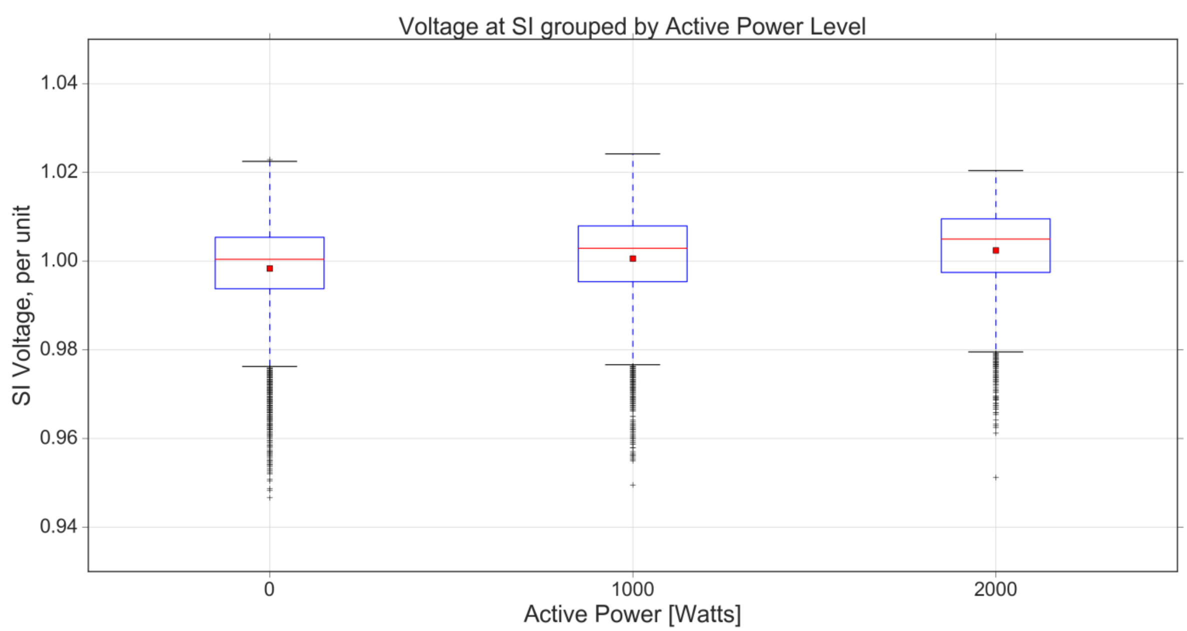

Figure 12. Voltage at SI Terminals at Different Active Power Export Levels

Learning – SI active power can help with voltage regulation in low voltage systems

SI measurements show that SI active power curtailment can help voltage regulation at the SI terminal location. The extent to which SI active power curtailment can affect the secondary voltage depends on the amount of controllable active power and secondary system electrical properties and load conditions. The field demonstration test results show that on average, 1 kW of active power support has an impact of 0.5 V at the SI terminal location.

4.2.2 Volt-Watt

Custom Volt-Watt curves were set for each SI. The field demonstration results show that the SIs successfully adjusted active power support in accordance with the Volt-Watt curve shape. Figure 13 and Figure 14 show a sample of SI Volt-Watt test results, indicating that the SIs were largely able to follow the curve shape.

It is important to note that the SIs used in this technology demonstration were not UL certified to comply with UL 1741 SA requirements because manufacturers were not yet required to comply with this standard at the start of the demonstration. The SI firmware used in the demonstration was the result of SI vendor R&D development efforts to enable PG&E to execute this use case.

