Pacific Gas and Electric Company

EPIC Final Report

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Table of Acronyms

AB	Assembly Bill
AC	Alternating Current
ADMS	Advanced Distribution Management System
AHJ	Authority Having Jurisdiction
BTM	Behind-the-Meter
CAISO	California Independent System Operator
CEC	California Energy Commission
CES	Customer Energy Solutions
CPUC	California Public Utilities Commission
DC	Direct Current
DER	Distributed Energy Resources
DERMS	Distributed Energy Resource Management System
DIDF	Distribution Investment Deferral Framework
DRP	Distribution Resources Plan
EDRS	Electronic Document Routing System
EPIC	Electric Program Investment Charge
ESS	Energy Storage System
GHG	Greenhouse Gas
IDER	Integrated Distributed Energy Resources
IOU	Investor-Owned Utility
kw	kilowatt
kVA	kilovolt-ampere
kVAR	kilovolt-ampere-reactive
kWh	kilowatt-hour
LOB	Line of Business
M&V	Measurement and Verification
MW	megawatt
NWA	Non-Wires Alternative
PG&E	Pacific Gas and Electric Company
POU	Publicly Owned Electric Utility
PTO	Permission to Operate
Pub. Util. Code	Public Utilities Code
PV	Photovoltaic
R.	Rulemaking
RA	Resource Adequacy
R&D	Research and Development
RFO	Request for Offers
R.	Rulemaking
SCADA	Supervisory Control and Data Acquisition

SCE	Southern California Edison Company
SDG&E	San Diego Gas & Electric Company
SoC	State of Charge
SOW	Statement of Work
TD&D	Technology Demonstration and Deployment
V	Volt
VAR	volt-ampere reactive

1 Executive Summary

This report documents EPIC *Project* 2.19C – *Customer-Sited and Community Behind-the-Meter Storage,*[1] project achievements, highlights key learnings from the project that have industry-wide value, and identifies future opportunities for Pacific Gas and Electric Company (PG&E) to leverage this project. PG&E's Electric Program Investment Charge (EPIC) Project 2.19C – *Customer-Sited and Community Behind-the-Meter Storage* tested the use of customer-sited energy storage technologies to reduce peak loading and absorb distributed energy resources (DER) generation.

In California, increasing adoption of DERs is resulting in a significant change in the power flows on the distribution grid, levels and timing of localized congestion and voltage, as well as in the net load profile. These changes can create challenges to system planning and operations on both distribution and transmission electric system. Energy storage has the potential to help address these issues by managing localized load levels as well as by providing grid services. This project sought to understand customer interest in and adoption of BTM storage technologies, as well as the technical feasibility for leveraging these assets as a resource for grid services. The lessons learned through this demonstration support the technical potential of BTM storage technology to provide grid services and underscore the investments needed in order to leverage the technical capabilities demonstrated by this project on a larger scale.

The project demonstrated both the technical potential of BTM energy storage to provide grid reliability support, and highlighted next steps required to enable scalability, to facilitate widespread use of BTM energy storage for grid support, and to achieve, ultimately, the full realization of their value of as a grid resource. While there were challenges in customer acquisition, asset deployment, asset communications, flexibility forecasting, and dispatch algorithm development, the demonstration and field test results showed that aggregated BTM storage resources have the potential to be utilized by the utility to reduce electric load or to absorb distributed generation on a utility distribution feeder.

With additional investments that enable grid planning and operations to achieve better utility monitoring, visibility, and control capabilities, BTM energy storage technology has the potential to become a net load management tool that can play a significant role in shaping California's energy future. For BTM energy storage assets to be reliably used for distribution or grid services, the utility will need to have additional hardware and software systems (e.g., two-way communication systems, operational protocols and priorities, a Distribution Energy Management Systems (DERMS) platform, sensors and controls, etc.) to provide accurate visibility into asset performance and availability, and assurances that the BTM energy storage assets will consistently and reliably respond to dispatch signals. This demonstration project identified several key areas where a more scalable solution is needed to support the use of BTM storage as a grid resource in order to overcome implementation and communication challenges.

Because of this project, distribution planning engineers, program managers and operators can better understand the current status of BTM energy storage technology capabilities, reliability, and maturity, and the need for further enhancements to support commercial scale deployment. This suggests that

[1] Also referred to as 2.19 Enable Distributed Demand-Side Strategies & Technologies.

with these enhanced capabilities BTM energy storage can be considered as a potential resource to address grid capacity constraints and support integration of cost-effective distributed resources and generation, including renewable resources.

In addition, this project provided insights into communication performance: discovering communication uptime as a concern for implementation at scale. When assets were online, they met most use case requirements, with latency that is within Supervisory Control and Data Acquisition (SCADA) timeout limits, but not within frequency regulation requirements. With the appropriate communication infrastructure, a Distributed Energy Resource Management System (DERMS) operational platform (with optimization and signaling capabilities) that can integrate BTM energy storage, smart inverters and traditional grid operating tools and equipment, and clear operational protocols, implementation and scalability challenges can be overcome to enable BTM storage to provide grid services. Such investments in scalability can enable BTM storage resources to ensure asset availability, and provide timely, accurate and consistent responsiveness. With improvements in the flexibility forecast, data accuracy, and communications uptime, BTM energy storage resources would be able to meet grid reliability standards and protocols, and provide reliable and timely responsiveness. This would enable utilities to leverage BTM energy storage in system planning and operations and realize their full value and capabilities to benefit customers and reduce Greenhouse Gas (GHG) emissions.

EPIC Project 2.19c created a BTM energy storage technology demonstration as a foundation upon which electric utilities, regulators, adjacent industries, the California Independent System Operator, policy makers, and prospective hardware and software vendors can begin scaling up and building a broader solution for 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.

In terms of next steps, BTM energy storage technologies need to be further demonstrated in the field and scaled up in other field projects. Feedback from PG&E test engineers will inform process changes and utility requirements needed to successfully integrate and determine the commercial scalability of BTM energy storage technologies. Also, this project's learnings about BTM technology capabilities to provide grid services on utility request will inform the next steps in Distribution Resources Plan (DRP) and Integrated Distributed Energy Resources (IDER) proceedings and workshops, including Distribution Infrastructure Deferral Framework, Competitive Solicitation Framework, Grid Modernization, and Rule 21 Interconnection workshops and filings.

The project established a set of objectives, which are outlined below.

Key Objectives

The project objective was to demonstrate distributed demand-side technologies and approaches to address local and flexible resource needs.[2] Specifically, the project aimed to:

A. Evaluate the technical ability of BTM energy storage to **reduce peak loading** or absorb distributed generation on utility distribution feeder(s), with sufficient reliability for distribution grid operations

[2] Local and flexible resource needs is used generally here, and does not apply to the specific requirements to qualify for local and flexible resource adequacy (RA).

B. Clarify storage **technology and process requirements** to integrate and interoperate DERs to address grid needs, and characterize barriers to deployment at scale relative to today.
C. **Demonstrate and evaluate communications** available to provide DER visibility, monitoring, and control in order to address grid needs reliably today.
D. Evaluate the ability of BTM energy storage to **simultaneously provide services** to a utility and the on-site customer, correctly prioritizing distribution services.

The project partnered with one residential and one commercial Energy Storage System (ESS) vendor to deploy customer-sited BTM energy storage resources, which were individually and in aggregate controlled and monitored by the project team. This project was co-located with EPIC 2.03a – Test Smart Inverter Enhanced Capabilities - Photovoltaics (PV) and EPIC 2.02 – Distributed Energy Resource Management Systems (DERMS) on a distribution feeder located in San Jose, CA. All three projects shared these field resources.

Key Takeaways and Recommendations
The following findings are the key takeaways and lessons learned from this project:

- **BTM storage technology possesses the technical capabilities to reduce peak load and absorb generation**, in response to grid instructions. However, **further action and investment is required to demonstrate capability for scaled deployment** of the technology as an effective and reliable grid resource in the future (Key Objective A).
- Lessons learned inform steps that need to be taken to successfully scale the project and to **operationalize and integrate BTM energy storage** to reliably meet the needs of the grid. **To achieve the key objectives in a wider scale production environment, additional software and hardware investments are necessary relative to what was included in the technical demonstration** (Key Objectives A, B, C, D). Specific enhancements that would enable grid planners and operators to fully realize the value of BTM energy storage to meet grid reliability needs include: **Increasing the direct and granular visibility into the operational status of distributed energy resources (e.g., state of charge, etc.) to facilitate successful distribution operations in a high DER penetration future.** This demonstration highlighted several DER operational metrics that must be monitored reliably for DER distribution services to be scaled: e.g., state of charge, asset availability, metrology accuracy, and timeliness, consistency and accuracy of real-time response. Enhancements in the accuracy of real-time communications, increased uptime of operating assets, and greater clarity and adoption of a standard definition of asset availability would enable the full realization of the expected DER value. By providing grid operators with visibility into the operational data from the aggregator or the facilities, and ensuring the dependability/reliability of the resource for planners, BTM energy storage can become an effective grid resource.
- **An integrated grid platform, which does not exist today, would be needed to enable 1) real-time communication of distribution dispatch instructions to the aggregators/storage units, and 2) automated optimization of grid operations leveraging both traditional distribution operations equipment and BTM energy storage. (Key Objectives B and C)** Given the dynamic operating conditions of each feeder and the localized distribution grid, the frequent rerouting of power over different distribution feeders to minimize the duration and magnitude of local

outages, and the need for work clearances to ensure the safety of the public and utility crews, operational capabilities that can automatically analyze grid conditions, determine optimized solutions, and communicate signals to aggregators/assets would greatly enhance the value of DERs to the grid operator and planner. In this demonstration, the project team communicated a pre-established test plan directly to the aggregators platforms. To leverage distributed storage as a more widely deployed resource across the distribution grid on a real-time basis, grid operations and control systems will need to have the capabilities of an integrated grid platform that would provide instructions to localized DERS and optimize the tools available to grid operators to effectively, efficiently and safely manage real-time operating conditions Additional equipment and protocols beyond those employed in this technical demonstration will be necessary to mitigate inaccurate or inconsistent reporting to avoid under-delivery of battery discharging, or inconsistent assessments of the BTM energy storage resources' state of charge and energy availability, which can diminish the value of the BTM energy storage resource to the grid.

- **Implementation of Behind the Meter storage systems to support grid reliability is not yet at a "plug-and-play" state. (Key Objectives A, B).** The project experienced challenges related to customer acquisition, permitting and interconnection complexities. (**Section 3.4, Section 3.7)** Challenges in achieving customer acquisition targets for each vendor may have been due to a variety of circumstances, such as customers with existing solar system having restriction on testing rights, the customer engagement strategy, and customer fatigue from door-to-door solar sales. One project learning is that customer acquisition risks should be identified and accounted for upfront to establish more realistic deployment timelines, particularly when targeted deployment of DERs is required for safe operation of the grid (e.g. as part of a non-wires alternative capacity project). Furthermore, the process for interconnecting solar with storage is also more complex and more variable than the process for solar-only installations from a permitting and engineering requirements standpoint. There are additional engineering and tariff complexities for interconnecting solar and storage which are not present in solar interconnections. At the time of the project's asset deployment, PG&E and one of the vendors had already each processed hundreds of thousands of solar interconnections, and a few hundred solar with storage. Nevertheless, neither the vendor nor PG&E anticipated the length of time required for the project's solar plus storage interconnections which ranged from 8 to 27 weeks. The process for permitting the storage systems with local authorities likewise created additional complexities and delays. Anticipating these challenges and timeline impacts to bring assets online in the future is paramount.
- **Targeting the right customers for acquisition in right areas (Key Objectives A, B)**–Addressing local reliability needs on the distribution grid using BTM energy storage or other DERs in an identified area should be based on an assessment of the sufficiency of customers that could participate which can provide the necessary capabilities.
- **There still exists an open question as to how widespread customers' demand/receptivity is to this technology (Key Objectives A, B)**, their willingness and extent to which they will participate in programs that can produce realizable grid reliability benefits. The residential

vendor gave away a "free" battery and the commercial vendor had financial incentives in place but that was not sufficient to draw significant interest from the original targeted number of customers. A question arises of whether the host utility taking an active role in customer acquisition versus a "vendor-led" approach, as was taken in this technical demonstration, could have affected customer acquisition for the project. For future technology demonstrations that may involve customer sited asset deployment, it would be beneficial to evaluate whether the customer acquisition process would be more successful if the utility takes the lead or a stronger role on customer acquisition rather than the vendor.

- **Addressing distribution constraints requires sufficient scale and response time on the feeder to mitigate potential issues (Key Objectives A and B)**. Targeted customer acquisition in a short timeframe was challenging, resulting in a 66% shortfall of resources relative to the project's objective. In the context of addressing an actual distribution constraint (which did not exist on this feeder), such a significant shortfall relative to expectations could result in failure to resolve the constraint. **(Section 3.7)** This issue needs to be better understood to pursue scalability.
- **Reliable communication links and response time protocols are critical for success. (Key Objectives A, B, C and D)**. The project utilized hard-wired residential internet to communicate with the residential assets and cell connections for the commercial assets. Residential internet is a generally low-cost solution but has significant drawbacks and may not be suitable for utility-scale programs. **(Section 4.2)**
    - **Reliable communications with DER assets** – The combination of communication protocols (e.g., Zigbee and customer internet) caused problems. Residential internet is low cost, but would not meet utility-scale robustness and reliability. For assets to participate in grid services at scale, more reliable and standardized communication performance should be adopted.
    - **Frequency regulation requires faster response time** – For both vendors, the response times were under 30 seconds, which was satisfactory for the purposes of this project. However, faster response times may be needed for certain California Independent System Operator CAISO ancillary services. While CAISO ancillary services were not in scope of this project, more robust communication would be required to enable this technology.
- **Importance of prioritization of distribution grid reliability services for Multiple Use Application DERs. (Key Objectives B and D)**. The demonstration identified instances where distribution dispatch signals were not prioritized relative to other uses. For BTM resources to fully provide grid reliability value through distribution dispatch, clear and consistent prioritization would be required. **(Section 4.3)** Grid needs can range from regularly shifting load to help manage the duck curve at the CAISO system level to dispatching in response to a utility distribution operator command to mitigate local voltage or capacity issues. Ability of BTM storage to serve both customer and grid needs is a key advantage; however, this project sheds light on the complexity of achieving the reliable dispatch of such systems. Some challenges are commercial in nature, such as the inability to dispatch the large percentage of

BTM resources that are subject to lease agreements which prohibit curtailment, resources that are being used to minimize customer bills (e.g. demand charge management) or resources that are sold as "backup power supplies." Other challenges are technical, such as the challenge of consistently maintaining communication with resources without an expensive dedicated pathway. In many cases, challenges arise from the lack of mature systems and vendors. These range from a large number of control algorithm glitches uncovered during functional testing to basic misunderstandings about how to measure key operating metrics like state of charge and available capacity.

Technical Observations and Results

Some key technical findings are listed *Table 1.* These are discussed in more detail in Section 3.8 Key Learnings, Takeaways and Recommendations.

Table 1: Project Technical Observations and Results

	Technical Observations	Results
1	The commercial vendor's algorithm was effective at shaving demand charges.	This was successfully executed repeatedly.
2	Pairing solar and storage is an effective way to "smooth" expected generation output.	The residential energy storage system was effectively used to locally compensate for loss of solar generation, even during such severe intermittency levels as seen on the August 21, 2017 solar eclipse.
3	Responsiveness to distribution dispatch instructions complicated or preempted by prioritization of demand-charge shaving.	Responsiveness to distribution grid dispatch instructions to support grid reliability can be compromised at times when the instructions result in conflicts with other priorities for the BTM energy storage. In order for storage assets to be a dependable and reliable tool used for distribution operations, the distribution system operations need to maintain priority relative to other objectives.
4	Inaccurately reporting of the availability of the BTM energy storage to the DERMS platform, resulted in the inability to perform scheduled bids. This reveals a need to understand implications of multiple systems communicating instructions to one resource, and the prioritization schema used to resolve conflicting instructions.	In order for storage assets to be reliably used for distribution operations, accurate and timely information regarding the availability/state of charge of the BTM storage resource is paramount.
5	A DERMS-type platform is necessary to enable utilization of BTM storage as a resource to manage the grid.	This technical demonstration was held in conjunction with EPIC 2.02 project, that tested a DERMS system. Absent an integrated grid platform like DERMS, the realizable value and effectiveness of a BTM energy storage system as a grid reliability resource would be limited to manual dispatch operations.
6	The project team was required to leave 50% State of Charge (SoC) in residential customer batteries overnight, despite evening discharge and morning charge schedule requirements, to meet customer desire for outage protection. This was neither the most energy or Greenhouse Gas (GHG) efficient path.	Customer desire to have outage protection reserves overnight may conflict with grid needs. Determining prioritization of customer desires and grid needs will be necessary as BTM resources become more pervasive.
7	Not all distribution operations dispatch instructions were accepted and/or met due to miscalculation of reserve requirements and internal losses.	Greater refinement of system control algorithms by both aggregators and the utility will be necessary to avoid acceptance of dispatch instructions that cannot be followed. Continued field testing of BTM assets is needed in order to identify and rectify issues before storage is used for grid reliability.
8	SoC and available capacity need to be defined across storage vendors. The two vendors calculated these metrics differently: one based on usable capacity and one based on total capacity.[3]	Utilities need to set definitions early in the procurement process and ensure vendors are able to meet these capacity values.

[3] Lithium-Ion batteries do not operate from 0-100% of total energy capacity, otherwise they have increased degradation.

Implementation Challenges and Resolutions

Some of the key implementation challenges encountered by the project and their respective resolutions are listed ***Table 2***. These are discussed in more detail in Section 3.7. – Challenges.

Table 2. Implementation Challenges and Resolutions

	Implementation Challenges	Resolution
1	Customer acquisition took longer and resulted in fewer installations than expected.	Testing approach changed from "test all at the same time" to "test as becomes available." This resulted in fewer test result data points than anticipated, and prevented further delay of the project completion. The project team originally pursued existing solar customers. However, this is not possible for many residential systems because they are financed and owned by third-party institutions. This may be a significant challenge for deploying technologies to existing residential systems; as these parties may have little to no interest in grid services.
2	Construction of some sites experienced long delays, impacted by various factors including construction company schedules, site specific scheduling requirements, and location of the ESS.	Construction lead times were longer than originally planned for.
3	Vendor software and hardware malfunctions delayed site acceptance testing and project demonstration activities.	More time than originally planned for was required for vendors and/or their technology providers to troubleshoot problems
4	The permitting and interconnection complexities resulted in longer implementation timeframes for bringing assets online. Due to the relative complexity of storage as a technology, –the agencies including PG&E and Authority Having Jurisdiction (AHJ)[4] - wanted to ensure the safety of the technology and compliance with applicable rules. However, this caused schedule variability for permitting and interconnection processes which led to delayed operations for both vendors.	The interconnection and permitting processes for storage are more complex than that of solar, taking months rather than days. This was longer than originally planned for. The project team took steps to tightly manage the interconnection requests for the project's solar plus storage assets. Regardless, these steps resulted in only slight improvement in process timelines, mainly because solar plus energy storage processes require more thorough structural and electrical engineering analyses due to the ability of storage to act as both load and generation. The technical complexities, along with additional rules, led to a miscellaneous set of project issues with inconsistent schedule durations which were difficult to anticipate. Consistency across AHJs on permitting requirements in the future would also reduce DER deployment timelines.

[4] 5AHJ may be a federal, state, local, or other regional department or individual, or others having statutory authority.