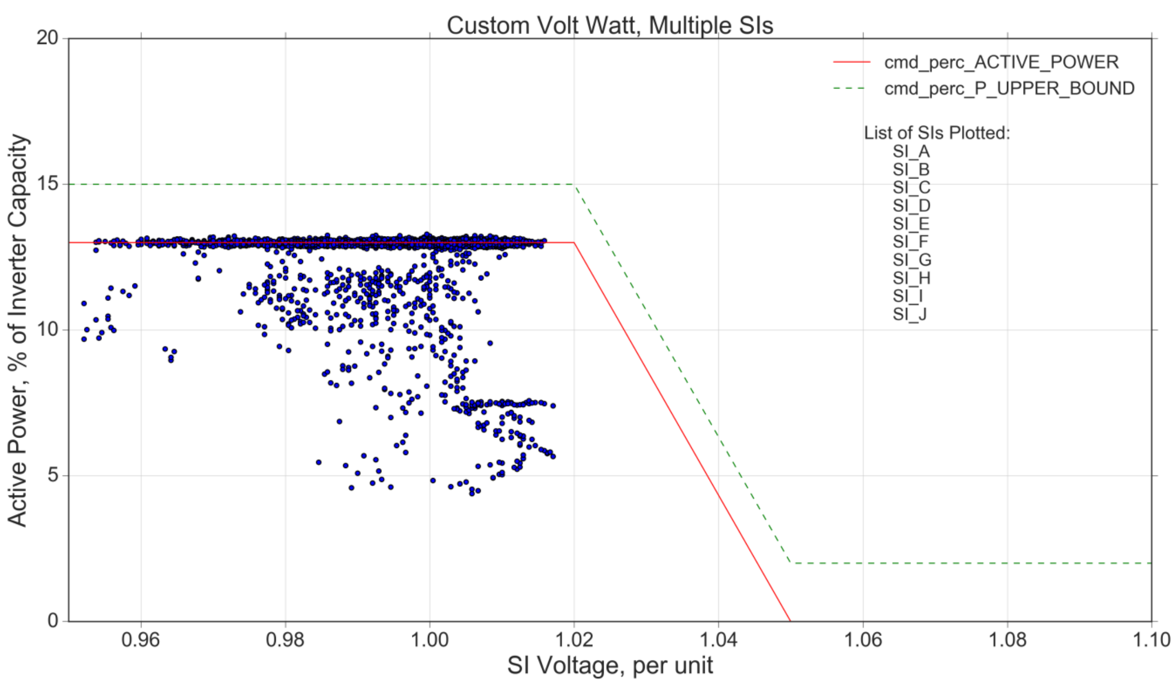

Figure 13. Custom Volt-Watt Function Execution on Multiple SIs

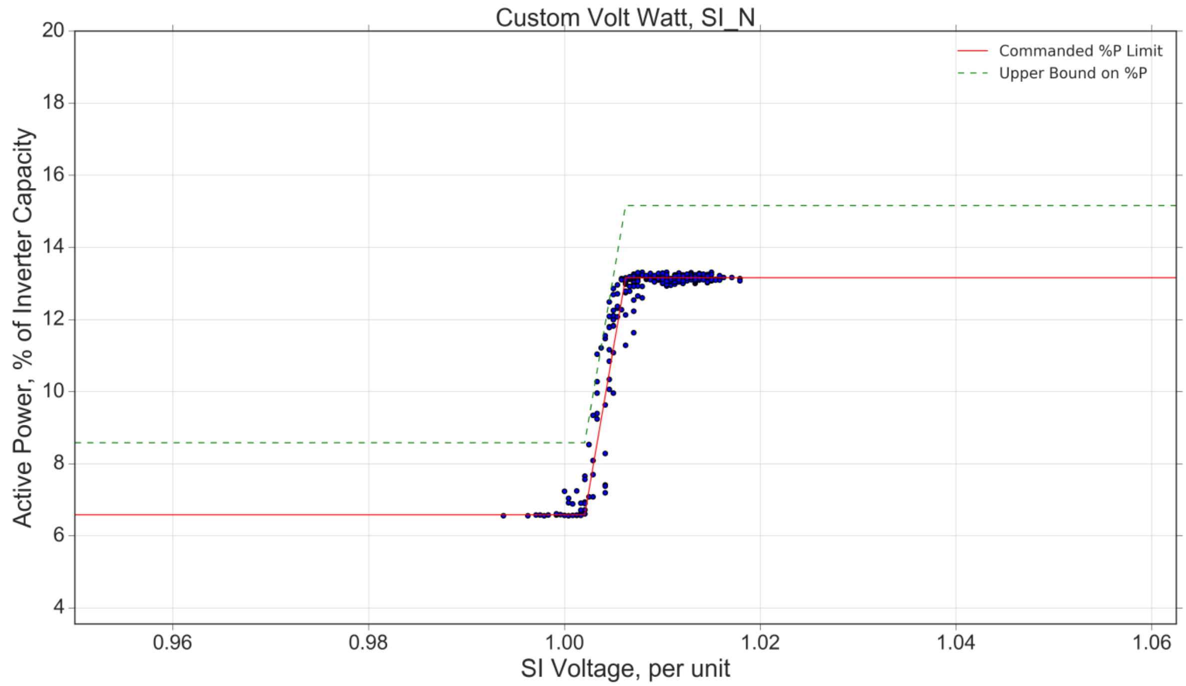

Figure 14. Custom Volt-Watt Function Execution on SI_N

In addition to the custom Volt-Watt curve, active power curtailment commands were sent for a 1 hour period between 14:00 and 15:00.

Learning – Volt-Watt functions executed as programmed when no other active power control commands were executed.
Once scheduled, SIs were able to follow a Volt-Watt curve, except at times when Volt-Watt was enabled and the active power curtailment command was cycling on and off. In those instances, Volt-Watt stopped executing for a short period of time (30 min). This outcome is specific to the SI manufacturer whose SIs were used in the field demonstration and the custom firmware that was specifically developed for it. To ensure reliable performance when SIWG Phase 3 functions become mandatory in CA, Volt-Watt function execution in combination with other functions should be further tested and certified by SI manufacturers.

4.3 Remote Control

This section summarizes the test results that correspond to Use Case #3: Remote Control, and explored the vendor's capability to remotely dispatch autonomous Fixed Power Factor, Active Power Limit (Curtailment), Volt-Watt and Volt-VAR settings to multiple SIs. The web application used by PG&E to monitor and control SIs in the field allowed only for Fixed Power Factor, Active Power Limit and Volt-VAR functions to be remotely dispatched. For Volt-Watt, PG&E submitted set points to the vendor on a day-ahead basis, and the vendor dispatched those settings accordingly. The user interface to the SIs was a vendor run and hosted web application. For commands that were dispatch-able via the web application, PG&E was able to issue commands in real-time or schedule execution of commands in future either as a single command or as a recurring command. Most of the time, multiple commands were uploaded in bulk through the web application with a specifically formatted CSV file, specifying the SI functions to be executed, set points, and the start and duration of an event.

Learning – Bulk upload of CSV schedules on the SIs can cause a high Central Processing Unit (CPU) load on the gateways, resulting in temporary loss of communication.

The dispatch of Volt-Watt curves required ad hoc vendor assistance, as the vendor-utility SI aggregation interface was not set up at the project outset for PG&E to change Volt-Watt settings directly. PG&E provided individual SI Volt-Watt curve settings to the vendor the day before the test execution, and the vendor “pushed” those settings to individual SI assets in the field. While autonomous SI Volt-Watt/Volt-VAR settings are not likely to be changed frequently once implemented (and would likely be pre-loaded onto SIs by manufacturers prior to SI installation), the ability to remotely change settings in real time may be required for on-demand or active SI use cases. More streamlined remote function-setting may be possible with advances since the time of testing at Location 1 of this project.

Learning – Capability to more efficiently upload Volt-Watt settings remotely may be needed for on-demand or real-time SI use cases.

4.4 Communication

Learning – Reliable communication links are critical for success. Communication infrastructure performance must improve relative to what was observed in this project for use cases that require real time active control at scale.

This section summarizes the test results that correspond to Use Case #4: Robust Communication. The test evaluated the vendor’s system communication performance during testing.

Communication uptime was analyzed by comparing the reported “Online” and “Offline” time periods for every asset in the field. The communication uptime graphs are presented in Figure 15 and Figure 16. The results show that communication uptime was greater than 95%, for 85% of test days. The histogram graph (Figure 15) shows that 65% of the time the communication uptime was 99% to 100%. The cumulative distribution function shows the same information in another way - the probability of communication uptime being less than 95% was 15%. However, Figure 16 shows the inconsistencies that occurred in bringing the assets online. Ultimately, most assets reached a reliable uptime steady-state, but there were significant implementation challenges to get to this point.

As can be seen in Figure 17, SI_C had poor uptime performance from the commissioning date, and stopped communicating entirely on 8-31-17. The gateway was replaced on 9-14-17 and the communication uptime improved significantly. Another measure was taken to improve communication uptime during the testing period. The data polling frequency was reduced from approximately 10 seconds to 3 minutes for asset SI_H from 9-2-17 to 9-7-17. This test showed that the uptime of this asset improved. The reduced polling frequency was permanently applied to assets SI_H and SI_C on 9-27-17. The impact of reducing polling frequency can be seen in Figure 17.

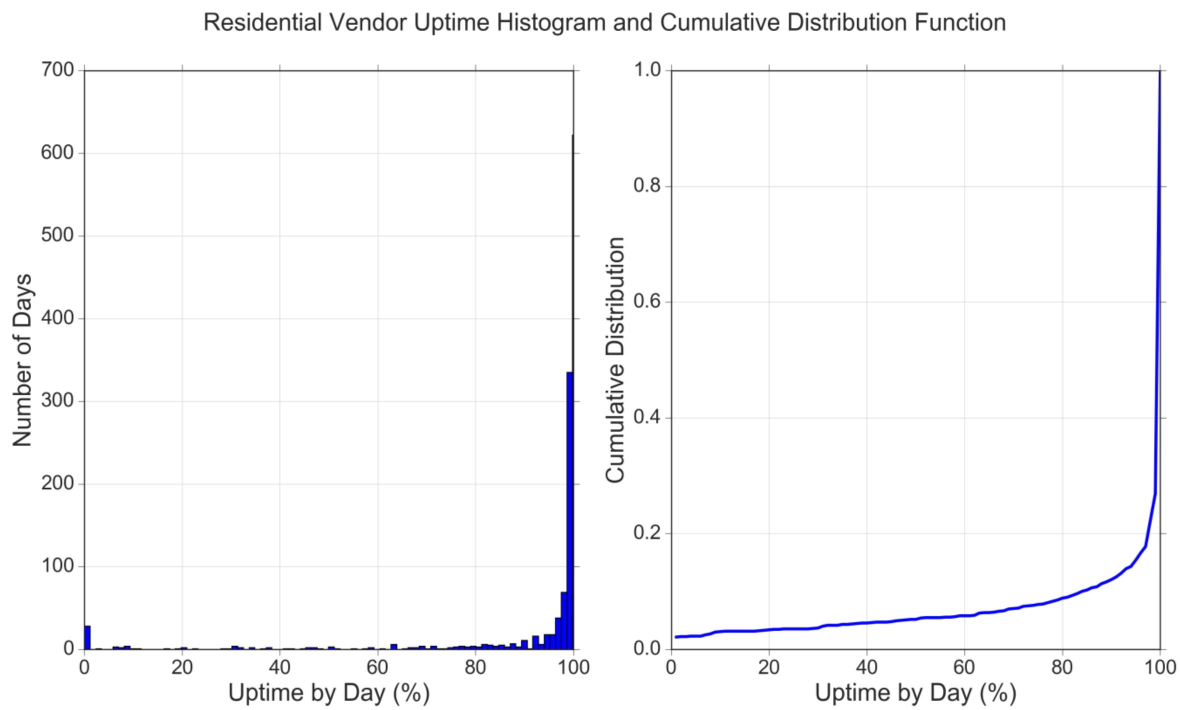

Figure 15. Communication Uptime Histogram and Cumulative Distribution Function

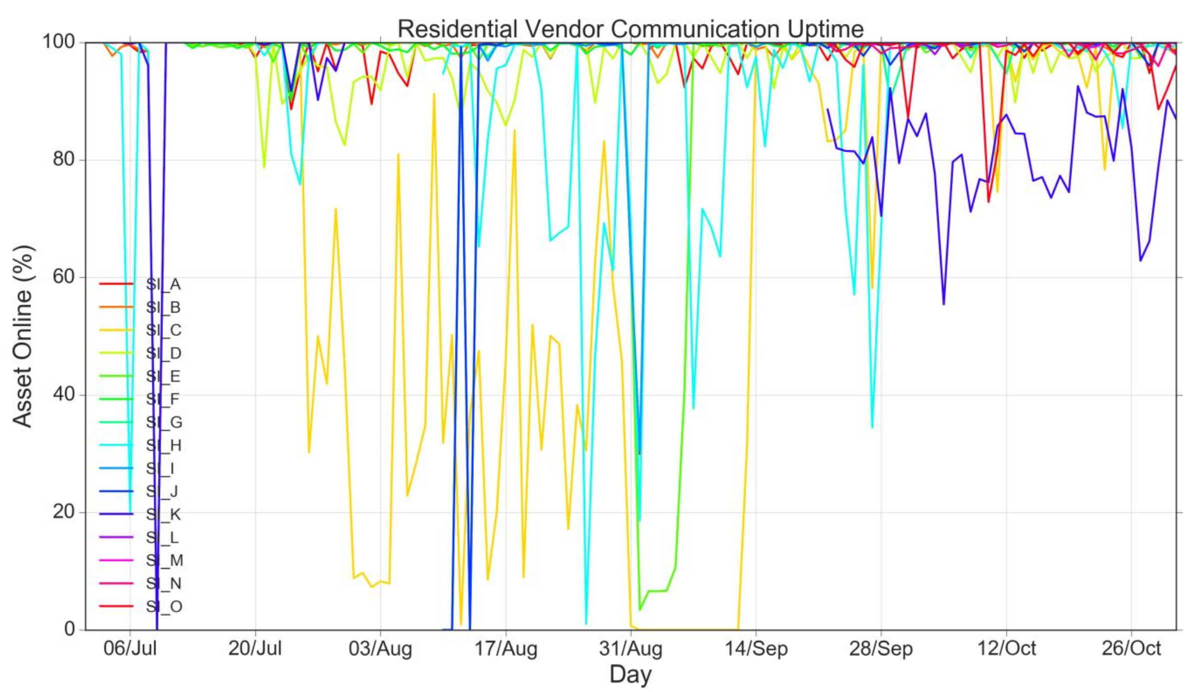

Figure 16. Communication Uptime Online Performance from 7/1/17 to 10/31/17

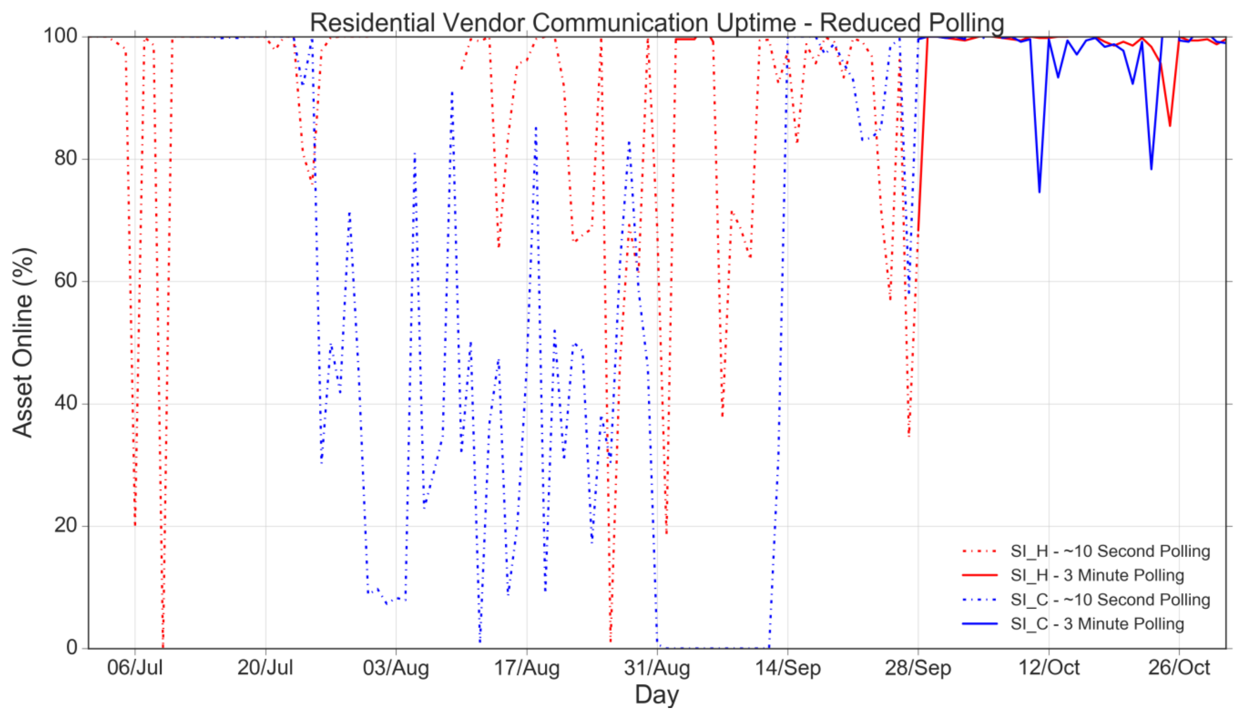

Figure 17. Impact of Reduced Polling on Communication Uptime

The vendor's user interface displays real-time data for each individual asset, which is based on a polling frequency of approximately once every 10 seconds. The UI can be used to measure latency by comparing the time of command execution versus the time of observed execution on the asset.