Project Milestones

- Deployed 240 kW, 2 hours of customer-sited BTM commercial storage and 64.8 kW, 2 hours of residential storage.
- Commissioned 20 residential and 2 commercial sites with BTM energy storage systems.
- Executed 13 field tests, testing BTM energy storage systems control, communications, and measurement accuracy performances.
- Demonstrated the effectiveness and key challenges encountered of DERs providing distribution services.
- Assessed the qualitative and quantitative performance of the BTM energy system in order to validate the DER provided the service when needed including command execution, meter accuracy, communication reliability and latency, and system uptime.
- Demonstrated the ability and challenges encountered of BTM energy storage solutions to provide service to both the utility and the customer, if designed to do so.
- Assessed the ability of vendors to accurately prioritize distribution and customer requests.

Conclusion

The project demonstrated both the possibility that BTM energy storage can support grid reliability, as well as the additional work needed to enable scalability, widespread use of BTM energy storage for grid support, and full realization of its value as a grid resource. While there were challenges in customer acquisition, asset deployment, asset communications, flexibility forecasting, and dispatch algorithm development, the demonstration and test field results showed that aggregated BTM storage resources have the potential to be utilized by the utility to reduce electric load or to absorb distributed generation on a utility distribution feeder. With additional investments that enable grid operations that support better utility monitoring, visibility, and control capabilities, BTM energy storage technology has the potential to become a net load management tool that can play a significant role in shaping California's energy future. For BTM energy storage assets to be reliably used for distribution or grid services, the utility will need to have additional hardware and software systems (e.g., two-way, communication systems, DERMS, prioritization protocols, etc.) to provide visibility into accurate asset performance and availability, and assurances that the BTM energy storage assets will consistently and reliably respond to dispatch signals in a timely manner. This demonstration project identified several key areas where a more scalable solution could support the use of BTM storage as a grid resource if some of the implementation and communication challenges are overcome.

Because of this project, distribution planning engineers and program managers can better understand BTM energy storage technology capabilities, reliability, and maturity. This suggests that BTM energy storage can be considered as a potential resource to address grid capacity constraints and support integration of cost-effective distributed resources and generation, including renewable resources.

In addition, this project provided insights into communication performance: discovering communication uptime as a concern for implementation at scale. When assets were online, they met most use case requirements, with latency that is within Supervisory Control and Data Acquisition (SCADA) timeout limits, but not frequency regulation requirements. If uptime communications requirements are met, implementation challenges are overcome, and asset availability is accurately reported, BTM energy storage technology may be able to provide grid services. To leverage BTM energy storage in system operations, flexibility forecast accuracy and communications uptime must be improved. Further, absent an integrated platform, implementation at scale is limited.

The project identified several key barriers that should be addressed prior to expanding the use of BTM storage as a grid resource including gaps in asset data accuracy and visibility, and scalability of the utility-aggregator communications system. A set of recommendations follows to enable BTM storage to be effectively and reliably used as a grid resource in the future.

The project served as an informative and enabling precursor to the fulfillment of California State Assembly Bill (AB) 2514[5] and AB 2868,[6] which require local, investor-owned electric utilities (IOU) to procure energy storage systems. In addition, this project aimed to support the California Public Utilities Commission (CPUC) proceeding, Distribution Resources Plan (DRP) R.14-08-013,[7] evaluating aggregated behind-the-meter (BTM) customer energy storage as a non-wire alternative (NWA) to address capacity constraints identified using the Distribution Investment Deferral Framework (DIDF) in the utilities distribution planning process. For that reason, PG&E is investigating customer-sited BTM energy storage technology readiness and improvement opportunities. This project provided valuable learnings related to use of customer-sited BTM energy storage technology in support of advancing the integration of DERs into PG&E's distribution planning, grid operations and investment processes.

EPIC Project 2.19c created a BTM energy storage technology demonstration as a foundation upon which electric utilities, regulators, adjacent industries, policy makers, and prospective vendors can build 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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[5] AB 2514 was designed to encourage California to procure by 2020 and incorporate by 2024 energy storage into the electricity grid in order to support the integration of greater amounts of renewable energy into the electric grid, defer the need for new fossil-fueled power plants and transmission and distribution infrastructure, and reduce dependence on fossil fuel generation to meet peak loads.
http://www.energy.ca.gov/assessments/ab2514_energy_storage.html.

[6] The California Public Utilities Commission (CPUC) has issued an order requiring that PG&E, SCE, and SDG&E propose programs and investments for up to 500 megawatts (MW) of distributed energy storage systems, distributed equally among the three utilities, above and beyond the 1,325 MW target for energy storage already required pursuant to AB 2514.
http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M184/K630/184630306.PDF.

[7] Distribution Resources Plan ((Rulemaking (R.) 14-08-013).

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2 Introduction

This report documents EPIC *Project 2.19c Customer-Sited and Community Behind-the-Meter Storage* project achievements, highlights key learnings from the project that have industry-wide value, and identifies future opportunities for PG&E to leverage this project.

CPUC passed two decisions that established the basis for this program. CPUC initially issued D.11-12-035, *Decision Establishing Interim Research, Development and Demonstrations and Renewables Program Funding Level,*[8] 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,*[9] 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."[10]

The decision also required the EPIC Program Administrators[11] 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 2.19c – *Customer-Sited and Community Behind-the-Meter Storage*. Through the annual reporting process, PG&E kept CPUC staff and stakeholders informed on the progress of the project. The following is PG&E's Final Report on this project.

3 Project Summary

The objective of EPIC 2.19c was to demonstrate distributed demand-side technologies and approaches to address local and flexible resource needs. Specifically, the project aimed to deploy an aggregation of third-party-owned BTM battery energy storage resources, and to demonstrate that aggregated BTM storage resources can be utilized by the utility to:

I. Reduce electric load during electric energy demand peak times.
II. Absorb distributed generation during solar generation peak production times.

3.1 Issue Addressed

Increased renewable penetration is resulting in a significant change in net load in California, resulting in low net demand around noon and high net demand in the evening - a load shape known as a "duck"

[8] http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/156050.PDF.
[9] http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/167664.PDF.
[10] Decision 12-05-037 p. 37.
[11] Pacific Gas & Electric (PG&E), San Diego Gas & Electric (SDG&E), Southern California Edison (SCE), and the California Energy Commission (CEC).

curve, shown in ***Figure 1***. There are a number of proposed solutions to this, including rate reform, and use of energy storage. Across California, there is growing use of and interest in energy storage, which can be either utility or customer sited. This project sought to understand customer interest in and adoption of BTM technologies, as well as the technical feasibility for deploying these batteries as a grid resource.

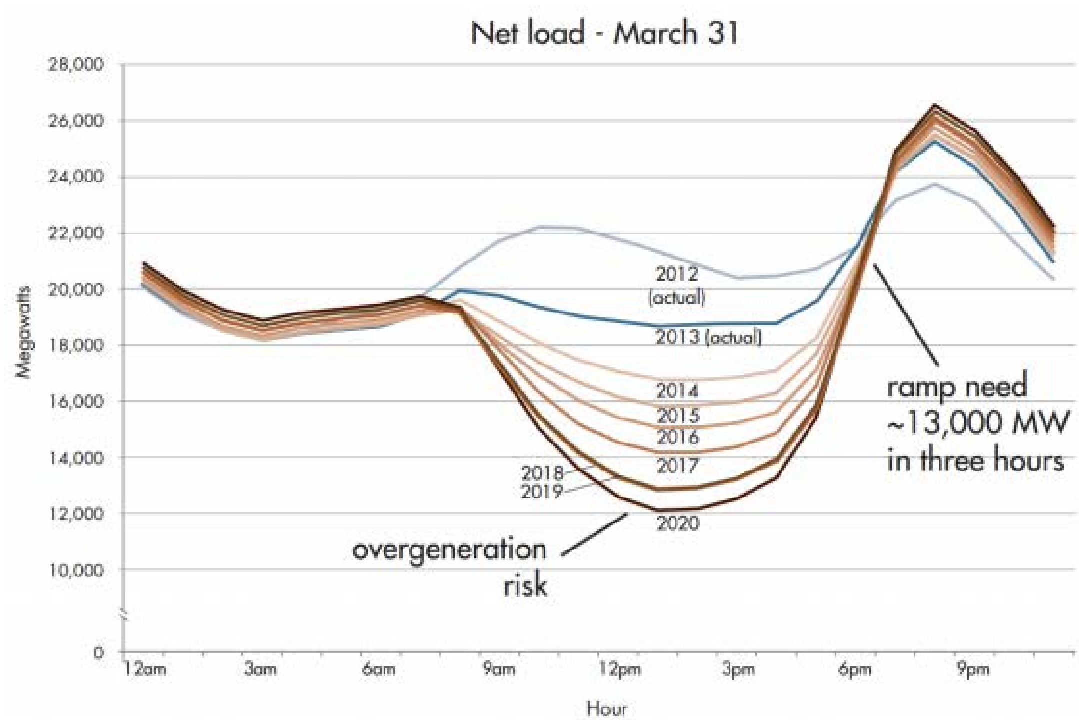

Figure 1: The CAISO[12] "duck" curve

Following utility scale energy storage solutions, customer-sited BTM energy storage technologies are emerging as a potential new tool for peak-load reduction during peak energy demand time periods, or storing excess solar generation during over-production time periods. Since these are relatively new technologies, utilities do not have extensive experience making use of aggregated BTM energy storage to serve operational grid needs, and many technical, financial, contractual, and organizational questions will need to be addressed prior to the use of this tool on a wider scale. These questions include:

I. Can the utility rely on BTM resources to provide the contracted distribution services?
II. How will the utility visualize and execute control over BTM resources?
III. What are the costs of deploying these technologies?

This project aimed to address these questions through a BTM storage deployment that can inform decisions about the effectiveness and use of this tool in future utility planning, especially during evaluation of option of non-wires solutions, such as customer BTM energy storage, as part of the IDPP. The project also served to inform energy storage procurement processes, as defined in AB 2514 and AB 2868. For these reasons, PG&E needs to be better informed about the customer-sited BTM energy storage technology readiness and improvement opportunities. This project provided valuable

[12] Source: California Independent Systems Operator (CAISO).

learnings related to use of customer-sited BTM energy storage technology in support of grid operations.

3.2 Project Objectives

To provide valuable learnings related to use of customer-sited BTM energy storage technology in support of grid operations, the following key objectives were set:

A. Evaluate the technical ability of BTM energy storage to **reduce peak loading** or absorb distributed generation on utility distribution feeder(s), with sufficient reliability for distribution grid operations
B. Clarify storage **technology and process requirements** to integrate and interoperate DERs to address grid needs, and characterize barriers to deployment at scale relative to today.
C. **Demonstrate and evaluate communications** available to provide DER visibility, monitoring, and control in order to address grid needs reliably today.
D. Evaluate the ability of BTM energy storage to **simultaneously provide services** to a utility and the on-site customer, correctly prioritizing distribution services.

3.3 Scope of Work and Project Tasks

The project team approached the problem statement by aiming to deploy and test aggregated, customer-sited energy storage.

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.[13] These options include the ability to reduce electric demand during peak demand time periods and absorb distributed generation during peak solar irradiance time periods in support of the distribution grid operation needs. In order to use such assets in operations, it was necessary that the project demonstrate the ability of customer-sited assets to effectively shape net load profile, reliably communicate and execute one or more functions, and accurately measure and report operational properties.

3.3.1 Tasks and Milestones

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

- Release request for offers (RFO) for commercial and residential battery storage vendors
- Develop joint marketing approach between vendors and PG&E
- Customer Acquisition
- Develop test use cases, test plan, and measurement & verification plan
- Test use cases in the field, and document and verify results.

Release RFO for commercial and residential battery storage vendors
The project team decided to conduct an open RFO, with clear minimum conditions, rather than a direct award contract. The decision to do a clear RFO with minimum requirements allowed for

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

competition among responders, while also reducing the number of responses that the project team had to review.

For this project, PG&E was very prescriptive with the vendors on project requirements and provided a structure around how to provide pricing, enabling an "apples to apples" comparison across vendors for pricing. However, for future projects, clearly detailing the requirements – but leaving less structure around pricing – could allow vendors to propose a more workable and perhaps creative solution that has proven successful for them in the past. With vendors providing achievable targets based on experience, PG&E could then consider a rewards/penalty clause for meeting goals within project timelines.

Value of minimum requirements for RFO bidders was confirmed: "lessons learned" from the 2014 Energy Storage RFO were applied in this project. PG&E significantly reduced workload of evaluating RFO responses by having a qualifying step in the form of a Contract Opportunity Announcement with clear minimum requirements for vendors. This approach was also beneficial to industry participants. Some vendors expressed their appreciation for the clarity on minimum requirements, which saved them the time and expense of submitting an offer that had little chance of success.

PG&E ultimately selected two vendors: one for commercial assets and one for residential assets. The selected commercial vendor had a Letter of Intent from one commercial customer prior to the start of the project. This Letter of Intent scored additional points for the vendor during the selection process. The residential vendor was already participating on the ongoing PG&E EPIC 2.03 project, so some "economies of scale" were expected to benefit the EPIC 2.19 project, especially with a free ESS offering to new solar customers. Other considerations for vendor selection included a vendor's customer acquisition plan, software capabilities, and pricing.

Learning – Clear Guidelines and Requirements Benefit the RFO Process

Clear guidelines and requirements in the RFO (essentially a Scope of Work) helped to streamline contract negotiation post vendor selection. In PG&E's case, the bulk of the contract negotiation was related to Legal Terms and Conditions rather than Statement of Work (SOW) content.

Develop joint marketing approach between vendors and PG&E

Several marketing approaches were considered, as shown in ***Figure 2***. The project team ultimately decided on a "vendor-led, PG&E-supported" approach to customer marketing because many of the vendors expressed expertise and confidence in their acquisition capabilities. PG&E was willing to co-brand marketing materials with the vendors.

After the "vendor-led, PG&E-supported" approach was selected, PG&E and vendors agreed on roles and responsibilities, as presented in ***Figure 3***.

Less PG&E engagement — Recommended — More PG&E engagement

Options	A) Fully outsourced	B) Vendor-led	C) PG&E-led	D) PG&E only
Description	Vendor engages with customers and delivers PG&E with DER capacity. PG&E has no involvement with customer experience.	PG&E helps shape the message and approve all co-branded materials. Operationally, the vendor makes contact with customers.	PG&E develops and approves all co-branded materials. Operationally, PG&E makes contact with customers.	PG&E engages customers directly and owns the customer experience.
Collateral development	Vendor	Vendor	PG&E	PG&E
Co-branding	No	Yes	Yes	No
Ability to enroll customers	• absence of PG&E brand may create customer distrust • leverages vendor's customer acquisition capabilities	• co-branding may legitimize the program in customers' eyes • leverages vendor's customer acquisition capabilities	• see B)	• customer may question PG&E's motives
Meet project timelines	• fastest path to market	• compatible with the projects' timeline but additional effort required to review/co-develop marketing plan and co-branded collateral	• collateral development by PG&E likely to result in delays extending proposed pilot timelines	• unlikely PG&E can move fast enough autonomously or put forth enough personal touch resources to meet pilot timelines
Opportunities for positive brand impact	• limited opportunities for brand positive news (e.g. can't say PG&E takes community solar)	• PG&E has some degree of control on the message and may capitalize on PR/brand opportunities	• PG&E has even stronger control over the message	• PG&E has full control over message and can develop preferred PR/brand approach independently
Risk management	• customer protection: limited ability to shape the message the vendor uses with customer	• brand: limited brand exposure • customer acquisition: if involved in designing customer acquisition strategy, PG&E may share some performance risk	• see B)	• customer acquisition: PG&E seen as "big brother" and/or interfering with solar • brand: full brand exposure • legal risk: potential direct contract with customer

Figure 2: Considered Marketing Approaches

	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 contracts 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.

Figure 3: PG&E and Vendors Roles and Responsibilities

Customer Acquisition

PG&E contracted energy storage vendors to conduct primary customer acquisition activities and negotiate contracts with customers participating in the technology demonstration projects. Energy storage vendors conducted all activities to install and obtain interconnection approval of BTM energy storage systems, provided an aggregation platform for PG&E to utilize for monitoring and control of BTM energy storage assets, and provided continued monitoring support throughout the technology demonstration project. PG&E Marketing provided branding support and approved customer engagement approaches. The project targeted 500 kW/4 hr. of which 164.8 kW/4 hr. (33 percent) was deployed (shown in ***Table 3***).

Table 3: Deployment of EPIC 2.19c BTM storage assets (As of 8/9/2017)

	# Sites	# Batteries	kW/ 4hr	Target Max	Target Min	% Max Achieved
1. Residential Total	27	47	66.3	180	150	37%
1a.Single Battery Home	*13*	*13*	*20.8*			
1b. Double Battery Home	*10*	*20*	*32*			
1c. Second Generation System	*4*	*8*	*13.5*			
2. Commercial Total	3	12	360	360	350	100%
Total	**30**	**53**	**426.3**	**540**	**500**	**68%**

This project was co-located with EPIC 2.03 Test Smart Inverter Enhanced Capabilities - Photovoltaics (PV) and EPIC 2.02 Technology Demonstration Distributed Energy Resource Management Systems (DERMS) on a distribution feeder located in San Jose, CA. All three projects shared these field resources.

Develop test use cases, test plan, and measurement & verification plan

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

1. Net Load Management – The main use of BTM energy storage devices is expected to be the reduction of peak load or absorption of peak generation in support of grid operation needs.
2. Reliable and Prompt Response – Effective use of BTM energy storage resources require an accurate and reliable response from the asset, following PG&E dispatch request signals.
3. Provide Service to Utility and Customer – In addition to providing the distribution and transmission grid service, it is expected that BTM energy storage devices will simultaneously provide services to the end customer. If vendor systems provide multiple functions, response to utility requests should be reliable at all times.
4. Meter Accuracy – BTM energy storage vendors are expected to accurately measure and report measurements. As BTM resource aggregations become more widespread, payments for their services may be settled based on the aggregator's metering equipment.

Prior to operating assets in the field, PG&E developed a test plan consisting of several tests for each of the use cases noted above. A detailed list of test cases, developed as part of the test plan, is shown later in ***Methods*** (Section 3.6). The test plan was developed to enable and allow for measurement and verification (M&V). Also, based on the test data available, PG&E created a M&V plan that would allow PG&E to quantify and/or qualify both vendor systems' performances.

Field Trial and M&V
As part of the field trial, testing was performed on 20 residential and 2 commercial BTM energy storage systems.[14] Results of the tests and corresponding M&V analyses are presented in Section 4 Technical Results and Observations.

3.4 Project Activities

The BTM assets in this project were tested in the field from July to October 2017. The field testing targeted the four use cases, described in detail below.

Use Case #1: Net Load Management
One of the core objectives of the EPIC 2.19c BTM storage technology demonstration was to determine if aggregated customer-sited BTM energy storage resources can be reliably used to reduce peak load or store excess generation, per utility request. BTM storage can reliably operate in support of net load management processes, distribution planners can leverage BTM storage solutions as a potential NWA to address electric grid needs (e.g., distribution grid capacity). NWA solutions are a potential alternative to a more traditional utility approach for the same purpose, such as replacing transformers and/or re-conducting lines.

During peak usage periods, usually summer months, loading on some utility distribution feeders can approach or exceed the rated capacity of those feeders. Emerging energy storage technologies located behind customer meters represent a potential new tool for peak-load reduction or storing excess-production of DERs. Field testing was conducted to determine if BTM storage resources are able to consistently and effectively reduce load on the distribution feeder between the hours of 16:00 and 20:00, as well as to absorb locally produced solar power, if present on site.

To evaluate technology readiness in support of this use case, the following tests were conducted:

- **Inverter Kilovolt-Ampere (kVA) Limits -** Evaluate that the battery systems can achieve their nameplate rated output limits.
- **State of Charge (SoC) -** Assess the energy storage aggregator's ability to provide a certain battery SoC at a certain time of day. To evaluate this capability, a low SoC was required in the morning to absorb excess solar generation during the day and a high SoC was required in the late afternoon to service the evening load increase demonstrated in figure 1.
- **Load Shift -** Evaluate the aggregator's ability to consistently supply during a 4-hour window that coincides with peak summer demand. This test was conducted in sequence with Test #2 - the battery was charging during high solar production hours to reach the desired SoC by 16:00.
- **Flexibility Forecast -**Evaluate the aggregator's ability to accurately report their flexibility forecast, the amount of energy available to charge and discharge, if needed. The commands to discharge were issued when aggregators reported discharge flexibility. Inaccurate flexibility forecast may result in dispatch requests that cannot be delivered if called upon.
- **Weather vs. Performance -** Evaluate if ambient temperature has an impact on battery output performance.

[14] Due to the implementation and deployment challenges discussed, some assets were not available for testing. The technical and testing results discussed throughout the rest of the report are based on the assets available for testing.

- **Load Profile -** Examine change in a customer's net load profile as a result of a BTM battery system operation.
- **Charge from Solar -** Evaluate if battery systems with attached solar generation system can be charged entirely from local BTM solar generation sources over the course of a day.

Use Case #2: Reliable and Prompt Response
This use case addressed responsiveness and latency of dispatched BTM storage signals.
One of the objectives of this project was to demonstrate communications with aggregate resources for visualization and control. This included testing integration with the Distributed Energy Resource Management System (DERMS) being demonstrated under the EPIC 2.02 project. The purpose of this use case was to demonstrate that dispatch signals can be quickly and accurately sent from PG&E to the storage aggregator and from the aggregator to the individual asset, resulting in an accurate and reliable response from the asset. This use case provides insight into the average time lag between these communication steps (latency), and how frequently the vendor experiences a loss of communication with an asset that could potentially impact asset performance (uptime).

The following tests were conducted to support this use case:

- **Communication Loss** - This test evaluated the recovery time required when communications is lost. A single scenario with a high probability of occurrence was tested with each aggregator:
  - Residential vendor: the customer's home router being reset.
  - Commercial vendor: loss of cellular signal.
- **Communications Reliability (Uptime)**- This is not a specific test. It is an analysis of all the data records over the entire demonstration test period. Both aggregators reported an "Online" or "Offline" status in the data record which was used to evaluate communication uptime. The results of this test are shown both over the course of the demonstration, and over a "steady-state" period, or the last 30 days of operation.
- **Latency** - This test evaluated how long it takes for a command to execute. The latency of three types of commands were tested:
  - Commands that are previously scheduled;
  - Commands that are executed in real-time when the battery is in an active (charge or discharge) state;
  - Commands that are executed in real-time when the battery is in a an idle (no charge or discharge) state.

Use Case #3: Provide Service to Utility and Customer
This use case explored the opportunity for resources to simultaneously provide grid services in addition to reducing customer peak demand charges.

BTM storage assets can provide the greatest amount of stacked benefits by providing services to the end customer in addition to the distribution and transmission grid. End use customer benefits could include, but are not limited to reducing customer bills and providing services (e.g. backup power). For example, commercial vendors storage systems in this technology demonstration were designed primarily for bill management via demand charge management and optimization of time of use rates. The purpose of this use case was to understand how well these storage assets provide value to customers through storage vendors' in-house algorithms designed to maximize customer bill savings while also providing PG&E with the operational grid benefits of reducing peak load – or, in a high-renewable penetration scenario, providing increased load.

The following tests were conducted to support this use case:

- **Multiple Functions -**This test evaluated aggregator ability to execute more than one non-exclusive function at the same time. For the commercial vendor, the first function was to maintain a minimum SoC so the asset could be called upon with short notice for load deferral. The second function was the commercial vendor's normal customer function (peak demand reduction). This test does not apply to the residential vendor because the only intended use of the battery system is customer backup power. The residential vendor does not currently use the batteries for any other function.
- **Dynamic Constraints -** This test evaluated the aggregator's ability to perform its normal customer functions with constraints on maximum charge and discharge power, which can be changed by the utility. This test does not apply to the residential vendor because the only intended use of the battery system is customer backup power. The residential vendor does not currently use the batteries for any other function.

Use Case #4: Meter Accuracy
This use case calls for accuracy of the metering values provided by energy storage aggregators.

As BTM resource aggregations become more widespread, payments for their services may be settled based on the aggregator's metering equipment. This technology demonstration provided a unique opportunity for PG&E to directly meter storage asset output through Power Quality Meters, and compare these values to those provided by the aggregator's metering equipment to understand the magnitude, direction, and persistence of any metering variances, and ascertain the feasibility of using third-party metering for future billing and settlement purposes.

The following test was conducted to support this use case:

- **Metering Validation -** This test evaluated the accuracy of the aggregator's metering and whether or not the aggregator's metering is appropriate for remuneration.

3.5 Technical Development and Test Methods

Two energy storage configurations – residential and commercial - were deployed in the field. Wherever applicable, the project applied identical field trial test methods to both residential and commercial vendor assets.

3.5.1 Residential BTM System Configuration

As presented in ***Figure 4***, each residential system consisted of a communication gateway, inverter, PV array, and one or two batteries. The inverter nameplate rating was 7.6 kW and 8 kVA. One battery nameplate rating was 3.3 kW Direct Current (DC) and 6.4 kilowatt-hour (kWh) DC, with 0.25 kWh capacity held in reserve (two batteries were rated at 3.3 kW with 12.8 kWh). Each battery had an integrated thermal management system. 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 the inverter. The inverter was connected 240 V line-to-line at the residential customer's main panel. In addition to the main panel connection, the inverter was 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 inverter and the main panel breaks, and the inverter operates in islanding mode providing service to the critical load panel.

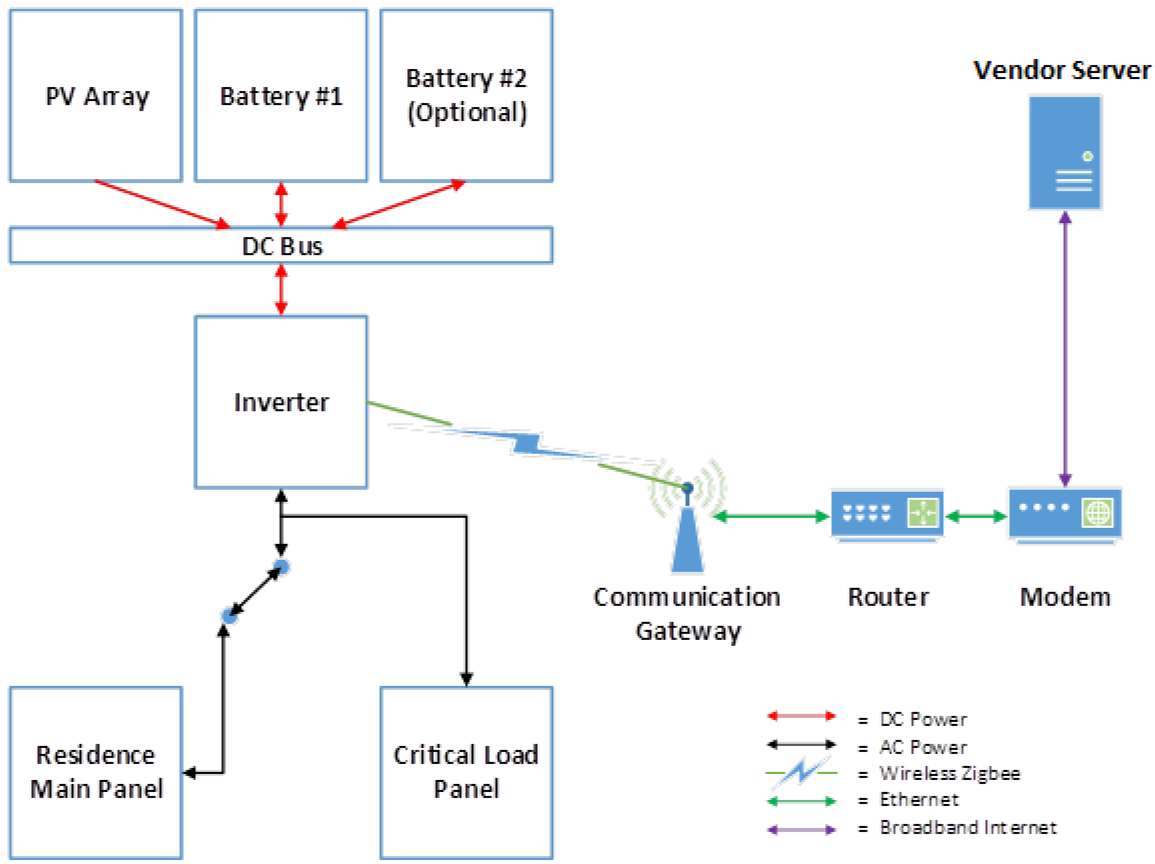

Figure 4: Residential BTM system configuration

The user interface to the battery command scheduling system was a web-based application, which allowed PG&E to manually issue commands in real-time or schedule commands for execution. Additionally, PG&E was able to schedule multiple commands through the web application by uploading a specifically formatted comma separated value (CSV) file. PG&E had flexibility to schedule commands at the low (asset/customer) level or at higher (aggregation nodes) levels. There were a total of 5 levels of aggregation nodes, with the highest-level accounting for all residential assets participating in the technology demonstration project. Scheduled commands at an aggregation node were re-distributed to all assets under that node and that node's sub-nodes.

Residential BTM storage vendor servers sent scheduled commands 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 to the inverter when the time to execute the command came. The inverter then sent the commands to the battery. For the systems with two batteries, only one battery was used at a time. Compared to a single battery configuration, two battery system configurations had double the energy capacity, but the same power capacity. The inverter managed which battery operated on any given command.

The residential BTM energy storage vendor system collected data from sites at an approximate 10-second interval. 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 sufficient granularity of data to evaluate operation of the systems in the field – this was R&D, not an operational requirement for the production scale.

3.5.2 Commercial BTM System Configuration

As presented in ***Figure 5***, each system consisted of four towers (stacked battery modules), a site master controller, and a cellular modem. Each tower had a battery stack, an inverter, and an Heating, Ventilation and Air Conditioning (HVAC) system for thermal management. The towers were rated for 30 kW and 60 kWh, and each tower was paralleled at a panel to bring the full system size to 120 kW and 240 kWh. The overall system capacity was de-rated (~10%) to account for capacity that was held in reserve. The inverters were 3-phase, capable of operating at 208 V or 480 V. The systems used in this project were connected to 208 V.

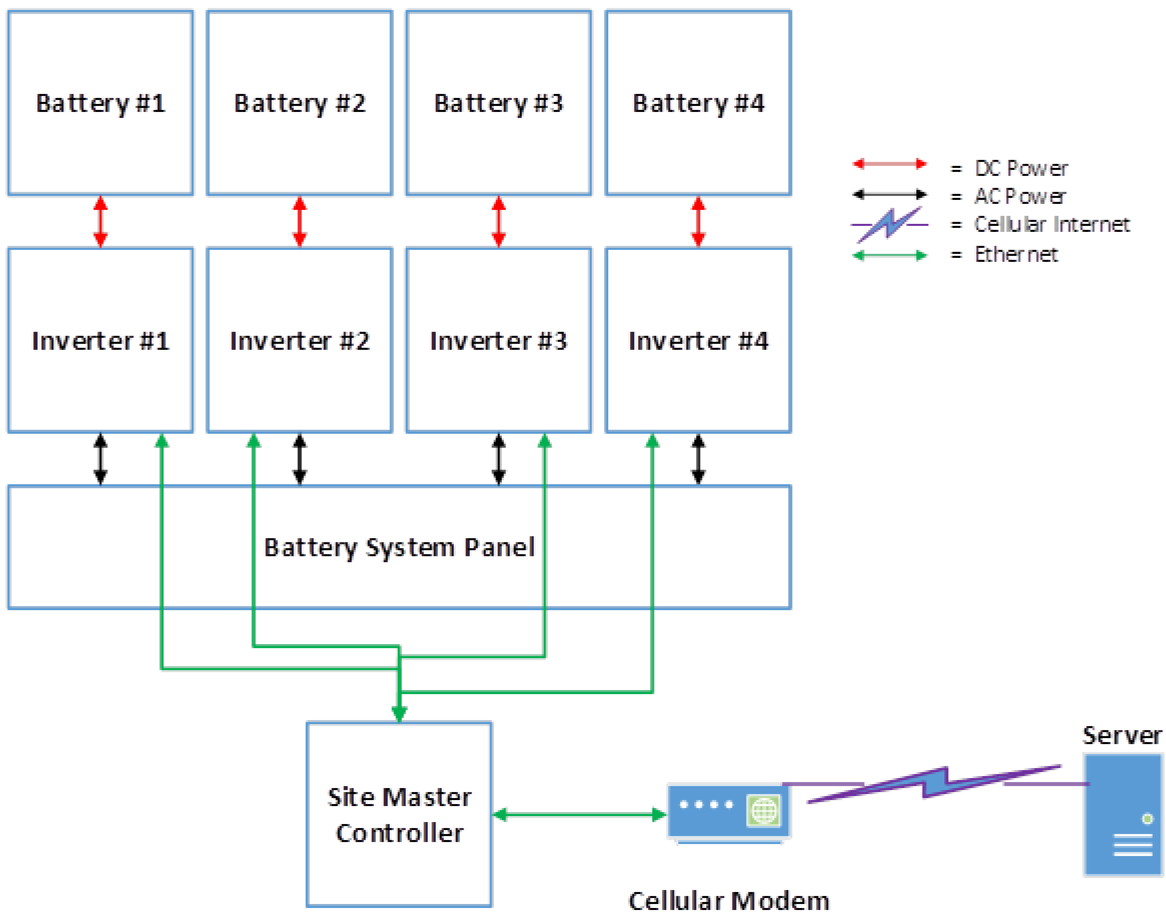

Figure 5: Commercial BTM system configuration

The user interface to the battery command scheduling system was a web application. Commands were submitted manually in real-time or scheduled to execute at some time in the future. Also, the web application allowed for commands to be scheduled to repeat daily, weekly, monthly, or yearly. Commands were applied on the aggregations nodes, treated as virtual power plants - any power command is divided among the systems in the aggregation with no guarantee of the power output of any single system in the aggregation, but all the systems in aggregate execute the commanded power.

Scheduled commands are sent to the site master controller. The site master controller connects to the commercial BTM energy storage vendor servers via the cellular modem. The site master controller stored the schedule and sent the commands to the inverters when time to execute.

The commercial BTM energy storage vendor collects data from the inverters in a 1 second interval. During the communication outage, the data would be stored at the site and sent to the commercial BTM energy storage vendor server when communication is reestablished. Data was reported to PG&E in a 5-minute interval. Power, voltage and current were averaged through the 5-minute interval and timestamped at the beginning of the 5-minute interval.

3.6 Methods

A total of thirteen tests were scoped. The project aimed to optimize execution of tests by combining compatible tests (e.g., Test #2 and #3). As shown in Figure 4 and Figure 5 the project made some assumptions and set outcome expectations for each of the scoped tests. A list of residential and commercial assets and corresponding tests executed during the project is shown in ***Table 4*** and ***Table*** 5, respectively.

Test Assumptions and Expected Outcome

Test #	Test	Assumptions	Variables	Expected Outcome
Use Case #1: Net Load Management				
1	Inverter kVA Limits	Ability to schedule real and reactive power simultaneously.	kVA, kW, kilovolt-ampere-reactive (kVAR)	The battery systems were expected to be able to import and export real and reactive power at their kVA limit.
2	State of Charge	Accurate reporting of SoC. Ability to schedule real power.	SoC, Time	• SoC ~ 20% at 10:00. • SoC ~ 100% at 16:00.
3	Load Shift	Ability to schedule real power.	kW, Time	Battery system: • charged between 10:00 and 16:00. • discharged between 16:00 and 20:00.
4	Conflicting Request	Ability to: • Schedule real power. • Observe flexibility forecast in DERMS. • Schedule in DERMS.	kW, Time	Asset is expected to show no flexibility in the 2 hours before the scheduled discharge.
5	Weather vs. Performance	Ability to schedule real power. Sufficient range of ambient temperature through the testing period.	Ambient temperature, kW, Time	The performance of the systems should be similar to their stated efficiencies. There is no expectation on how the performance will change with temperature. This is exploratory.

Test #	Test	Assumptions	Variables	Expected Outcome
6	Load Profile	Peak-shaving algorithm operating properly.***	kW, Time	A flatter load profile is expected with the battery systems.
7	Charge from Solar	Ability of inverter to manage charging so it is limited to solar production.**	kW from PV, Battery, and Inverter	The battery system expected to be able to fully charge from solar.
Use Case #2: Reliable and Prompt Response				
8	Communication Loss	Ability to create a loss of communication event.*	Time	None
9	Communications Reliability	Vendors to report when comms are lost.*	Time	None
10	Latency	Vendors can provide sub 1-minute interval data.*	Time	None
Use Case #3: Provide Service to Utility and Customer				
11	Multiple Functions	Adjust the floor SoC***	kW	The peak-shaving algorithm is expected to run but not let the system SoC drop below 50%.
12	Dynamic Constraints	Automatically adjust max charge/ discharge***	kW	The peak-shaving algorithm is expected to run but not let the system power go outside the specified limits.
Use Case #4: Metering Accuracy				
13	Metering Validation	Ability to install power quality meter (PQM) at commercial vendor site.	kW, kVAR, Voltage	Compared to PQM measurements, the battery system measurements were expected to deviate less than 2%.

* – Exploratory Test.
** – Applies to residential BTM energy storage vendor only.
*** – Applies to commercial BTM energy storage vendor only.

Table 4: Residential BTM Energy Storage Site List

Commissioning Date	DC Solar Size (kW)	DC Battery Size (kW)	DC Battery Capacity (kWh)	Tests Executed
9/22/2017	7.56	3.3	6.4	2, 3, 6, 7, 9
9/22/2017	8.50	3.3	6.4	7, 9
9/22/2017	4.24	3.3	12.8 (6.4 Used)	9
7/1/2017	3.92	3.3	12.8 (6.4 Used)	1, 2, 3, 6, 7, 9, 10
9/22/2017	3.38	3.3	6.4	2, 3, 6, 7, 9
9/22/2017	5.46	3.3	12.8 (6.4 Used)	7, 9
8/10/2017	3.38	3.3	6.4	7, 9, 10
8/10/2017	6.24	3.3	6.4	7, 9, 10
7/12/2017	3.38	3.3	6.4	1, 7, 9, 10
9/22/2017	5.04	3.3	12.8 (6.4 Used)	2, 3, 6, 7, 9
9/22/2017	6.24	3.3	12.8 (6.4 Used)	7, 9
8/10/2017	8.19	3.3	12.8 (6.4 Used)	4, 7, 9, 10
9/22/2017	4.16	3.3	6.4	7, 9
10/6/2017	4.42	3.3	12.8 (6.4 Used)	7, 9
7/12/2017	3.12	3.3	6.4	1, 6, 7, 9, 10
7/12/2017	2.60	3.3	12.8 (6.4 Used)	1, 2, 3, 6, 7, 9, 10
7/12/2017	2.60	3.3	6.4	1, 2, 3, 5, 6, 7, 9, 10
7/1/2017	4.16	3.3	6.4	1, 6, 7, 9, 10
8/10/2017	2.86	3.3	6.4	2, 3, 6, 7, 9, 10
10/6/2017	2.86	3.3	6.4	7, 9

Table 5: Commercial BTM Energy Storage Site List

Commissioning Date	Alternating Current (AC) Battery Size (kW)	AC Battery Capacity (kWh)	Test Executed
7/6/2017	120	240	1, 2, 3, 5, 6, 8, 9, 10, 11, 13
7/6/2017	120	240	4, 9

3.7 Challenges

The main challenges encountered by the EPIC 2.19c project can be grouped in stages as follows:

- Customer Acquisition
- Construction of Assets
- Permitting & Interconnection
- Asset Commissioning & Site Acceptance Testing

<u>Customer Acquisition</u>

The project team was ultimately surprised that the majority of the challenges were attributed to getting assets into the field, which resulted in project delays. Both residential and commercial BTM energy storage vendors had a difficult time acquiring customers to deploy energy storage units on two selected feeders. The customer acquisition targets and achieved results were as follows:

- Residential Vendor:
  - Targeted: up to 150 kW for 4 hours.
  - Achieved: 64.8 kW for 2 hours.
- Commercial Vendor
  - Targeted: 350 kW for 4 hours.
  - Achieved: 240 kW for 2 hours

Customer acquisition for both vendors was 2 to 4 months behind schedule, which extended and further complicated execution of all three (EPIC 2.19c, EPIC 2.03 and EPIC 2.02) projects. In part, the shortfall on customer acquisition targets can be attributed to the fact that customer acquisition was not the primary driver in the feeder selection process. The feeder selection process aimed to satisfy the needs of three EPIC projects, sharing DERs.