Table 12 and Figure 18 show the data gathered for the latency tests. Multiple smart inverters were commanded to execute different SI settings over the course of the day, and the latency was measured. 29 latency measurements were taken. The maximum latency observed was 18.0 seconds, and the average latency observed was 8.6 seconds. This round-trip command latency performance is within the 30 second maximum SCADA response time before a communication error is incurred. The data indicates that the time of day and the specific SI setting executed did not influence latency.

Table 12. Latency Measurements

Asset	Test Time	SI Setting Executed	Latency (sec)
SI_G	08:26	Curtail	5
SI_B	08:27	Curtail	4
SI_O	08:28	Curtail	10
SI_D	08:29	Curtail	10
SI_N	08:30	Curtail	7
SI_G	10:54	Curtail	7
SI_B	10:55	Volt-VAR	6
SI_O	10:56	Volt-VAR	11

Asset	Test Time	SI Setting Executed	Latency (sec)
SI_D	10:57	Curtail	9
SI_K	10:58	Volt-VAR	10
SI_N	10:59	Volt-VAR	6
SI_G	12:26	Curtail	11
SI_B	12:27	Volt-VAR	12
SI_O	12:28	Fixed Power Factor	7
SI_D	12:29	Curtail	8
SI_K	12:30	Curtail	7
SI_N	12:31	Volt-VAR	13
SI_G	13:45	Volt-VAR	8
SI_B	13:46	Fixed Power Factor	8
SI_O	13:47	Curtail	4
SI_D	13:48	Volt-VAR	3
SI_K	13:49	Fixed Power Factor	9
SI_N	13:50	Fixed Power Factor	18
SI_G	14:21	Volt-VAR	12
SI_B	14:22	Volt-VAR	8
SI_O	14:23	Volt-VAR	6
SI_D	14:24	Volt-VAR	6
SI_K	14:25	Curtail	10
SI_N	14:26	Volt-VAR	13