There are many reasons why customer acquisition was challenging for the San Jose DER technology demonstration projects. The key reasons include: vendor lack of access to customer information, customer solar fatigue, improper incentives, and lack of clear strategy. Furthermore, there was misunderstanding of what existing solar system inverters can be retrofitted, because most of the existing residential vendor's solar lease contracts prohibited solar generation curtailment (one of EPIC 2.03 project use cases). Some of these issues could have been mitigated, but many could not – ultimately having a clear strategy and allowing adequate time in the project timeline would have removed some of the hurdles.

Learning – Identify and Account For Customer Acquisition Risks

Vendors struggled to acquire customers due to a combination of issues: limited access to customer information, customer fatigue from door-to-door solar, unclear equipment retrofit outcome, and shifting customer engagement strategies, to name a few. The project learned that customer acquisition risks should be more heavily weighted to establish more realistic timelines and projected outcomes for BTM NWA projects, which are very sensitive to time, quantity and location of the resource's deployment.

Next Step – Right Customer Acquisition Targets for Right Vendors in Right Areas

Challenges in achieving customer acquisition targets for each vendor may have been due to a variety of circumstances, such as customers' with existing solar system having restriction on testing rights, the customer engagement strategy, and customer fatigue from door-to-door solar sales. One project learning is that customer acquisition risks should be identified and accounted for upfront to establish more realistic timelines, particularly when targeted deployment of DERs is required for safe operation of the grid (e.g. as part of a non-wires alternative capacity project).

Next Step - PG&E May Want or Need To Take Greater Role in Customer Acquisition

Although PG&E facilitated the development of co-branded marketing collateral to ensure consistent messaging and help drive efficiencies between the vendors, the vendors utilized their own platforms and resources to develop the actual materials. PG&E's role was to vet, approve, and signoff on all materials prior to the vendor releasing them to the public. There was good collaboration between the parties and assurance that the materials met PG&E's approved marketing guidelines. For future projects that involve customer acquisition, future teams should consider working with PG&E to evaluate past marketing efforts, to vet customer acquisition strategy, and to determine whether PG&E should take on specific tasks or lead customer acquisition efforts.

Construction of Assets

Once customers were acquired, installation of assets in the field faced challenges related to:

- Delays with subcontractor deliverables
- Fire safety
- Location of coolant system in design
- New battery and power management system

Permitting and Interconnection

Permitting and Interconnection activities for the customers were more challenging than expected. Prior understanding of requirements and experience on PV-only timelines did not translate to this project. Some permitting and interconnection challenges are listed below:

- Length of time required for solar plus storage interconnection (8-27 weeks to interconnect).
- Lack of standardized, streamlined permitting process for solar plus storage installation – City of San Jose's inexperience with permitting storage systems; as a new technology, the city had limited experience with the technology and processing permits. Given the lack of experience, and each permit being addressed individually, nothing was "fast tracked" or batched.
- Weight of wall-mounted energy storage system required structural drawings.
- Additional (and unexpected) fire safety review for commercial energy storage installations.

Learning – Understand Regulatory and Engineering Requirements to Bring Assets Online

For DERs, it is crucial to understand the regulatory and engineering requirements to bring assets online. Vendors and PG&E have both streamlined activities for solar interconnection process. However, neither the vendor nor PG&E anticipated the length of time required for solar plus storage interconnection. PG&E is currently working with storage vendors today to streamline its interconnection process.

Learning – Account for City and Local Jurisdiction Permitting Requirement Complexities

Cities and AHJ's often have their own sets of requirements. To properly set expectations, the project plan needs to account for these complexities. While both the City of San Jose and the residential vendor had permitted storage before, it is not standardized. As a result, the process required multiple rounds of inspections and additional engineering details that were not required for solar-only interconnection permitting.

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 ESS readiness for PG&E site acceptance testing and 2) PG&E site acceptance testing to verify ESS readiness for use case demonstration. Both of these activities should have been a simple 'check-list' process, but have proven to be challenging and were completed on a longer than anticipated timeline.

During the commissioning process, both the vendors and PG&E exposed additional issues that should have been captured in early testing. Further, tests that passed for the vendor often failed for PG&E's requirements for communication and technology reliability. Some key challenges are listed below, some of these challenges were resolved throughout the course of the demonstration and some were not:

- Communications
    - Intermittent communication was affecting command execution
    - Protocols used for asset communication include Zigbee and residential internet, both of which experienced functionality issues during the demonstration.
    - One of the sites had two batteries, and it was found that the inverter was only communicating with one of the two batteries
- Missing data
    - Data reporting was incorrect when battery towers tripped offline
    - During the acceptance testing, days of data were missing from multiple assets
- Problems bringing/keeping assets online
    - At multiple sites, battery towers were unavailable for testing
    - The battery stacks would trip off in the middle of testing
- Assets not executing commands
    - Partial execution of scheduled commands – all real power commands executed, but only half of the reactive power commands executed
    - At sites with two batteries, second battery performance was uncertain and resolution posed risks on project execution timeline; had to be disabled

Learning – More Testing 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 of this project. This suggests that vendor systems needed more testing by vendors before being handed over to PG&E for the site acceptance testing. This would reduce start-up and ramp- up times.

4 Technical Results and Observations

In collaboration with the BTM ESS technology providers, PG&E successfully completed 12 tests. Grouped by the use case, the sections below describe the tests, test results, takeaways, and next steps.

4.1 Use Case #1 Net Load Management Test Results

This section summarizes the test results that correspond to Use Case #1: Net Load Management, addressing one of the key objectives of this project.

4.1.1 Inverter kVA Limits

The test results prove that the battery systems can achieve their rated output limits, verifying technology readiness to deliver full apparent power. The commercial BTM energy storage system

could operate at its KVA limit while outputting both active and reactive power. Active and reactive power set points and system response graphs are shown in Appendix A.1.1.
Although the expectation was to be able to schedule both active and reactive power simultaneously, the project was not able to schedule such a scenario at the residential BTM energy storage sites due to asset management platform limitation to schedule fixed reactive power output while the battery charges/discharges active power. While PG&E had not provided this requirement to the vendor in advance, the ability to schedule both active and reactive power simultaneously is considered a fundamental and is expected to be used in operations. This functionality is enabled with the partner project, *EPIC 2.03a Customer Sited Smart Inverters*, so the project team assumed that the same functionality would be enabled for the paired storage system.

Takeaway – Requirements Should Be Timely Coordinated Internally and Provided to Vendors
Active and reactive power settings are expected to be a key functionality moving forward and vendors should implement this into their systems. However, technical requirements should be internally coordinated and provided to the vendors in a timely manner, especially when multiple projects are collocated and leverage the same assets. With individual project requirements in place, vendors may be time constrained to make adjustments per all requests in a short time.

4.1.2 State of Charge

Both residential and commercial BTM energy storage vendor systems successfully followed scheduled charge and discharge commands, as shown in ***Figure 6*** and ***Figure 7*** (Battery State of Charge graphs).

Both vendors defined state of charge and available storage capacity differently. One vendor defined the metric as based on total energy within the system, and the other vendor marketed their offering as *usable* capacity. Since Lithium-Ion batteries (like those used in this technology demonstration) need to keep a constant reserve, the total battery capacity is not the total usable capacity. Consistent and clear definitions of both state of charge and marketed usable capacity will be important for future operations.

Residential Sites
The SoC test was executed simultaneously on seven residential sites for 14 days. The scheduled charge/discharge commands to achieve desired setpoints are shown in ***Table 6***. The intent was to achieve 20% and 100% battery SoC at 10:00 and 16:00, respectively. To achieve the 20% SoC at 10:00, the battery was commanded to discharge (3.3 kW per hour) at 00:10 and charge (1 kW per hour) at 05:00 for 1.25 hours (no command given until 10:00). At 10:00, the battery was charged again (1 kW per hour) to achieve a full SoC at 16:00. At 16:00, the battery was discharged (also part of Test #3) to achieve a fully discharged battery state at 20:00. At the request of the residential BTM energy storage vendor, the battery was then charged to approximately 50% SoC, reserved to backup critical loads in case of any power outage conditions overnight.

Table 6: Residential BTM Commands for SoC and Load Shift Tests

Start Time	End Time	Real Power Direction	Real Power Setpoint
00:10	05:00	Discharge	3.3 kW
05:00	06:15	Charge	-1 kW
10:00	16:00	Charge	-1 kW
16:00	20:00	Discharge	1.6 kW
20:00	21:00	Charge	-3.3 kW

The results showed that all tested assets, except for one, maintained their SoC as expected – low SoC (between 20% and 25%) and high SoC (at 100%) at 10:00 and 16:00, respectively. The one asset that failed to maintain the desired SoC experienced communication issues, further discussed in Section 4.9.

As shown in ***Figure 6***, the battery discharge was limited to about 0.25 kW (about 4%) to protect the battery from damage that can occur at a 0% SoC. The 1.25 kW charge command at 05:00 was intended to bring the SoC to 20%. A more granular information per tested asset can be found in the Appendix 1.2.

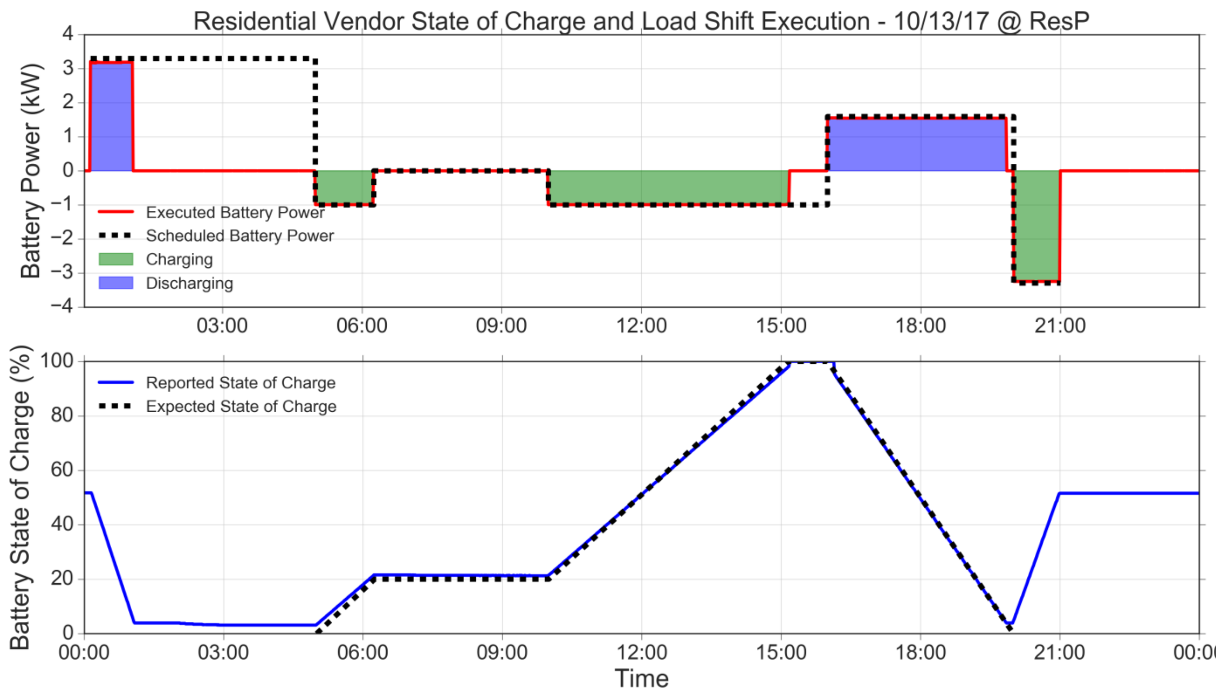

Figure 6: Residential BTM Battery Power and SoC

During field asset acceptance testing, it was discovered that the dual battery systems were not responding to charge commands as expected. Occasionally at the sites with two batteries, one battery would fully charge before the other battery. When this occurred, a "full charge" flag sent from a fully charged battery to the controller would result in controller ceasing charge commands to both batteries. Because of this, one of the batteries in the dual battery systems was disabled while the other one was charging. The challenge of balancing SoC across multiple batteries has also been observed with utility scale energy storage technologies that implement multiple DC string configurations and the strings have imbalanced SoC.

Takeaway – More Cooperation Among Energy Storage and Equipment Vendors Needed
The inverter manufacturers' control algorithms should be more transparent to energy storage vendors, and energy storage vendors should be more familiar with inverter control algorithms. Information exchange among vendors will help further enable reliable operation of systems, especially when firmware changes take place.

Commercial Sites

The SoC test was executed on one commercial site for 14 days. The scheduled charge/discharge commands to achieve desired setpoints are shown in ***Table 7***, and corresponding battery power and SoC measurements in ***Figure 7***. The intent was to achieve 20% and 100% battery SoC at 10:00 and 4:00, respectively. To achieve the 20% SoC at 10:00, the battery was commanded to fully discharge (at the rate of 120 kW per hour) at 00:00, then commanded to charge at 03:00 at the rate of 48 kW for 1 hour (0 kW command was given at 04:00 until 10:00 to suppress the peak shaving algorithm). At 10:00, the battery was charged again to achieve a full SoC at 16:00. At 16:00, the battery was discharged (also part of Test #3) to achieve a fully discharged battery state at 20:00. At 20:00, the battery immediately started charging to allow the commercial BTM energy storage vendor, if needed, to exercise a peak shaving algorithm that helps the customer avoid demand charges.

Table 7: Commercial BTM Commands for SoC and Load Shift Tests

Start Time	End Time	Real Power Direction	Real Power Setpoint
00:00	03:00	Discharge	120 kW
03:00	04:00	Charge	-48 kW
04:00	10:00	N/A	0 kW
10:00	16:00	Charge	-50 kW
16:00	20:00	Discharge	60 kW

The results showed that the tested asset maintained the SoC as expected – low SoC (around 27%[15]) and high SoC (at 107%[16]) at 10:00 and 16:00, respectively. The SoC was always 7% to 9% greater than the targeted SoC, because this commercial BTM energy storage vendor sets the minimum SoC at 7%. During testing, a discrepancy in the SoC reporting was found. On one of the test days from about 14:00 to 17:00, the asset reported SoC plateaus even though the reported battery power was not 0. More details on this finding can be found in the Appendix A.1.2.

[15] Min required charge of 7% plus 20% of discharge capacity.
[16] Min required charge of 7% plus 100% of discharge capacity.

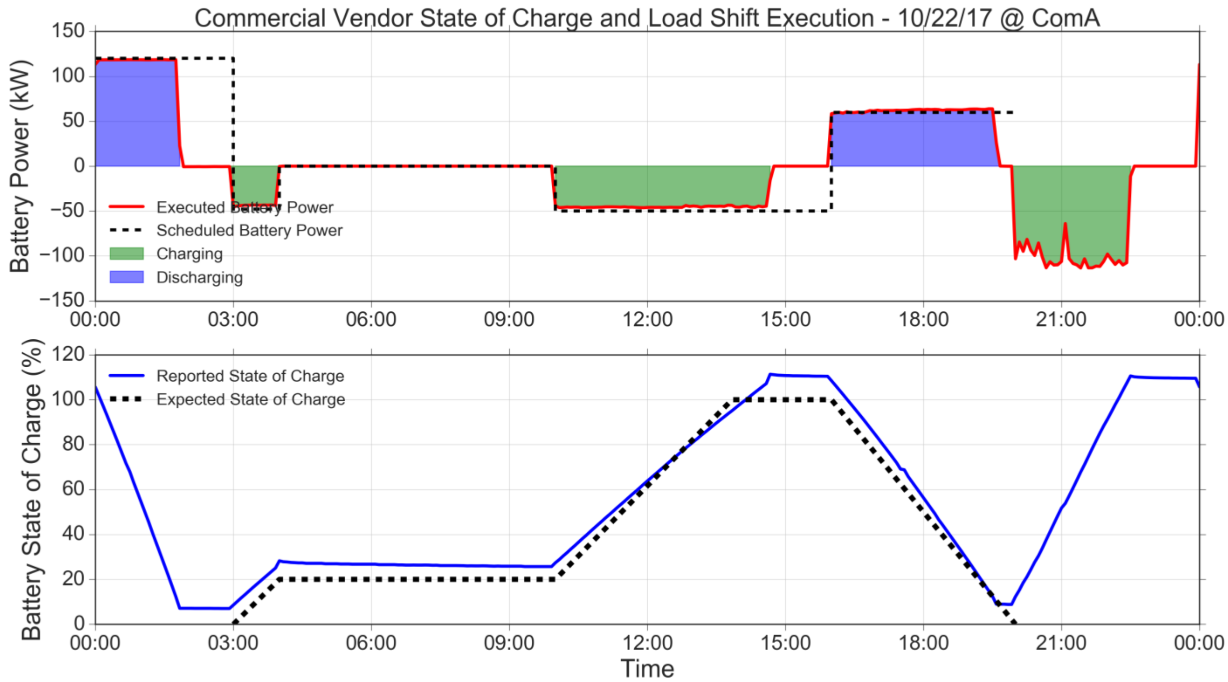

Figure 7: Commercial BTM Battery Power and SoC

4.1.3 Load Shift

Both residential and commercial BTM energy storage vendor systems consistently reduced net load as requested, with a few exceptions. However, residential and commercial BTM energy storage systems fell short of the 4-hour target by 8-to-9 and 15-to-20 minutes, respectively.

Residential Sites

There were a few occasions where battery systems did not perform as expected due to either communication issues (further discussed in Section 4.9.) that prevented the battery from starting/continuing to charge or due to the 0.25-kWh reserve limit that caused the discharge to end before 20:00. For more details, refer to Appendix 1.3.

Commercial Sites

The asset consistently charged at a rate about 5 kW lower than the commanded 50-kW charge at 10:00, as shown in ***Table A.3.5*** in Appendix A.1.3. Also, the discharged rate was about 1 to 2 kW higher than the commanded 60 kW during the discharging period that started at 16:00. The slightly higher discharge rate and efficiency losses caused the discharge duration to be less than commanded – 15 to 20 minutes short of the 4-hour command.

Takeaway – Account for Losses and Reserve

BTM energy storage vendors' battery management systems should account for internal losses and reserve requirements when accepting dispatch command. If internal losses and reserve requirement plus requested energy exceeds the SoC, the command should not be accepted. The vendor should not make a commitment for what cannot be achieved.

4.1.4 Conflicting Request

The flexibility forecast examines the ability of the ESS system to communicate its availability for discharge or charge in forward looking windows of time. In order to examine the accuracy of the flexibility forecast, PG&E scheduled a regular 4-hour full capacity discharge between 16:00 and 20:00 on one residential facility and one commercial facility. This was scheduled through their respective web portals, 2 days in advance. The morning of the scheduled discharge, both assets incorrectly reported discharge flexibility between 14:00 and 16:00. Both residential and commercial ESS were supposed to show no flexibility in the 2 hours before the scheduled discharge because they are required to maintain their SOC to respond to the pre-scheduled discharge.

To explore what would happen if a command were issued based on an inaccurate flexibility forecast, PG&E scheduled a discharge through the DERMS platform between 14:00 and 16:00. There were no previously established requirements in place to address command priority, and hence PG&E had no expectation to how ESS would respond to the DERMS command. The residential BTM energy storage vendor executed the DERMS dispatch and the commercial BTM energy storage vendor executed the previously scheduled dispatch command. Residential and commercial BTM energy storage vendor response to discharge based on (inaccurately) reported flexibility is shown in ***Figure 8*** and ***Figure 9***, respectively.

Residential Sites

Asset was scheduled to be fully charged by 14:00, and then perform a full discharge between 16:00 and 20:00. In the morning, the full flexibility (full SoC) for this asset was reported (forecasted) 2 hours prior to 16:00. This was an inaccurately reported flexibility – the asset should have reported zero flexibility to maintain the full SoC pre-scheduled to be used at 16:00. The DERMS requested discharge of the asset at 14:00 under the false assumption that it has that flexibility in reserve, thus jeopardizing the execution of the previously scheduled discharge at 16:00. In this test, the residential BTM energy storage vendor implemented a rule where the latest command takes priority (overrides previous command), resulting in failure to meet the pre-scheduled command.

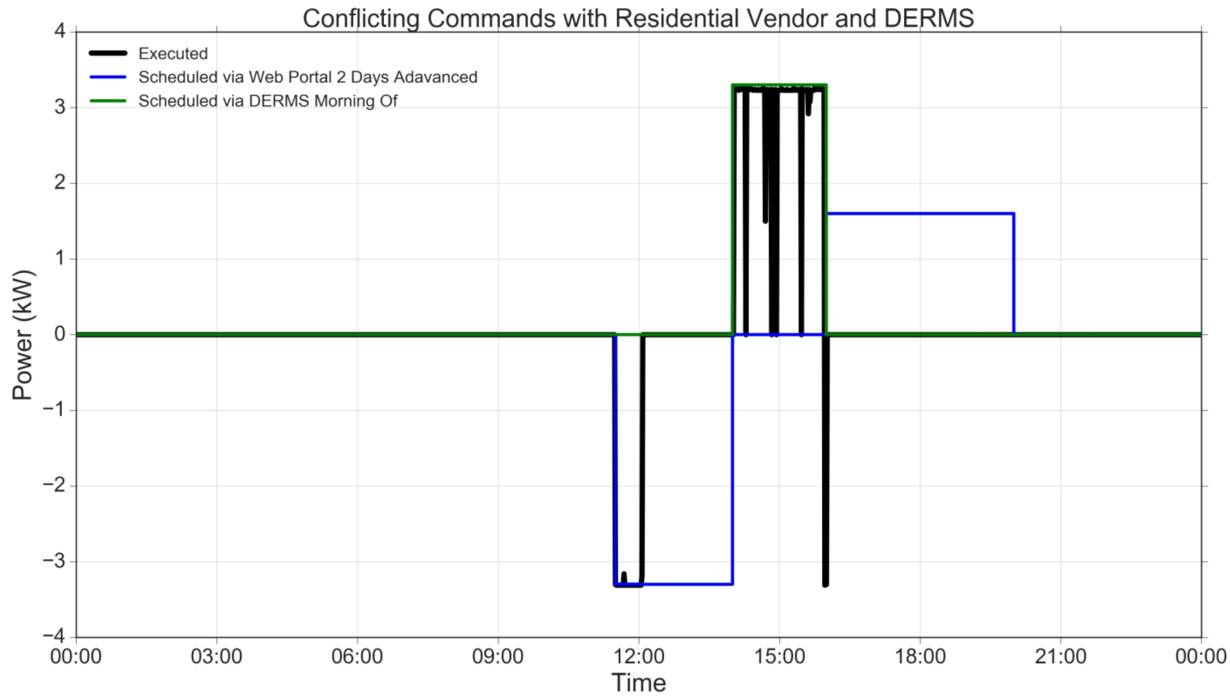

Figure 8: Residential BTM energy storage system response to conflicting request

As shown in ***Figure 8***, the discharge from 14:00 to 16:00 was not constant because it was scheduled as a change in generation. The power output oscillations were due to a real-time control loop action, where the battery is commanded to change the present solar output by the directed amount. From these results, it seems that the control loop was not able to provide a steady power output.

Commercial Site

The asset reported full SoC flexibility between 14:00 and 16:00, which was inaccurate – it should have reported zero flexibility since that full SoC was already scheduled to be used at 16:00. This reported flexibility falsely informed DERMS of available flexibility reserve. As a response test, a full discharge was scheduled between 14:00 and 16:00 via the DERMS aggregator interface. As shown in ***Figure 9***, the asset did not execute the discharge commanded by DERMS, but executed the previously scheduled 16:00 discharge command. The discharge prior to 11:30 and the charging after 20:00 were being executed by the vendors' peak shaving algorithm.

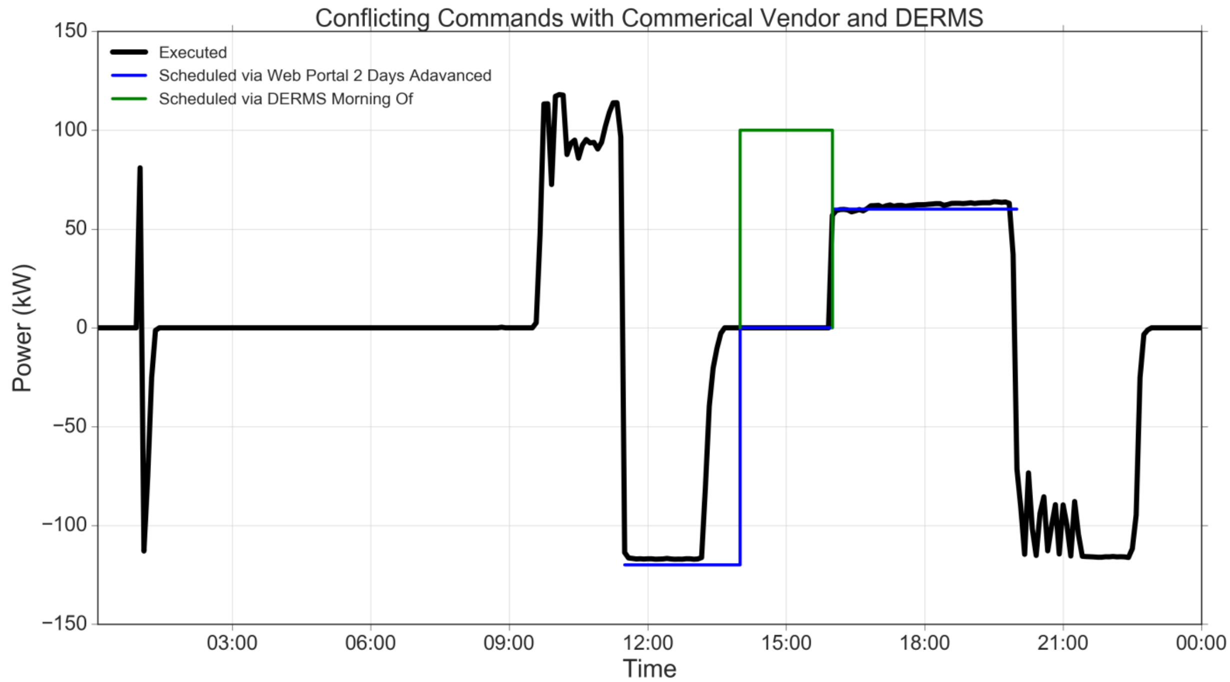

Figure 9: Commercial BTM energy storage system response to conflicting request

Takeaway – Vendors Should Provide Accurate Flexibility Forecast
Flexibility forecast accuracy is an essential functional requirement for market participation, especially in the case of energy storage vendors. Failure to provide an accurate forecast might cause reliability issues and market disruptions.

Takeaway – Customize Command Execution Priority
Utility grid operations applications, such as DERMS, count on energy storage vendors to execute commands based on stated flexibility. Vendor systems should be architected to specify a clear prioritization scheme based on any obligations in place, and flexibility should be reported based on the same prioritization schema. If assets are intended to participate in the distribution system operation environment in a supportive capacity, then the vendor system's control architecture should assign priority to control signals originating from the utility, and flexibility should be reported accordingly. Conversely, if previous commitments take precedence, then the asset should make available only energy volume/time where no previous commitments exist (no conflicts) so that it can respond to commands sent by the utility

4.1.5 Weather vs. Performance

The test results indicate that hot weather had an insignificant impact on performance[17] of the batteries. On hot days, there was no change in performance by residential and 1% poorer performance by commercial site batteries. For more test details, refer to Appendix A.1.4.

[17] This testing does not correspond to total system efficiency – all performance metric, such as the HVAC load that maintains battery temperature, was not accounted for. The HVAC load increases on a hot day, reducing the total efficiency.

4.1.6 Load Profile

Commercial BTM energy storage vendor's peak shaving algorithm (independent of utility control) was effective in flattening the customer load profile. Residential BTM energy storage vendor accomplished load shifting via scheduled discharge. However, the field test results show that residential BTM systems reached low (20%) SoC a short time (8 to 9 minutes) before the end of the requested 4-hour period of energy discharge. The faster discharge is mainly because the command asked for a kW output for a duration of 4 hours and not a kWh delivery in 4 hours. To account for losses, a lower kW value command needed to be set in order to achieve 20% SoC exactly at the end of a 4-hour period of energy discharge.

Residential Sites

There were a total of seven assets used for this test. Initial testing involved only four assets, then 3 more were added to the mix. The setpoints for a group of four assets is shown in ***Table 8***.

Table 8: Commands for Four Aggregated Assets

Start Time	End Time	Real Power Direction	Real Power Setpoint
00:10	05:00	Discharge	13.2 kW
05:00	06:15	Charge	-4 kW
06:15	07:30	Charge	-2 kW
10:00	16:00	Charge	-4 kW
16:00	20:00	Discharge	6.4 kW
20:00	21:00	Charge	-13.2 kW

Gross load was calculated by adding the inverter output (to adjust for sign convention) to the net load obtained from the Smart Meter reads.

$$Gross\ Load = Net\ Load + Inverter\ Power$$

Gross load plus solar production shows what the load profile would have looked like without the battery output, calculated as:

$$Gross\ Load\ plus\ Solar = Net\ Load + Battery\ Power$$

Figure 10 shows the aggregate effect of four battery systems on load profile. It clearly indicates effective load flattening as a result of battery discharge, compared to the gross load plus solar "duck" curve. The negative gross + solar load during the middle of the day indicates backfeed – overall generation greater than load at these sites.

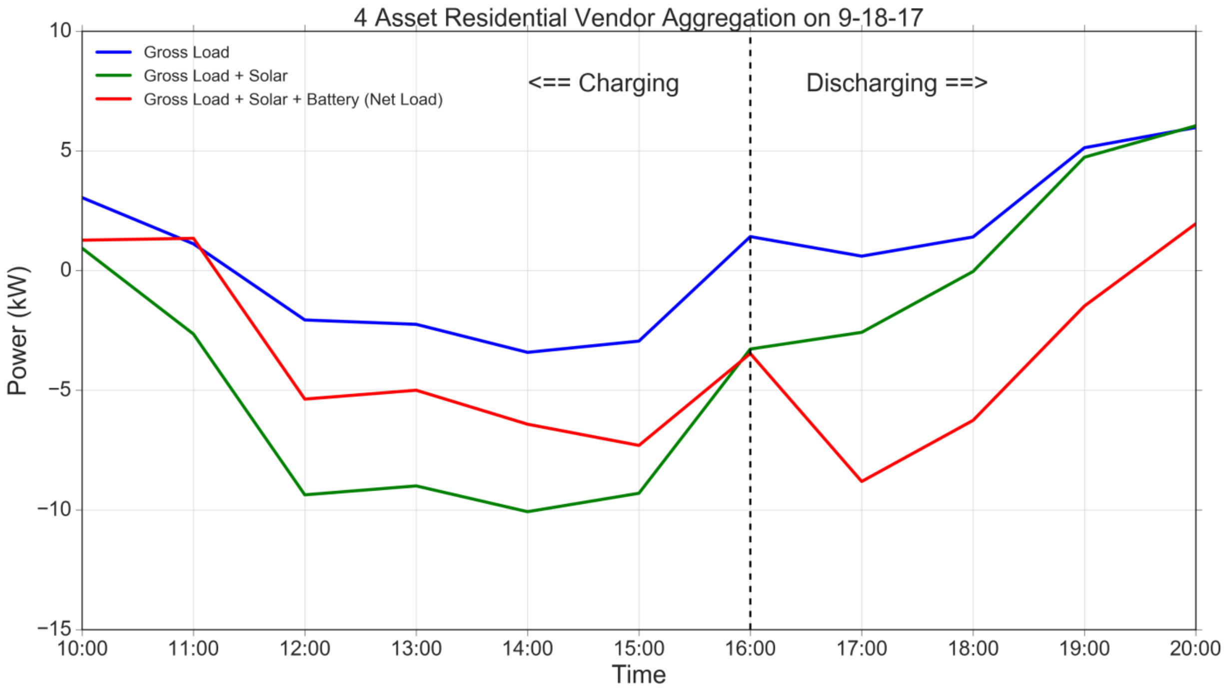

Figure 10: Load Profile for 4 (Aggregated) Residential Asset on Day 3

Another example of modifying the load profile of a residence was demonstrated during the solar eclipse on the August 21. The batteries at 5 sites were scheduled to discharge in order to compensate for the expected loss in solar power because of the eclipse. The expected loss of solar power was estimated using historical data from the systems and the forecasted irradiance during the eclipse. The irradiance forecast was provided by PG&E Meteorology Operations & Analytics group. For more details on calculated solar eclipse generation and battery discharge set points refer to Appendix A.1.5.

Figure 11 shows the results of an attempt to compensate loss of solar generation at one of the sites by discharging residential energy storage at 15-minute interval setpoints based on calculated (forecasted) discharge values. The graph demonstrates that residential energy storage could be used to locally compensate for loss of solar generation, even during such severe intermittency levels as seen on August 21.

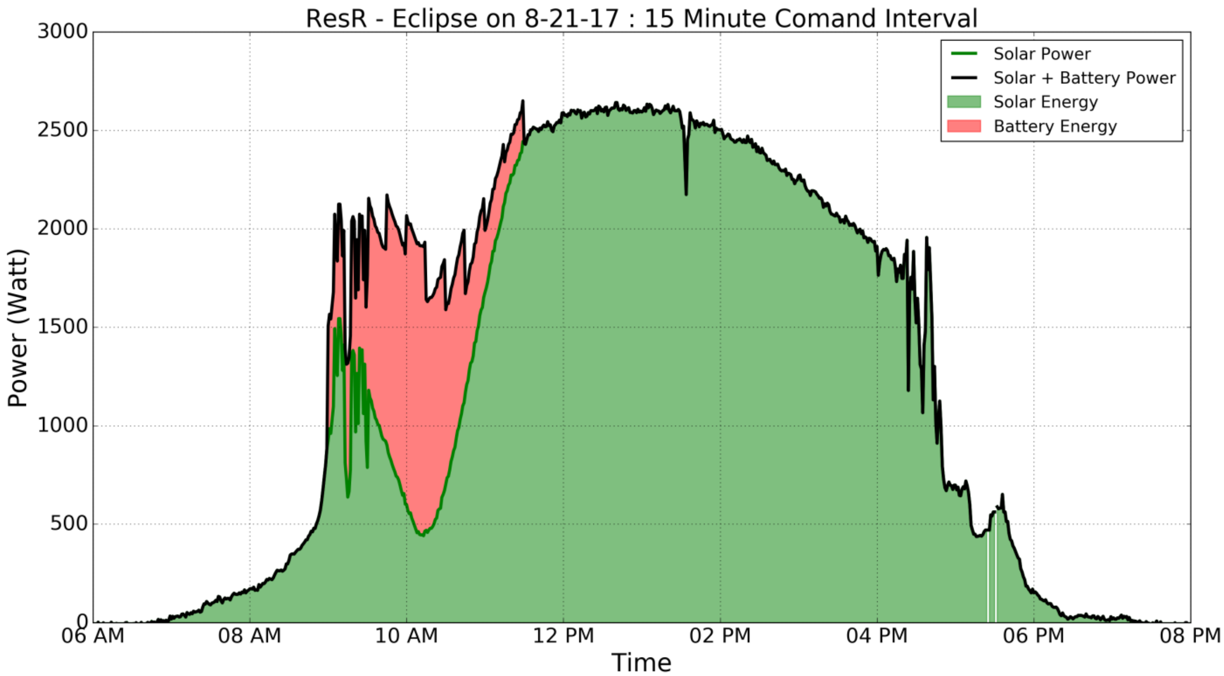

Figure 11: Eclipse Compensation at Residential Asset

Commercial Sites

On all 7 days of this test, the test results showed that the peak shaving algorithm was effective in flattening the net load at this site. ***Figure 12*** shows the gross (actual) and net (load minus battery storage dispatch) load profile. This graph shows that the battery charges at night and early morning, then dispatches in the afternoon when the load peaks at this commercial site. Load profiles for all 7 days of testing can be seen in the Appendix A.1.5.

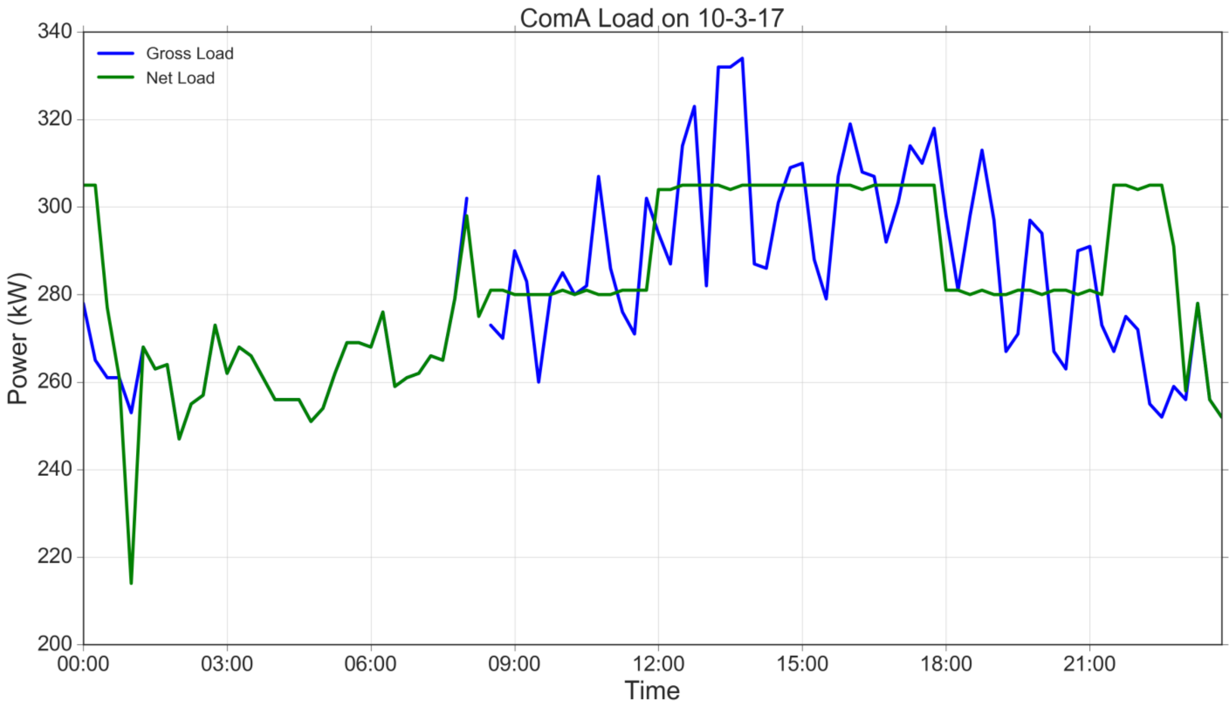

Figure 12: Commercial Site Load Profile on Day 2

Takeaway – Energy Storage Can Help Shape the Net Load Profile
Both residential and commercial energy storage systems could successfully shape the net load profile, including flattening the load profile and compensating for intermittency of solar generation.