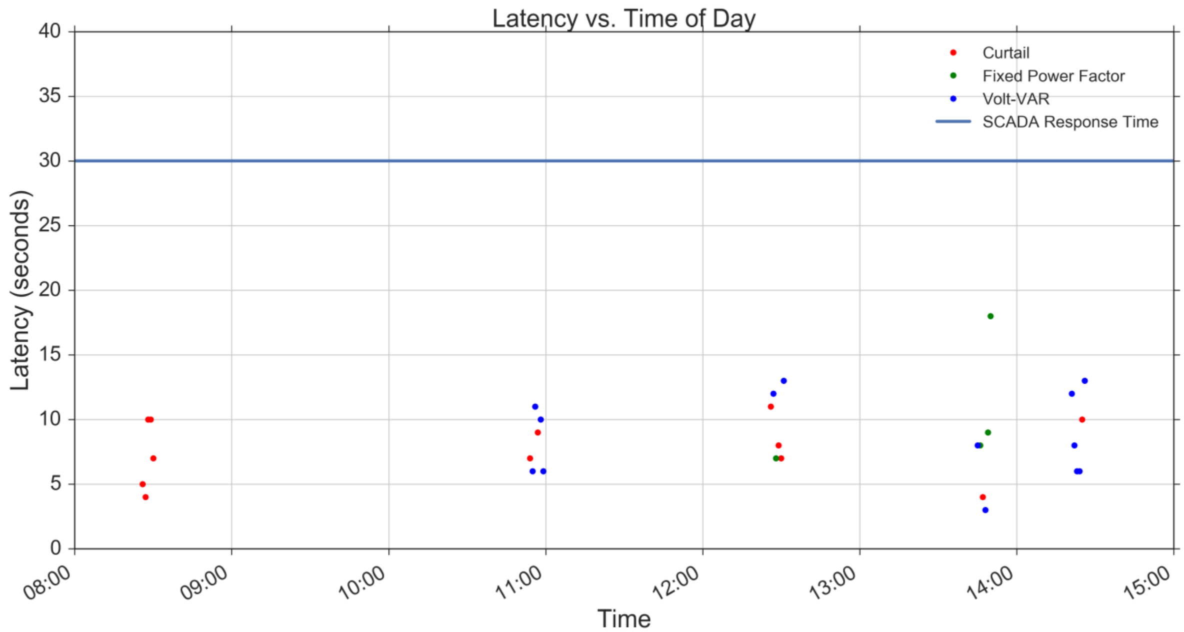

Figure 18. Command Latency vs. Time of Day

5 VALUE PROPOSITION

The purpose of EPIC funding is to support investments in technology demonstration and deployment projects that benefit the electricity customers of PG&E, San Diego Gas and Electric (SDG&E), and Southern California Edison (SCE). Project 2.03A, *Test Capabilities of Customer-Sited Behind-the-Meter Smart Inverters,* successfully tested and demonstrated the use of customer-sited SI technologies and communication infrastructure to provide local grid support to lessen the impacts related to high penetration of DER.

5.1 Primary Principles

The primary principles of EPIC are to invest in technologies and approaches that provide benefits to electric ratepayers by promoting greater reliability, lower costs, and increased safety. This EPIC project contributes to these primary principles in the following ways:

- **Greater reliability:** EPIC 2.03A explores SI capabilities to improve grid reliability by mitigating the impact of renewable resources on secondary (Location 1) and primary (Location 2) system voltage. As of this writing, PG&E has interconnected a total of 355,176 retail BTM PV sites, and is adding an average of 5,000 additional sites every month. In its current form, today's grid—especially its distribution system—was neither designed nor equipped to accommodate such a high penetration of DER while sustaining high levels of electric quality and reliability. By 2020, PG&E expects that 50% of all installed inverters will be smart, and that it will have 1 million total SIs on its system by 2025. This growing penetration of SI-enabled DER presents an opportunity to use advanced SI functions to proactively address these DER-caused reliability issues.

- **Lower costs:** Conventional mitigation measures (transformer upgrades, reconductoring, additional voltage regulation equipment, etc.) provide a possible path towards accommodating more distribution-connected DER in PG&E's service territory. CPUC Electric Rule 21 mandating the use of SIs with autonomous functions provides new, alternative solutions that may perform equally well with potential for improved ratepayer benefits. Specific 2.03A activities targeting cost reductions include 1) the Location 2 field demonstration, which is evaluating SI ability to help mitigate voltage problems resulting from high PV penetration on a distribution feeder and 2) the modeling study, which is performing a holistic cost-benefit analysis of SI capability vs. traditional grid upgrades across multiple PG&E distribution feeders and evaluating the potential to update PG&E standards for performing voltage rise studies when new BTM DERs are interconnected.
- **Increased safety and/or enhanced environmental sustainability**: SIs can help to better integrate renewables, and, therefore, advance California energy policy to increase the amounts of renewable and distributed generation on the grid. By assessing SIs' ability to address DER-caused voltage issues through both the Location 2 field demonstration and modeling, this technology demonstration will shed light on SIs' potential to increase hosting capacity, potentially allowing for faster and more affordable interconnection of additional DERs onto PG&E's distribution system. Additionally, ongoing lab testing activities will evaluate SI responses to extreme grid conditions, which may result in updates to SI standards.

5.2 Secondary Principles

EPIC also has a set of complementary secondary principles. This EPIC project contributes to the following three secondary principles: greenhouse gas (GHG) emissions reduction and efficient use of ratepayer funds.

- **Greenhouse gas (GHG) emissions reduction:** SI technologies can help integrate more renewable resources while enhancing the reliable operation of the grid, resulting in fewer fossil-fuel plants required to remain online. By reducing fossil-fuel generation, there will be a reduction in emissions from the residual fossil-fuel fleet, including GHG emissions.
- **Efficient use of ratepayer funds:** The State of California enacted legislation targeting RPS of 33% by 2020 and 50% by 2030. Solar PV is one of the many resources that can be used to achieve this aggressive standard, but it is important to mitigate the potential negative impacts of high PV penetration.

6 ACCOMPLISHMENTS AND RECOMMENDATIONS

The Location 1 part of the project accomplished its objective of demonstrating the use of residential customer-sited SI technologies and communication infrastructure to provide local grid support to lessen impacts related to high DER penetration. The project also experienced challenges, which, combined with the test results, provided learnings that helped PG&E craft recommendations for future opportunities to explore and leverage SI technologies.

6.1 Key Accomplishments

The project's key accomplishments are summarized below:

- Deployed and tested 15 PV systems, totaling 65.2 kW (DC) of residential SI-enabled PV installed capacity
- Executed 6 field tests, testing SIs' active/reactive power control (Key Objectives A and C):
  1. Fixed Reactive Power of 2 kVAR
  2. Fixed Reactive Power of 4 kVAR
  3. Volt-VAR (autonomous reactive power control)
  4. Fixed Active Power of 1 kW
  5. Fixed Active Power of 2 kW
  6. Volt-Watt (autonomous active power control)
- Demonstrated the ability of a SI system to influence local secondary voltages (Key Objective A).
- Qualified/quantified SI system remote command execution (Key Objectives C and D).
- Characterized communication reliability and latency, and system uptime (Key Objectives C and D).