4.1.7 Charge from Solar

This test was only applicable to residential sites.

The test results show that the battery systems with attached solar systems could be entirely charged from solar generation over the course of a day. The success rate to fully charge the battery system from solar production depended on the ratio between the solar production (varies throughout the year) and battery size. At single battery system sites, the full SoC success rate was 95-100% and 25-99% during summer and fall season, respectively. At dual battery system sites, the full SoC success rate was 72-100% and 11-100% during summer and fall season, respectively. For more details on these test results refer to Appendix A.1.6. To reach the full battery SoC, proper sizing of both solar and battery systems is required.

Takeaway – Proper System Sizing Required to Store All Solar Energy At the Site
Both solar and battery systems needs to be appropriately sized in order to fully charge the battery only from the PV system.

4.2 Use Case #2: Reliable and Prompt Response

This section summarizes the test results that correspond to Use Case #2: Reliable and Prompt Response, targeting assessment of communication performance of BTM ESS.

4.2.1 Communication Loss

This test evaluated time required to recover the communication process after loss of communications occurred. For residential systems, loss of communication condition corresponded to reset of the home router. For commercial sites, loss of communication corresponded to a loss of cellular signal.

Loss of communication test results for both residential and commercial systems show quite fast system communication recovery of less than 15 min and 17 seconds, respectively.

4.2.2 Communications Reliability

Communication uptime was analyzed by comparing the reported "Online" and "Offline" time periods for every assets in the field. For residential assets in an aggregate, an uptime was greater than 95%, for 75% of days. For commercial assets, uptime was greater than 95%, for 90% of the days.

Residential Sites

Communication uptime graphs are presented ***Figure 13*** and ***Figure 14***. The histogram graph shows that the vast majority of uptime is 99% to 100%. The cumulative distribution function shows the same information in another way - the probability of communication uptime being less than 99% is 35%. However, ***Figure 14*** shows the inconsistencies that occurred in bringing the assets online. Ultimately, most assets were able to reach a reliable uptime steady-state, but there were significant implementation challenges in order to get to this point.

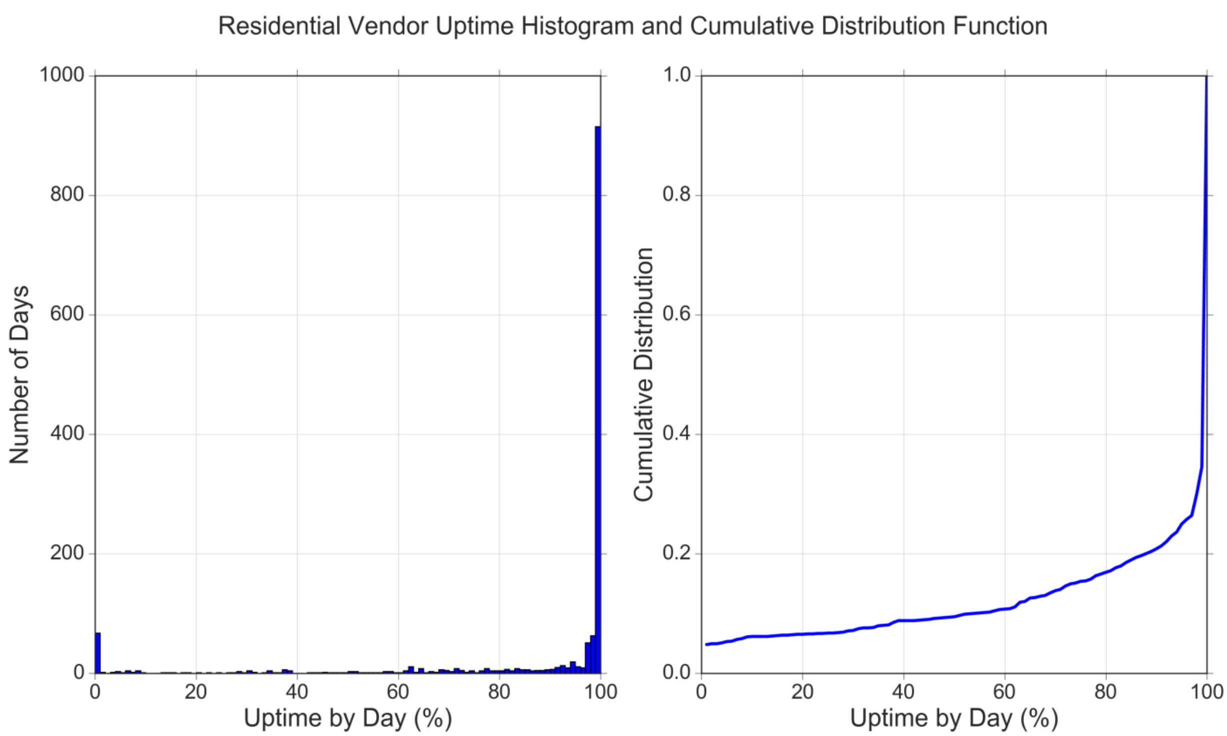

Figure 13: Communication Uptime Histogram and Cumulative Distribution Function

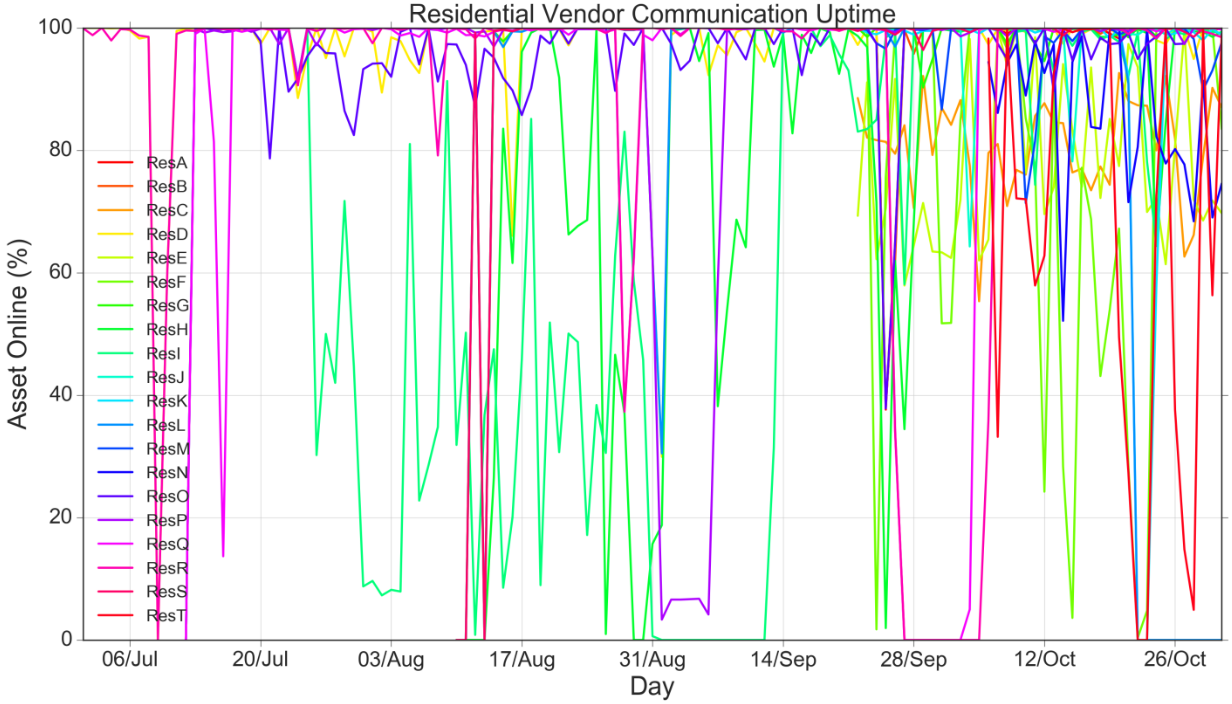

Figure 14: Asset Uptime prior to Project Steady-State

Commercial Sites

Based on reports of whether an asset is online or offline, the percentage of time an asset was reporting online during a day was the communication uptime of that day. ***Table 9*** summarizes the communication uptime analysis results:

Table 9: Commercial Sites Communication Uptime Summary

Asset #	Total Days	Days ≥ 95% Uptime	Days ≥ 99% Uptime	Days ≥ 99.9% Uptime
1	113	102 Days (90%)	67 Days (59%)	41 Days (36%)
2	113	101 Days (89%)	72 Days (64%)	48 Days (42%)

4.2.3 Latency

This test evaluated the time it takes for a command to execute. For both residential and commercial systems, the round trip command latency performance was within SCADA timeout limits.[18]

Residential Sites

This test was conducted on 1 residential asset. A discharge command was sent every 5 minutes from 05:00 to midnight. Data was recorded about every 10 seconds. The latency results are shown in ***Figure*** 15. The min value is the difference between when the command was sent and time of the data recording before the event was observed to be executed. The max value is the difference between when the command was sent and time of the data recording when the event was observed to be executed.

[18] The maximum SCADA response time before a communication error is incurred is 30 seconds.

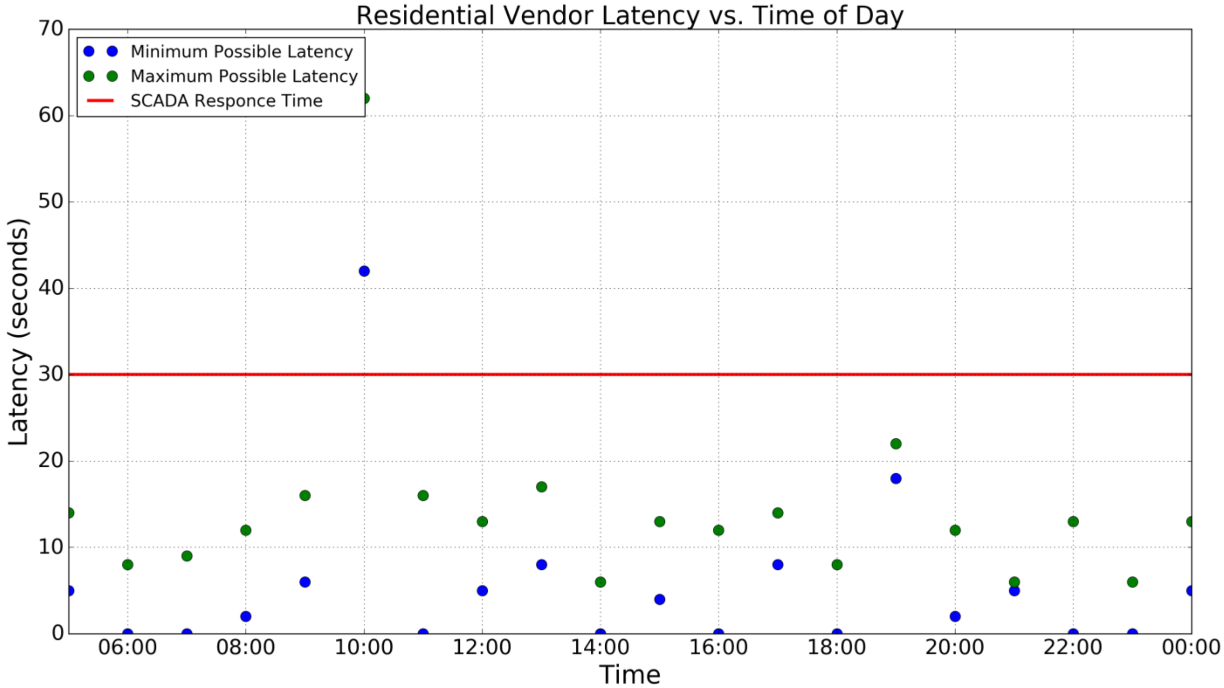

Figure 15: Residential Site Command Latency vs. Time of Day with Real-Time Events

Commercial Site

This test was conducted on 1 commercial asset. A discharge command was sent every 5 minutes from 05:00 to midnight. Data was recorded every second. The time difference when the command was sent and executed is shown in ***Figure 16***. For reference, SCADA requires a response to a poll within 30 seconds.

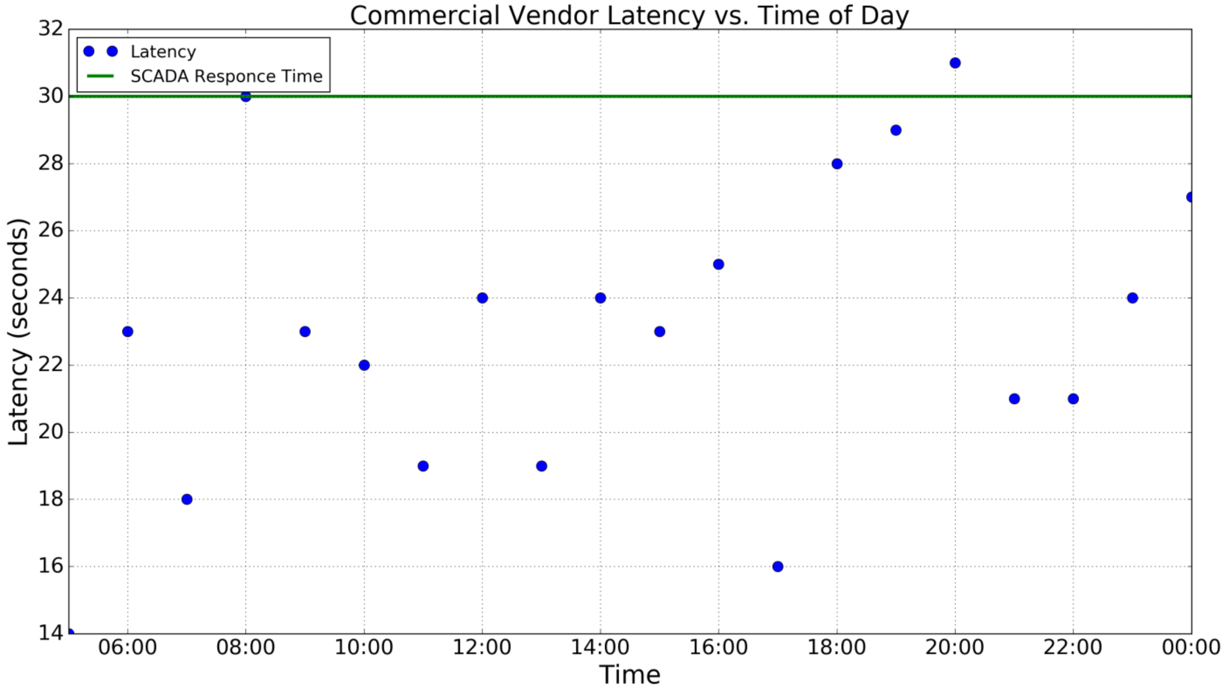

Figure 16: Commercial Site Command Latency vs. Time of Day with Real-Time Events

4.3 Provide Service to Utility and Customer

This section summarizes the test results that correspond to Use Case #3: Provide Service to Utility and Customer, exploring opportunity for ESS to simultaneously perform grid services in addition to reduce customer peak demand charges.

4.3.1 Multiple Functions

This test evaluated the aggregator's ability to execute more than one non-exclusive function at the same time. For commercial BTM energy storage vendor, the first function was to maintain a minimum SoC so the asset can be called upon with short notice for load deferral. The second function was peak reduction function (customer functions). This test applies only to commercial systems, since residential systems were only intended for backup power.

The commercial vendor successfully operated their algorithm for peak shaving and reserved 50% SoC for PG&E's use. The test results showed that charge commands from PG&E can disrupt the economic optimization of the peak shaving algorithm. To reliably follow PG&E's commands, suppression of the commercial vendor's demand charge shaving algorithm was required. The demand charge algorithm was not effective when the constraint of keeping a minimum SoC of 50% was imposed. The commercial vendor explained that this result is anomalous: the vendor limits the amount of charging the system can do to minimize the incurrence of demand charges. They could manually alter the limit but that, in combination with the minimum SoC constraint, led to a state where the peak shaving algorithm would not run. Ultimately this required the test to be run during a new billing cycle so as not to be constrained by prior testing events. ***Figure 17*** demonstrates multiple (peak shaving and 50% reserve) function execution throughout the day.

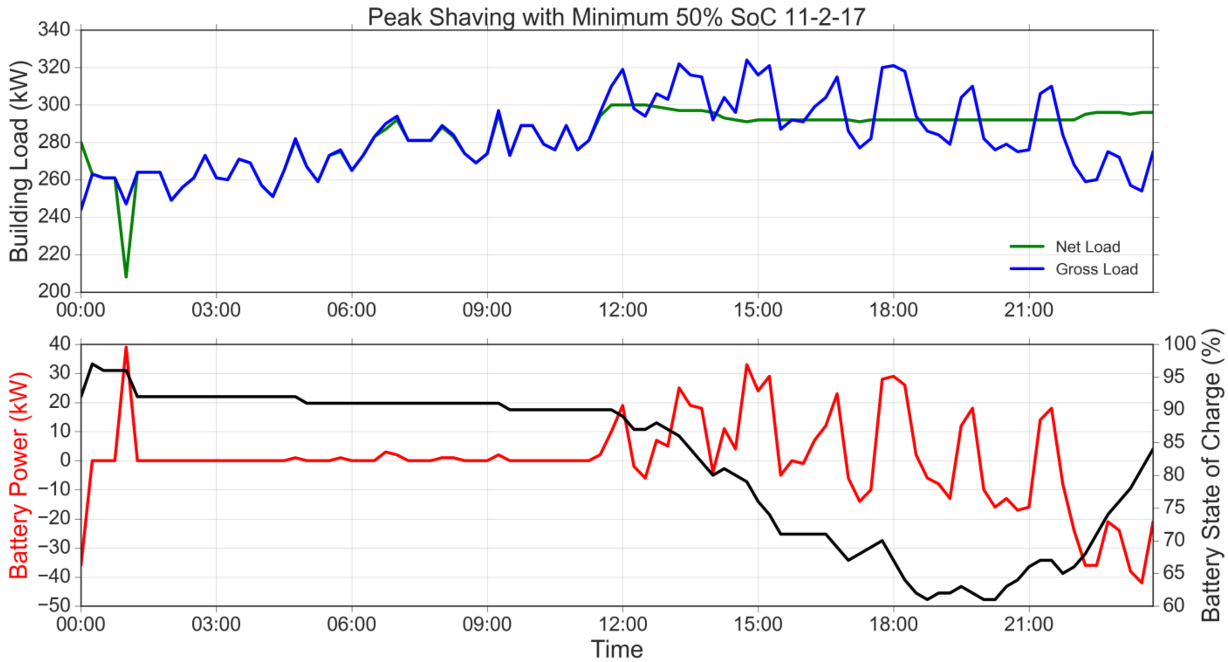

Figure 17: Multiple Functions of Peak Shaving and Reserve Capacity

During the load shit testing, there was an attempt by the commercial vendor to let their algorithm run during utility commands. This could create potentially beneficial results like adjusting power dispatched to match time durations when the SoC was insufficient to meet the time and power requirements of a command. Unfortunately, this resulted in it becoming very difficult to predict how the system would respond to commands. There were many instances of discharge commands ending early to conserve SoC for future uses. It was decided to fully suppress the commercial vendor algorithm while utility commands were scheduled during load shift testing so the length and depth of discharge could be properly characterized.