6.2 Key Learnings

6.2.1 Customer Acquisition

Learning – Identify and account for customer acquisition risks
Vendors struggled to acquire customers due to a combination of issues, each contributing their own unique challenges, such as limited access to customer information and customer fatigue from door-to-door solar. Along with EPIC Project 2.19c, this part of the project learned that customer acquisition risks should be more heavily weighted to establish more realistic timelines and project outcomes for BTM projects, particularly when targeted deployment of DERs is required for safe operation of the grid (e.g. as part of a non-wires alternative PV + storage capacity project).

Learning – Ownership rights may prevent retrofits
The Location 1 demonstration explored the possibility of retrofitting existing, conventional inverters with SIs. Often, residential PV systems aren't owned by the customers or DER vendors, but by 3rd parties. Since 3rd party ownership rights typically prevent any possibility to intentionally curtail power, which was part of the active power control use case, most existing inverters on the demonstration's electrical feeders could not be retrofitted with SIs. Because residential systems make up the bulk of the existing PV customer base, DER technology demonstration projects that rely on residential system retrofits to achieve a certain penetration level may be challenged if 3rd party ownership rights prohibit activities required by the project.

6.2.2 Asset Commissioning & Site Acceptance Testing

Learning – More testing is needed by vendors before assets turned over for acceptance testing
In general, after customer acquisition, commissioning of assets in the field was the most challenging part. This suggests that vendor systems needed more testing by vendors before being handed over to PG&E for site acceptance testing.

6.2.3 Technical Results

Learning – Higher SI-enabled PV capacity is required to properly manifest SI reactive and active power control ability to support voltage regulation
Due to relatively low SI-enabled PV capacity relative to feeder net load, active and reactive power settings had no measurable impact on primary (medium) voltage. Regardless of low SI-enabled PV capacity, a

measurable SI impact was observed at the secondary (low voltage) level. Both SI and power quality meter (PQM) measurements showed that SI active or reactive power support can help regulate voltage at the PCC and across the secondary (low voltage) system. The extent of the secondary voltage regulation depends on the amount of SI active or reactive power and secondary system electrical properties and load conditions. The field demonstration test results in this part of the project show that 1 kW of active power has 2 times more impact on voltage at the PCC than 1 kVAR of reactive power.

Measured impact of SI reactive/active power output on secondary voltage is specific to the local secondary system properties on the field demonstration feeders. Results may vary at secondary systems with different electrical properties and load conditions. Although some voltage support was observed, the low capacity of SI assets included in the field demonstration prevented a more accurate assessment of SI impact on secondary system voltage. Greater SI capacity would be needed to more precisely assess the SI impact. Testing at Location 2 will demonstrate SI voltage support capability in a system with a greater SI capacity relative to secondary system net load.

Learning – SI reactive power can help with voltage regulation in low voltage systems
SI measurements show that SI reactive power support can help voltage regulation at the secondary (low voltage) system. The extent to which SI reactive power support can affect the secondary voltage depends on the amount of reactive power and secondary system electric properties. The field demonstration test results show that on average, 1 kVAR of reactive power absorption resulted in a 0.25 V change at the SI terminals. Results may vary at secondary systems with different electrical properties and load conditions.

Learning – SI active power can help with voltage regulation in low voltage systems
SI measurements show that SI active power support can help voltage regulation at the secondary (low voltage) system. The extent to which SI active power support can affect the secondary voltage depends on the amount of controllable active power and secondary system electric properties. The field demonstration test results show that on average, 1 kW of active support resulted in a 0.5 V change at the SI terminals. Results may vary at secondary systems with different electrical properties and load conditions.

Learning – Volt-VAR functions performed as programmed, with some exceptions
The SIs provided reactive power support in line with Volt-VAR curve settings, either based on pre-programmed dynamic settings or previously-scheduled fixed reactive power setpoints. However, there were some exceptions when SI reactive power output was outside the threshold limits (+/-250 VARs), consistent with previously observed results in a lab setting. This observation from testing is specific to each SI manufacturer and likely results from short-term changes in active power; Phase 2 of the project is expected to generate additional insight into the technology.

Learning – Volt-Watt functions performed well when no other active power commands were executed
Once scheduled, SIs could follow a Volt-Watt curve when this was the only control command. However, when Volt-Watt was enabled and active power curtailment control was cycled on and off, Volt-Watt stopped executing for a short period of time (30 min). This outcome is SI manufacturer-specific[38]and was only observed in the context of this field demonstration. Regardless, the priority and performance of SI functions like Volt-VAR, Volt-Watt and active power curtailment need to be established and tested by SI manufacturers in adherence with a clearly-defined set of industry standards.

[38] The cause of this behavior in this part of the project is suspected to be a glitch in the SI firmware developed for this demonstration.

Learning – Capability to more efficiently upload Volt-Watt settings remotely may be needed for on-demand or real-time SI use cases

PG&E provided individual SI Volt-Watt curve settings to the vendor the day before the test execution, and the vendor "pushed" those settings to individual SI assets in the field. This process was time-consuming and inefficient. While autonomous SI Volt-Watt/Volt-VAR settings are not likely to be changed frequently once implemented (and would likely be pre-loaded onto SIs by manufacturers prior to SI installation), the ability to remotely change settings in real time may be required for on-demand or active SI use cases. More streamlined remote function-setting may be possible with advances since the time of testing at Location 1 of this project.

6.3 Recommendations

Based on the experience gained through the project demonstration, PG&E continues to support the deployment of BTM DER technologies to provide grid support. The project identified several aspects – such as communication uptime – that should be addressed prior to using BTM SI technology as an on-demand, actively-controlled grid resource. A set of recommendations follows to enable BTM SI to be effectively and reliably used as a grid resource in the future.

To achieve the best outcome in this deployment, we recommend that utilities be specific about their reliability requirements now and in the future, and that vendors ensure the technologies they develop are consistent with those utility needs (e.g., reliable communications). We encourage California regulators to continue to support the ongoing utility and vendor discussions around DER provision of distribution services through the Rule 21 proceeding and Smart Inverter Working Group, Distribution Resources Plan, and IDER.

The SI assets participating in this technology demonstration demonstrated the potential to support voltage regulation in their respective low voltage systems. However, the deployment and performance of the SI assets faced challenges in customer acquisition, commissioning, software and communications that should be addressed before advancing this functionality beyond the technology demonstration stage.