4.3.2 Dynamic Constraints

This test evaluated the aggregator's ability to perform its normal customer functions with constraints on maximum charge and discharge power, which can be set and changed by the utility. This exploratory test applied only on the commercial BTM vendor systems while performing the ongoing peak-shaving algorithm.

This test involved manually lowering the inverter's maximum power, as it could not be done dynamically. The project team requested this dynamic functionality, but the vendor was unable to supply this functionality within the timeframe of the project. Currently the system can limit the maximum power at the hardware system, but future use cases would require remote control in order to dynamically change the power limit. The project learned that the commercial vendor systems cannot dynamically accept and execute utility imposed constraints. Currently, the inverter output limits can only be manually set.

4.4 Meter Accuracy

This test evaluated the accuracy of the aggregator's metering, which relates to Use Case #4: Meter Accuracy.

Residential System

The inverter, chosen for this project by the residential vendor, was tested at a PG&E lab. The lab results show that the inverter can accurately measure power (within 1% in most cases). ***Table*** 10 summarizes measurement accuracy results. For more measurement test results, refer to Appendix A.1.7.

Table 10: Measurement Error Summary

Measurement	Mean Error	Median Error	Standard Deviation of Error	Range of Error with 95% Probability	Range of Error with 99% Probability
Voltage	0.88 V	0.88 V	0.40 V	0.08 to 1.68 V	-0.16 to 1.92 V
Reactive Power	110 volt-ampere reactive (VAR)	121 VAR	217 VAR	-324 to 544 VAR	-454 to 674 VAR
Real Power	37.6 W	36.9 W	17.9 W	1.8 to 73.4 W	-8.9 to 84.1 W

Commercial System

At one of the sites, a PG&E Power Quality Meter was installed at the battery system's AC disconnect to evaluate the accuracy of the vendor metering. The results showed that the inverters provide real power measurements that are accurate (within 2.6% not correcting for ancillary loads) on average. The spread on accuracy was large which resulted in a possible error range of 20% with a 99% probability. The cause of the large spread in error is not known but it is suspected that the aggregation and averaging across 4 inverters over 5 minutes is the culprit. It is recommended that commercial battery systems have a single meter with all inverters and ancillary loads behind it. For more details, refer to Appendix A.7.

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 & Electric Company (SDG&E), and Southern California Edison Company (SCE). Project 2.19c – *Customer-Sited and Community Behind-the-Meter Storage* has demonstrated the use of customer-sited energy storage technologies to reduce peak loading and absorb solar generation. Such capability qualifies the BTM ESS as one of the solutions to manage the net load profile in California.

The project also showed that a number of improvements – ranging from customer acquisition to reliable communications to dispatch prioritization algorithms - need to take place in order to fully leverage the BTM ESS technology at scale.

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: This project explored the use of customer-sited behind-the-meter storage to respond to instructions to charge during times of maximum solar output and discharge during the later afternoon net load ramp when solar output is declining, an application of the technology which could contribute to grid reliability. In addition, the project investigated the dual-use of customer-owned storage to provide back-up power for individual customers.
- Lower costs: This project explored the use of customer-sited BTM energy storage to provide commercial customers with opportunities to lower their cost of energy via peak load shaving to avoid demand charges, while also executing directions to charge during times of maximum solar output and discharge during the later afternoon net load ramp when solar output is declining.
- Increased safety and/or enhanced environmental sustainability: In addition to testing the ability of customer-sited storage systems to absorb system solar power, this project also explored the use of residential storage co-located with solar PV systems to charge the batteries exclusively using solar power. Both applications of customer-sited energy storage can help better integrate renewables.

5.2 Secondary Principles

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

- GHG emissions reduction: Flexible resources can enable reliable operation of the grid with fewer fossil plants required to remain online at minimum load to meet evening ramps. Reducing the number of start-ups and minimum load hours of fossil generation helps to reduce GHG emissions from the residual fossil fleet. This project helped PG&E better understand how these flexible resources could be used in the future programs. Perhaps more importantly, this project showed PG&E what types of considerations the utility should make for program development.
- Efficient use of ratepayer funds: The CPUC has mandated that 15MW of customer-sited BTM storage be deployed by 2017 (Decision 13-10-040). California Assembly Bill 2514 mandates that PG&E procure 80MW of customer-sited storage by 2020. The Self Generation Incentive Program offers ($0.46/W-$1.83/W) incentive to customers wishing to deploy storage. As such, California has dedicated substantial funding towards procuring storage. This project helps enable more efficient use of the funds allocated by demonstrating how BTM storage can be used by the utility to integrate renewable energy.

6 Accomplishments and Recommendations

The project accomplished the objective to demonstrate the use of customer-sited energy storage technologies to reduce peak loading and absorb DER generation. The project also experienced challenges, which combined with the test results, provided learnings that helped PG&E craft a set of recommendations for future opportunities to leverage BTM ESS.

6.1 Key Milestones

The following summarize key milestones:

- Deployed 240 kW, 2 hours of customer-sited BTM commercial storage and 64.8 kW, 2 hours of residential storage.
- Commissioned 20 residential and 2 commercial sites with BTM energy storage systems.
- Executed 13 field tests, testing BTM energy storage systems control, communications, and measurement accuracy performances.
- Demonstrated the ability of aggregated, customer-sited BTM energy storage systems to reduce peak loading or absorb distributed generation on a utility distribution feeder(s).
- Qualified/quantified BTM energy system command execution, meter accuracy, communication reliability and latency, and system uptime performance.
- Demonstrated the ability of BTM energy storage solutions to simultaneously provide service to utility and customer, if designed to do so.

6.2 Key Learnings, Takeaways and Recommendations

Release RFO for commercial and residential battery storage vendors

- **Learning – Clear Guidelines and Requirements Benefit the RFO Process**
  Clear guidelines and requirements in the RFO (essentially a Scope of Work) helped to streamline contract negotiation post vendor selection. In PG&E's case, the bulk of the contract negotiation was related to Legal Terms and Conditions rather than SOW content.

Customer Acquisition

- **Learning – Identify and Account For Customer Acquisition Risks**
  Vendors struggled to acquire customers due to a combination of issues: limited access to customer information, customer fatigue from door-to-door solar, unclear equipment retrofit outcome, and shifting customer engagement strategies, to name a few. The project learned that customer acquisition risks should be more heavily weighted to establish more realistic timelines and projected outcomes for BTM NWA projects, which are very sensitive to time, quantity and location of the resource's deployment.

- **Next Step – Right Customer Acquisition Targets for Right Vendors in Right Areas**
  Challenges in achieving customer acquisition targets for each vendor may have been due to a variety of circumstances, such as customers with existing solar system having restriction on testing rights, the customer engagement strategy, and customer fatigue from door-to-door solar sales. One project learning is that customer acquisition risks should be identified and accounted for upfront to establish more realistic timelines, particularly when targeted deployment of DERs is required for safe operation of the grid (e.g. as part of a non-wires alternative capacity project).

Next Step - PG&E May Want or Need to Take Greater Role in Customer Acquisition
Although PG&E facilitated the development of co-branded marketing collateral to ensure consistent messaging and help drive efficiencies between the vendors, the vendors utilized their own platforms and resources to develop the actual materials. PG&E's role was to vet, approve, and signoff on all materials prior to the vendor releasing them to the public. There was good collaboration between the parties and assurance that the materials met PG&E's approved marketing guidelines. For future projects that involve customer acquisition, future teams should consider working with PG&E to evaluate past marketing efforts, to vet customer acquisition strategy, and to determine whether PG&E should take on specific tasks or lead customer acquisition efforts.

Permitting and Interconnection

- **Learning – Understand Regulatory and Engineering Requirements to Bring Assets Online**
  For DERs, it is crucial to understand the regulatory and engineering requirements to bring assets online. Vendors and PG&E have both streamlined activities for solar interconnection process. However, neither the vendor nor PG&E anticipated the length of time required for solar plus storage interconnection. PG&E is currently working with storage vendors today to streamline its interconnection process.

- **Learning – Account for City and Local Jurisdiction Permitting Requirement Complexities**
  Cities and AHJ's often have their own sets of requirements. To properly set expectations, the project plan needs to account for these complexities. While both the City of San Jose and the residential vendor had permitted storage before, it is not standardized. As a result, the process required multiple rounds of inspections and additional engineering details that were not required for solar-only interconnection permitting.

Asset Commissioning & Site Acceptance Testing

- **Learning – More Testing 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 of this project. This suggests that vendor systems needed more testing by vendors before being handed over to PG&E for the site acceptance testing. This would reduce start-up and ramp- up times.

Technical Results

- **Takeaway – Requirements Should Be Timely Coordinated Internally and Provided to Vendors**
  Technical requirements should be internally coordinated and provided to the vendors in a timely manner, especially when multiple projects are co-located and leverage the same assets. With individual project requirements in place, vendors may be time constrained to make adjustments per all requests in a short time.

- **Takeaway – More Cooperation Among Energy Storage and Equipment Vendors Needed**
  The inverter manufacturers' control algorithms should be more transparent to energy storage vendors, and energy storage vendors should be more familiar with inverter control algorithms. Information exchange among vendors will help maintain reliable operation of systems, especially when firmware changes take place.

- **Takeaway – Account for Losses and Reserve**
  BTM energy storage vendors' management systems should account for internal losses and reserve requirements when accepting dispatch command. If internal losses and reserve requirement plus requested energy exceeds the SoC, the command should not be accepted. The vendor should not make a commitment for what cannot be achieved.

- **Takeaway – Vendors Should Provide Accurate Flexibility Forecast**
  Flexibility forecast accuracy is an essential functional requirement for market participation, especially in the case of energy storage vendors. Failure to provide an accurate forecast might cause reliability issues and market disruptions.

- **Takeaway – Customize Command Execution Priority**
  Utility grid operations applications, such as DERMS, count on energy storage vendors to execute commands based on stated flexibility. Vendor systems should be architected to specify a clear prioritization scheme based on any obligations in place, and flexibility should be reported based on the same prioritization schema. If assets are intended to participate in the distribution system operation environment in a supportive capacity, then the vendor system's control architecture should assign priority to control signals originating from the utility, and flexibility should be reported accordingly. Conversely, if previous commitments take precedence, then the asset should bid only energy volume/time where no previous commitments exist (no conflicts) so that it can respond to commands sent by the utility.

- **Takeaway – Energy Storage Can Help Shape the Net Load Profile**
  Both residential and commercial energy storage systems could successfully shape the net load profile, including flattening the load profile and compensating for intermittency of solar generation.

- **Takeaway – Proper System Sizing Required to Store All Solar Energy At the Site**
  Both solar and battery systems need to be appropriately sized in order to fully charge the battery only from the PV system.

- **Next Step – Faster Response Time Needed For Frequency Regulation Response**
  A latency requirement that was not explored in this technology demonstration but would be good to consider and demonstrate is for frequency regulation, which requires a 4-second response time since instructions are deployed on a 4 second basis.

6.3 Recommendations

Based on the experience gained through the Behind-the-Meter demonstration, PG&E continues to support the deployment of BTM DER technologies to provide distribution capacity. The project identified several key barriers that should be addressed prior to expanding the use of BTM storage as a grid resource including gaps in asset data accuracy and visibility, and scalability of the utility-aggregator communications system. A set of recommendations follows to enable BTM storage 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, DRP, and IDER. This project's learnings about BTM technology capabilities to provide grid services on utility request will inform the next steps in the DRP and IDER proceedings and workshops, including Distribution Infrastructure Deferral Framework, Competitive Solicitation Framework, Grid Modernization, and Rule 21 Interconnection workshops and filings.

While there were challenges in customer acquisition, asset deployment, asset communications, flexibility forecasting, and dispatch algorithm development, the demonstration and test field results showed that aggregated BTM storage resources have the potential to be utilized by the utility to reduce electric load or to absorb distributed generation on a utility distribution feeder. These issues will need to be addressed before advancing this functionality beyond the technology demonstration stage. Our recommendations are summarized below, which support the project's initial four Key Objectives:

A. Evaluate the technical ability of BTM energy storage to **reduce peak loading** or absorb distributed generation on utility distribution feeder(s), with sufficient reliability for distribution grid operations
B. Clarify storage **technology and process requirements** to integrate and interoperate DERs to address grid needs, and characterize barriers to deployment at scale relative to today.
C. **Demonstrate and evaluate communications** available to provide DER visibility, monitoring, and control in order to address grid needs reliably today.
D. Evaluate the ability of BTM energy storage to **simultaneously provide services** to a utility and the on-site customer, correctly prioritizing distribution services.

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

Implementation of Behind the Meter storage systems to support grid reliability is not yet at a "plug-and-play" state. (Key Objectives A, B). *The project experienced challenges related to customer acquisition, permitting and interconnection complexities. (**Section 3.4, Section 3.7)** Challenges in achieving customer acquisition targets for each vendor may have been due to a variety of circumstances, such as customers with existing solar system having restriction on testing rights, the customer engagement strategy, and customer fatigue from door-to-door solar sales. One project learning is that customer acquisition risks should be identified and accounted for upfront to establish more realistic deployment timelines, particularly when targeted deployment of DERs is required for safe operation of the grid (e.g. as part of a non-wires alternative capacity project). Furthermore, the process for interconnecting solar with storage is also more complex and more variable than the process for solar-only installations from a permitting and engineering requirements standpoint. There are additional engineering and tariff complexities for interconnecting solar and storage which are not present in solar interconnections. At the time of the project's asset deployment, PG&E and one of the vendors had already each processed hundreds of thousands of solar interconnections, and a few hundred solar with storage. Nevertheless, neither the vendor nor PG&E anticipated the length of time required for the project's solar plus storage interconnections which ranged from 8 to 27 weeks. The process for permitting the storage systems with local authorities likewise created additional complexities and delays. Anticipating these challenges and timeline impacts to bring assets online in the future is paramount.*

Targeting the right customers for acquisition in right areas (Key Objectives A, B)*–Addressing local reliability needs on the distribution grid using BTM energy storage or other DERs in a identified area should be based on the an assessment of the sufficiency of customers that could participate which can provide the necessary capabilities.*

There still exists an open question as to how widespread customers' demand/receptivity is to this technology (Key Objectives A, B)*, their willingness and extent to which they will participate in programs that can produce realizable grid reliability benefits. The residential vendor gave away a "free" battery and the commercial vendor had financial incentives in place but that was not sufficient to draw significant interest from the original targeted amount of customers. A question arises of whether the host utility taking an active role in customer acquisition versus a "vendor-led" approach, as was taken in this technical demonstration, could have affected customer acquisition for the project. For future technology demonstrations that may involve customer sited asset deployment, it would be beneficial to evaluate whether the customer acquisition process would be more successful if the utility takes the lead or a stronger role on customer acquisition rather than the vendor.*

Addressing distribution constraints requires sufficient scale and response time on the feeder to mitigate potential issues (Key Objectives A and B)*. Targeted customer acquisition in a short timeframe was challenging, resulting in a 66% shortfall of resources relative to the project's objective. In the context of addressing an actual distribution constraint (which did not exist on this feeder), such a significant shortfall relative to expectations could result in failure to resolve the constraint.* ***(Section 3.7)*** *This issue needs to be better understood in order to pursue scalability.*

- Vendors should set conservative expectations for acquiring customers and plan for long asset deployment timelines.

- Regulators should recognize and leverage the value of the utility brand in acquiring customers for new programs.
- Regulators should not rely on targeted DER deployment as a quick or easy solution to provide distribution services where they are needed.
- Regulators should standardize permitting for solar plus storage installations across Authorities Having Jurisdiction (AHJ)
- Utilities should adopt internal processes and expectations regarding DER deployment for distribution services.
- Utilities should find alternatives to customer acquisition pursuing demonstrations with the ability to retrofit equipment.

Vendor Software

Importance of prioritization of distribution grid reliability services for Multiple Use Application DERs. (Key Objectives B and D)*. The demonstration identified instances where distribution dispatch signals were not prioritized relative to other uses. For BTM resources to fully provide grid reliability value through distribution dispatch, clear and consistent prioritization would be required.* ***(Section 4.3)*** *Grid needs can range from regularly shifting load to help manage the duck curve at the CAISO system level to dispatching in response to a utility distribution operator command to mitigate local voltage or capacity issues. Ability of BTM storage to serve both customer and grid needs is a key advantage; however, this project sheds light on the complexity of achieving the reliable dispatch of such systems. Some challenges are commercial in nature, such as the inability to dispatch the large percentage of BTM resources that are subject to lease agreements which prohibit curtailment, resources that are being used to minimize customer bills (e.g. demand charge management) or resources that are sold as "backup power supplies." Other challenges are technical, such as the challenge of consistently maintaining communication with resources without an expensive dedicated pathway. In many cases, challenges arise from the lack of mature systems and vendors. These range from many control algorithm glitches uncovered during functional testing to basic misunderstandings about how to measure key operating metrics like state of charge and available capacity.*

The two aggregators participating in this technology demonstration have their own software platforms for scheduling dispatch instructions to their respective assets. The commercial storage aggregator also operates an algorithm to optimize customer bill savings from the storage asset. Through this technology demonstration, PG&E gained valuable experience using the aggregators' platforms and observing the interplay between the commercial aggregator's algorithm and our dispatch instructions. Based on that experience, we recommend the following improvements to energy storage vendor software to support smoother operation of such assets in the future.

- Vendors should integrate and validate real-time asset performance into their platforms.
- Vendors should implement a prioritization for energy storage assets performing multiple uses where the distribution signals are paramount (i.e. which dispatch instruction will take priority when there are conflicting requests for distribution services and customer bill reduction)
- Regulators should recognize that vendor platforms are not off-the-shelf products, and will require modifications to fit specific program needs.

- Utilities should investigate alternatives to a vendor-operated platform for managing BTM resources.