As with any new technology, SI solutions require additional standardization and investment over time to reach maturity. Overall, PG&E believes that the industry is on the right track to make SIs a reliable and scalable grid resource over time.

6.3.1 Customer Acquisition

To improve the customer acquisition process for future DER programs, we offer the following recommendations:

- Vendors should set conservative expectations for acquiring customers and plan for long asset deployment timelines.
- Industry should not rely on targeted DER deployment as a quick or easy solution to provide distribution services at specific locations where they are needed.
- Utilities should find alternatives to new customer acquisition when pursuing demonstrations with the ability to deploy new assets, such as identification of feeders with pre-existing customer-owned and not 3rd party-owned DERs. This was the approach taken with Location 2 of EPIC 2.03A, where existing commercial-scale SIs could be retrofitted for the purposes of the demonstration.

6.3.2 Communications

The following summarizes challenges and proposed recommendations to overcome communication challenges.

- Communication infrastructure performance must improve relative to what has been observed in the project to-date for utilities to leverage DER remotely with real-time control. The project utilized residential internet to communicate with the residential assets at Location 1. The commands were sent to the communication gateway, which were connected to the residential customer's internet router by an Ethernet connection. The communication gateway stored the schedule and sent commands over the air to the inverter at the command execution time. The field demonstration results showed that communication uptime was not consistent and reliable across all SI assets in the field. Also, the vendor-specific aggregation platform provided by the vendor as a part of this technology demonstration did not prove to be a consistently reliable solution. Therefore, it is essential for PG&E to have an integrated and scalable system to communicate distribution dispatch instructions to the SIs directly or via an aggregator, as opposed to using vendor-specific aggregation platforms. PG&E intends to further explore this topic in its proposed EPIC 3.03 demonstration Advanced DERMS and ADMS, which will evaluate different approaches to integrate DER technologies with utility grid management systems.

Communication between the web application and individual SI assets at Location 1 was an ongoing challenge in this technology demonstration. In some cases, dispatch signals were not followed because a communications outage prevented the SI asset from receiving it. Before pursuing wider-scale deployment of this technology to provide remotely requested, on-demand grid services, we recommend the following steps to improve communications reliability:

- Uniform metrics for communication between utilities and BTM SI systems are needed. Utilities should specify maximum latency and minimum communication uptime for BTM SI systems participating in a utility program.
- Vendors should pursue alternative communications methods to residential customers' Wi-Fi + Zigbee in situations where this configuration cannot meet utilities' reliability requirements.
- Vendors and utilities together should explore hard-wired DER communications pathways.
- Additionally, no standards exist to ensure that communication pathways to SIs are implemented securely. Further exploration and testing is required to develop and validate cybersecurity requirements which safeguard against various threat scenarios intended to maliciously operate SIs outside of their expected manner. For example, IEEE 1547 (2018 DER Interconnection Standards) does not address cybersecurity of communication protocols, devices, or the interfaces, and should be updated to address these concerns.

6.3.3 Foundational Utility Capabilities

Current utility operational systems are not yet capable of using this advanced SI technology to its fullest extent. Further utility investment is required to deploy technology to connect to SIs and utilize DERs as a reliable grid resource in the future, especially if SIs are controlled at scale and in real-time across the electrical distribution system. Utilities will need to invest in foundational capabilities and systems to enable 1) real-time communication of distribution dispatch instructions to the aggregators/SIs (active control), and 2) automated optimization of grid operations leveraging both traditional distribution operations equipment and SI-equipped DERs. Given the dynamic operating conditions of each feeder and the localized distribution grid, the frequent rerouting of power over different distribution feeders via switching to minimize impact of local outages, and the need for work clearances to ensure the safety of the public and utility crews, operational capabilities that can automatically optimize solutions for grid conditions and communicate signals to aggregators and or individual DERs would greatly enhance the value of DERs to the grid operator and planner.

In this demonstration, PG&E communicated a pre-established test plan directly to the aggregator's platform. To leverage BTM PV SIs as a more widely deployed resource across the distribution grid on a real-time basis, grid operations and control systems will need to be able to provide instructions to localized DERS and optimize the tools available to grid operators to effectively, efficiently and safely manage real-time operating conditions. These new capabilities are currently being explored as part of PG&E's distribution technology roadmap, which will seek to improve situational awareness and operational efficiency through implementation of an Advanced Distribution Management System (ADMS), additional SCADA enhancement and integration, advanced planning tools, and network upgrades.

Additional advanced DER management capabilities are also being contemplated to optimize and control the use of DERs to meet dynamic distribution grid conditions and constraints. Although SI-equipped DERs may participate in vendor aggregation platforms that can optimize and dispatch DERs within a fleet, the utility integrated grid platform will need to translate grid needs into signals delivered to DERs or to aggregations of DERs. These new capabilities, along with foundational ADMS and network upgrades, will be necessary to fully realize the value of SI-equipped DERs.

6.3.4 Next Steps – Continued SI Demonstration at Location 2 and Other Ongoing Activities

- Building on the Location 1 work, further exploration is currently underway in the ongoing EPIC 2.03A project:
    - **Evaluate the potential for higher penetration of SI-enabled PV assets to provide both secondary and primary voltage support** (Key Objective A) – Relative to available DERs at Location 1, greater SI-enabled PV asset penetration at Location 2 will enable a more robust assessment of SI function effectiveness in addressing grid level voltage issues stemming from high BTM PV penetration. By retrofitting a higher percentage of existing PV installations with SIs (35% of PV name plate rating/peak feeder demand), Location 2 testing will explore SI operation impact on primary feeder voltage. This feeder is also more prone to voltage disturbances than the Location 1 feeders and has previously experienced high voltage conditions, possibly tied to its overall high PV penetration (predominantly customer-owned commercial installations where SI retrofits required for the project were possible). Using this feeder to quantify voltage response to changes in SI active and reactive power operation will increase understanding of SI functionality.

    - **Evaluate a vendor-agnostic aggregation platform** (Key Objectives C and D) – Location 2 of this project will also evaluate remote monitoring of aggregations of solar assets, as well as the remote implementation of changes to SI settings. While Location 1 used a vendor-specific aggregation platform, Location 2's configuration will use a vendor-agnostic utility aggregation platform and existing satellite communications infrastructure to relay information from each solar PV site to a cloud-based server, where it will then be processed and sent to PG&E.

Ideally, such a system can communicate to a number of different SI vendors and installers found within a utility's territory. Testing will seek to:

- Inform PG&E's perspective on the complexity of coordination of large numbers of SIs on its system
- Inform telemetry communication requirements for SI assets in various modes of functionality
- Assess latency and reliability of the DER communications infrastructure, as well as ease of integration of the aggregation platform with PG&E's IT systems
- Inform future advanced technology SCADA, ADMS (Advanced Distribution Management System) and DERMS requirements

- **Evaluate customer energy generation curtailment as a function of SI settings** (Key Objective B) – Customer energy curtailment due to Volt-VAR and Volt-Watt functions will be measured in the Location 2 field demonstration by maintaining one baseline SI at each test site. The baseline SI will not run any Volt-VAR or Volt-Watt curves, and energy production at this SI will serve as a baseline for comparison against other SIs at the site actively running curves[39]. Additionally, a curtailment predictor tool will be built to estimate customer curtailment from the Volt-Watt function. This tool will estimate potential reduction in customer generation using the customer's voltage profile pre- and post-interconnection.

- **Conduct a series of SI test cases in the laboratory** (Key Objective E) – The objective of these tests is to gain an understanding of how SIs perform in both normal and extreme grid conditions. Key learnings PG&E hopes to gain from lab testing:
    - SI ability to follow Volt-VAR and Volt-Watt curves and performance in areas where these curves overlap
    - Impact of harmonics on residential SIs
    - Impact of harmonics on electric vehicle (EV) Level 2 and DC super chargers (DCFCs)
    - Impact of out of phase reclosing on three-phase SIs
    - Efficacy of Frequency Watt in maintaining stable grid frequency in high PV penetration scenarios, as simulated using a grid simulator

- **Explore potential cost savings and benefits of SIs across the PG&E system** (Key Objective F) – Through a modeling study, ongoing EPIC 2.03A activities will technically determine the necessary conditions and requirements for SIs to provide benefits to utility customers. Potential benefits include supporting voltage to avoid distribution upgrade costs, and guiding PG&E on how best to engage with SI-enabled DERs in the future. This analysis will be specific to PG&E's system and will evaluate SI functions on several representative distribution feeders. Insights from this modeling demonstration will drive greater understanding of:
    - Costs/benefits of SI deployment based on grid characteristics
    - Engineering standards regarding voltage rise calculations for BTM DERs
    - Penetration and siting considerations for DER impacts

[39] The 14 PV sites evaluated at Location 2 of the demonstration each have multiple SIs per site, from 4 at the smallest site (132 kW) to 41 at the largest site (984 kW).

- Impacts of SI-enabled PV systems when coupled with passive/autonomous battery storage
- Evaluation of the cost-effectiveness of SIWG Phase 1 and Phase 3 functions, to determine incremental benefits of autonomous SI functions

7 DATA ACCESS

Upon request, PG&E will provide access to data collected that is consistent with the CPUC's data access requirements for EPIC data and results.

8 CONCLUSIONS

EPIC 2.03A Location 1 findings demonstrated basic technical functionality of SI autonomous functions designed to mitigate local voltage issues associated with high DER penetration, and characterized remaining hurdles to scaled SI deployment for grid support. While this initial work in the project did not present findings on SI ability to affect primary voltage (a focus of the remaining time in the project), it did demonstrate the potential for local voltage support from SIs to help mitigate local secondary voltage challenges caused by high PV penetration. SI ability to impact secondary voltage demonstrates that, with necessary improvements to the technology and processes related to its deployment, SI technology represents a promising avenue to address California’s goals for DER integration.

At the same time, project activities completed to date provided insights into communication performance, highlighting uptime as a concern for implementation at scale. While latency observed in this demonstration may qualify BTM SI technology in autonomous (set & forget) applications, communications uptime must be improved relative to this project’s observations to remotely (on-demand) leverage SI control capabilities in system operations. To enable these active control use cases, investment in utility foundational systems and advanced DER management capabilities will be needed. This project also illustrated challenges around targeted deployment of SI-equipped PV (obtaining the desired quantity of resources, when and where they were needed) and around having sufficient penetration to rely on SI-equipped PV for distribution system needs.

These findings on the potential use of SI autonomous capabilities to support local voltage are expected to be valuable for distribution grid operations, distribution planning, and customer programs. Feedback from this technology demonstration can inform process changes and utility requirements needed to successfully integrate renewable resources controlled by SIs. Specifically, ongoing EPIC 2.03A testing may provide additional evidence of SI ability to support secondary voltage that allows PG&E to update its secondary voltage rise standards for new PV interconnection. Learnings can also inform the Distribution Resources Plan (DRP) and Integrated Distributed Energy Resource (IDER) proceedings, including Distribution Infrastructure Deferral Framework, Competitive Solicitation Framework, ongoing Rule 21 Order Instituting Rulemaking (OIR), and Grid Modernization Planning filings.

Location 1 of EPIC Project 2.03A evaluated residential SI technology, monitored and managed through a vendor-specific aggregation platform, as a foundational technology. However, many questions remain. BTM SI technologies need to be further demonstrated, especially SI impact on both primary and secondary voltage support at higher PV penetration levels. With the Location 2 component of the project, a commercially-focused SI field trial, PG&E plans to assess the ability to control commercial SIs via a vendor-agnostic utility aggregation platform and provide insight into SI ability to provide voltage support on the primary side of the transformer. Ongoing activities will also include lab testing to evaluate SI response to a variety of grid conditions as well as a modeling demonstration to perform a cost-benefit analysis of SI functions on PG&E's distribution system relative to traditional distribution grid upgrades. Ongoing project activities will also measure generation curtailment resulting from Volt-Watt activation both by using baseline inverters at the Location 2 field test sites, via lab testing activities and through the grid modeling demonstration.

Once completed, EPIC Project 2.03A will enhance understanding of the potential of SI for electric utilities, regulators, adjacent industries, policy makers, and prospective vendors, toward building a broader solution to the ultimate benefit of utility customers. PG&E plans to continue to champion this effort through continued support and presentations at industry meetings and to seek opportunities to continue to assess use of this technology.