Utility Software

BTM storage technology possesses the technical capabilities to reduce peak load and absorb generation*, in response to grid instructions. However,* ***further action and investment is required to demonstrate capability for scaled deployment*** *of the technology as an effective and reliable grid resource in the future (Key Objective A).*

Lessons learned inform steps that need to be taken to successfully scale the project and to ***operationalize and integrate BTM energy storage*** *to reliably meet the needs of the grid.* ***To achieve the key objectives in a wider scale production environment, additional software and hardware investments are necessary relative to what was included in the technical demonstration*** *(Key Objectives A, B, C, D). Specific enhancements that would enable grid planners and operators to fully realize the value of BTM energy storage to meet grid reliability needs include:* ***Increasing the direct and granular visibility into the operational status of distributed energy resources (e.g., state of charge, etc.) to facilitate successful distribution operations in a high DER penetration future.*** *This demonstration highlighted several DER operational metrics that must be monitored reliably for DER distribution services to be scaled: e.g., state of charge, asset availability, metrology accuracy, and timeliness, consistency and accuracy of real-time response. Enhancements in the accuracy of real-time communications, increased uptime of operating assets, and greater clarity and adoption of a standard definition of asset availability would enable the full realization of the expected DER value. By providing grid operators with visibility into the operational data from the aggregator or the facilities, and ensuring the dependability/reliability of the resource for planners, BTM energy storage can become an effective grid resource.*

An integrated grid platform, which does not exist today, would be needed to enable 1) real-time communication of distribution dispatch instructions to the aggregators/storage units, and 2) automated optimization of grid operations leveraging both traditional distribution operations equipment and BTM energy storage. (Key Objectives B and C) *Given the dynamic operating conditions of each feeder and the localized distribution grid, the frequent rerouting of power over different distribution feeders to minimize the duration and magnitude of local outages, and the need for work clearances to ensure the safety of the public and utility crews, operational capabilities that can automatically analyze grid conditions, determine optimized solutions, and communicate signals to aggregators/assets would greatly enhance the value of DERs to the grid operator and planner. In this demonstration, the project team communicated a pre-established test plan directly to the aggregators platforms. To leverage distributed storage as a more widely deployed resource across the distribution grid on a real-time basis, grid operations and control systems will need to have the capabilities of an integrated grid platform that would provide instructions to localized DERS and optimize the tools available to grid operators to effectively, efficiently and safely manage real-time operating conditions. Additional equipment and protocols beyond those employed in this technical demonstration will be necessary to mitigate inaccurate or inconsistent reporting to avoid under-delivery of battery discharging, or inconsistent assessments of the BTM energy storage resources' state of charge and energy availability, which can diminish the value of the BTM energy storage resource to the grid.*

While this project demonstrated that that aggregated customer-sited BTM energy storage can be used for distribution services, a necessary component to scale the usage of BTM energy storage will be a system to coordinate these resources. PG&E will need to invest in an integrating platform to manage the widespread usage of BTM energy storage and other DERs for distribution services such as peak shaving. Specific areas of focus include:

- New capabilities and applications such as Advanced Distribution Management System (ADMS) and Distributed Energy Resource Management System (DERMS)
- Foundational model/system improvements to enable these applications
- Monitoring and communications to provide necessary visibility on grid conditions

Reliable communication links and response time protocols are critical for success. (Key Objectives A, B, C and D)*. The project utilized hard-wired residential internet to communicate with the residential assets and cell connections for the commercial assets. Residential internet is a generally low-cost solution but has significant drawbacks and may not be suitable for utility-scale programs.* ***(Section 4.2)***

- ***Reliable communications with DER assets*** *– The combination of communication protocols (e.g., Zigbee and customer internet) caused problems. Residential internet is low cost, but would not meet utility-scale robustness and reliability. For assets to participate in grid services at scale, more reliable and standardized communication performance should be adopted.*
- ***Frequency regulation requires faster response time*** *– For both vendors, the response times were under 30 seconds, which was satisfactory for the purposes of this project. However, faster response times may be needed for certain California Independent System Operator CAISO ancillary services. While CAISO ancillary services were not in scope of this project, more robust communication would be required to enable this technology.*

Communications

Communication between the storage aggregator and individual storage assets was an ongoing challenge in this technology demonstration. In some cases, dispatch signals were not followed because a communications outage prevented the storage asset from receiving it. The ability of both aggregators to reliably drop load as instructed was compromised due to frequent loss of communications link with the storage assets. Before pursuing wider-scale deployment of this technology demonstration, we recommend the following steps to improve communications reliability.

- Regulatory standards should specify uniform metrics for communication between utilities and BTM energy storage systems.
- Utilities and regulatory standards should specify minimum latency and communication uptime for BTM energy storage systems participating in a utility program.
- Vendors should pursue alternative communications methods, to customers' home router or cellular signals, in situations where home router or cellular signals cannot meet utilities' reliability requirements.
- Utilities should require minimum latency and communication uptime for BTM energy storage systems participating in a utility program.
- Vendors and utilities together should explore hard-wired DER communications pathways.

6.4 Technology transfer plan

6.4.1 IOU's technology transfer plans

A primary benefit of the EPIC program is the technology and knowledge sharing that occurs both internally within PG&E, and across the other IOUs, the CEC and the industry. To facilitate this knowledge sharing, PG&E will share the results of this project in industry workshops and through public reports published on the PG&E website. Specifically, below are information sharing forums where the results and lessons learned from this EPIC project were presented or plan to be presented:

Information Sharing Forums Held

- *CEC Fall EPIC Symposium*
  Sacramento, CA | February 5, 2018

6.4.2 Adaptability to other Utilities and Industry

Keeping in mind the specific hardware and software used in this project, the learnings from this project can be applied to any other utility that targets use of emerging customer-sited BTM technologies. Overall, the demonstrated capabilities benefit the entire electric power industry and can be applied to any geographical location in the country.

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 Metrics

The following metrics (***Table 11***) were identified for this project and included in PG&E's EPIC Annual Report as potential metrics to measure project benefits at full scale.[19] Given the proof of concept nature of this EPIC project, these metrics are forward looking.

[19] 2015 PG&E EPIC Annual Report, February 29, 2016. http://www.pge.com/includes/docs/pdfs/about/environment/epic/EPICAnnualReportAttachmentA.pdf.

Table 11. Project Metrics

D.13-11-025, Attachment 4. List of Proposed Metrics and Potential Areas of Measurement (as applicable to a specific project or investment area)	Reference
1. Potential energy and cost savings	
i. Nameplate capacity (MW) of grid-connected energy storage	3.3.1
3. Economic benefits	
b. Maintain / Reduce capital costs	4.6
f. Improvements in system operation efficiencies stemming from increased utility dispatchability of customer demand side management	4.3
5. Safety, Power Quality, and Reliability (Equipment, Electricity System)	
b. Electric system power flow congestion reduction	4.3
7. Identification of barriers or issues resolved that prevented widespread deployment of technology or strategy	
a. Description of the issues, project(s), and the results or outcomes	3.7
b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (Public Utilities Code (Pub. Util. Code) § 8360)	4.3, 4.6
d. Deployment and integration of cost-effective distributed resources and generation, including renewable resources (Pub. Util. Code § 8360)	3.3.1

9 Conclusion

The project demonstrated both the possibility that BTM energy storage can support grid reliability, as well as the additional work needed to enable scalability, widespread use of BTM energy storage for grid support, and full realization of its value as a grid resource. While there were challenges in customer acquisition, asset deployment, asset communications, flexibility forecasting, and dispatch algorithm development, the demonstration and test field results showed that aggregated BTM storage resources have the potential to be utilized by the utility to reduce electric load or to absorb distributed generation on a utility distribution feeder. With additional investments that enable grid operations that support better utility monitoring, visibility, and control capabilities, BTM energy storage technology has the potential to become a net load management tool that can play a significant role in shaping California's energy future. For BTM energy storage assets to be reliably used for distribution or grid services, the utility will need to have additional hardware and software systems (e.g., two-way, communication systems, DERMS, prioritization protocols, etc.) to provide visibility into accurate asset performance and availability, and assurances that the BTM energy storage assets will consistently and reliably respond to dispatch signals in a timely manner This demonstration project identified several key areas where a more scalable solution could support the use of BTM storage as a grid resource if some of the implementation and communication challenges are overcome.

Because of this project, distribution planning engineers and program managers can better understand BTM energy storage technology capabilities, reliability, and maturity. This suggests that BTM energy storage can be considered as a potential resource to address grid capacity constraints and support integration of cost-effective distributed resources and generation, including renewable resources.

In addition, this project provided insights into communication performance: discovering communication uptime as a concern for implementation at scale. When assets were online, they met most use case requirements, with latency that is within Supervisory Control and Data Acquisition (SCADA) timeout limits, but not frequency regulation requirements. If uptime communications requirements are met, implementation challenges are overcome, and asset availability is accurately reported, BTM energy storage technology may be able to provide grid services. To leverage BTM energy storage in system operations, flexibility forecast accuracy and communications uptime must be improved. Further, absent an integrated platform, implementation at scale is limited.

The project identified several key barriers that should be addressed prior to expanding the use of BTM storage as a grid resource including gaps in asset data accuracy and visibility, and scalability of the utility-aggregator communications system. A set of recommendations follows to enable BTM storage to be effectively and reliably used as a grid resource in the future.

The project served as an informative and enabling precursor to the fulfillment of California State Assembly Bill (AB) 2514[20] and AB 2868,[21] which require local, investor-owned electric utilities (IOU) to procure energy storage systems. In addition, this project aimed to support the California Public Utilities Commission (CPUC) proceeding, Distribution Resources Plan (DRP) R.14-08-013,[22] evaluating aggregated behind-the-meter (BTM) customer energy storage as a non-wire alternative (NWA) to address capacity constraints identified using the Distribution Investment Deferral Framework (DIDF) in the utilities distribution planning process. For that reason, PG&E is investigating customer-sited BTM energy storage technology readiness and improvement opportunities. This project provided valuable learnings related to use of customer-sited BTM energy storage technology in support of advancing the integration of DERs into PG&E's distribution planning, grid operations and investment processes.

EPIC Project 2.19c created a BTM energy storage technology demonstration as a foundation upon which electric utilities, regulators, adjacent industries, policy makers, and prospective vendors can build 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.

[20] AB 2514 was designed to encourage California to procure by 2020 and incorporate by 2024 energy storage into the electricity grid in order to support the integration of greater amounts of renewable energy into the electric grid, defer the need for new fossil-fueled power plants and transmission and distribution infrastructure, and reduce dependence on fossil fuel generation to meet peak loads. http://www.energy.ca.gov/assessments/ab2514_energy_storage.html.

[21] The California Public Utilities Commission (CPUC) has issued an order requiring that PG&E, SCE, and SDG&E propose programs and investments for up to 500 megawatts (MW) of distributed energy storage systems, distributed equally among the three utilities, above and beyond the 1,325 MW target for energy storage already required pursuant to AB 2514. http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M184/K630/184630306.PDF.

[22] Distribution Resources Plan ((Rulemaking (R.) 14-08-013).

10 Test Results

10.1 Inverter kVA Limit

Given active and reactive setpoints are shown in ***Table A.1.1***., and corresponding field measurements are shown in ***Figures A.1.1*** through ***A.1.3.***

Table A.1.1: Commercial BTM System Real and Reactive Power Setpoints for Test #1

Real Power Direction	Real Power Setpoint (kW)	Reactive Power Direction	Reactive Power Setpoint (kVAR)	Duration (hours)
Discharge	120	---	0	1
Charge	-120	---	0	1
---	0	Import	-120	1
---	0	Export	120	1
Discharge	84	Import	-84	1
Charge	-84	Import	-84	1
Discharge	84	Export	84	1
Charge	-84	Export	84	1

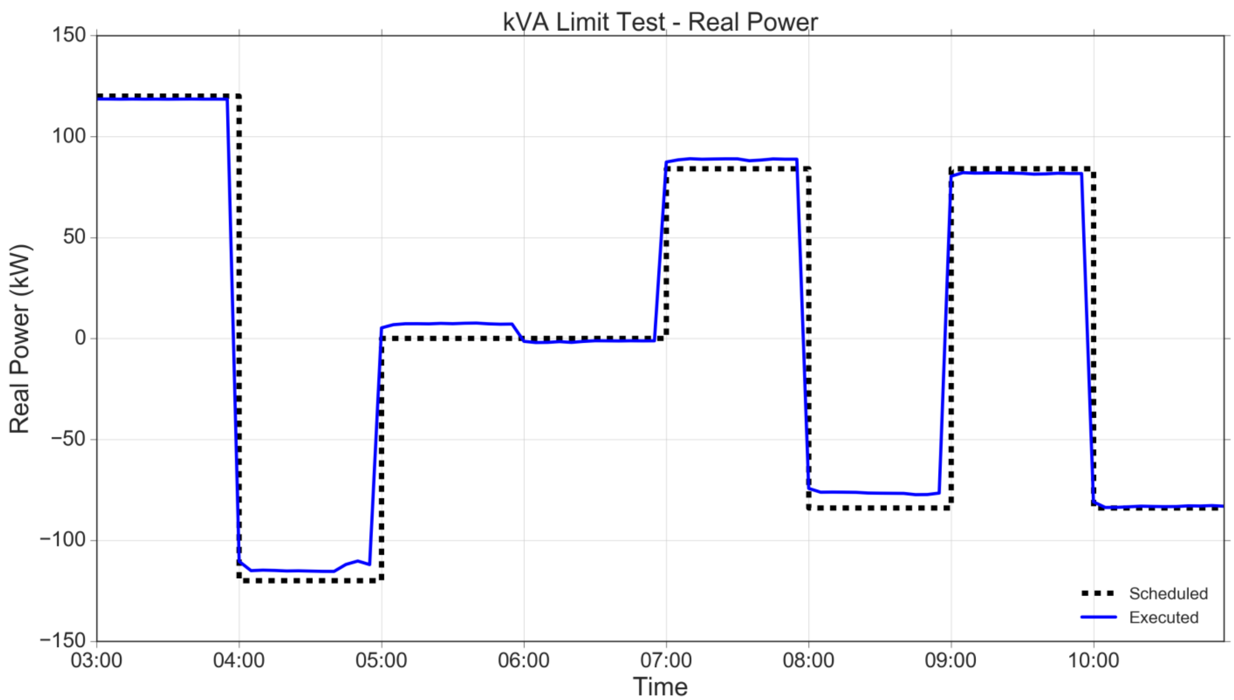

Figure A.1.1: Real Power during kVA Limit Test at Commercial BTM Site

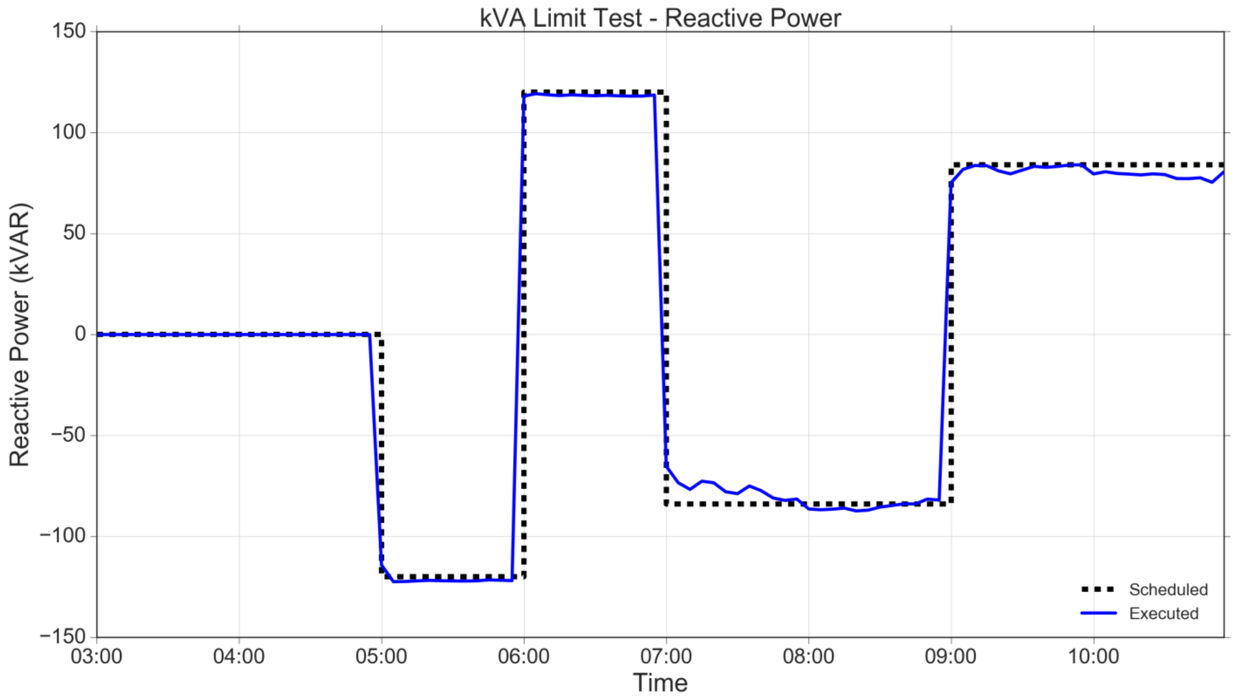

Figure A.1.2: Reactive Power during kVA Limit Test at Commercial BTM Site

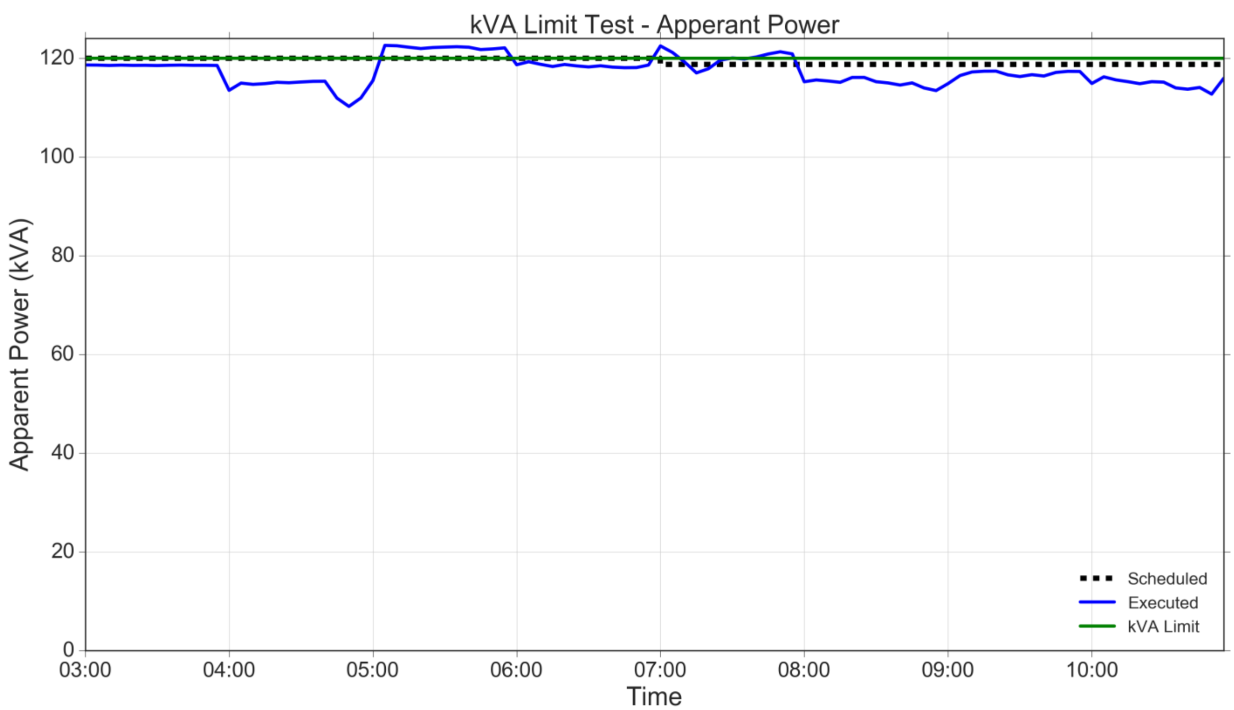

Figure A.1.3: Apparent Power during kVA Limit Test at Commercial BTM Site

10.2 State of Charge

Residential Sites – SoC Test Results

The SoC states at 10:00 for 14 consecutive days is shown in ***Table A.2.1***. All but one site maintained the SoC between 20% and 25%, which is reasonably close to the 20% SoC target – met expectations. Test points outside of the 20-25% SoC range are highlighted in red.

Table A.2.1: Residential Sites SoC at 10:00

Asset						
A	**B**	**C**	**D**	**E**	**F**	**G**
23.8%	23.9%	Offline	23.9%	24.8%	24.1%	24.2%
22.2%	22.2%	23.3%	22.7%	24.2%	38.4%	21.3%
22.5%	21.7%	Offline	22.3%	24.5%	22.7%	22.2%
22.2%	22.3%	22.0%	21.7%	24.4%	22.0%	21.7%
22.2%	22.5%	23.4%	21.7%	24.1%	4.1%	21.7%
21.9%	23.4%	21.6%	23.6%	24.2%	5.5%	23.3%
22.3%	21.6%	22.5%	21.6%	24.1%	3.8%	21.6%
23.1%	21.6%	21.6%	21.9%	24.2%	22.0%	21.7%
22.5%	21.6%	21.7%	21.9%	24.1%	22.0%	23.6%
21.4%	21.7%	21.7%	21.9%	24.2%	4.1%	21.6%
22.2%	21.3%	21.3%	21.4%	23.3%	21.3%	22.0%
21.6%	21.7%	21.9%	22.0%	24.2%	5.6%	24.1%
21.6%	23.4%	21.9%	22.0%	24.1%	3.8%	21.6%
21.6%	21.7%	21.9%	21.9%	24.1%	3.9%	21.6%

Asset C was out of communication at 10:00 on 2 of the 14 of the test days. Asset E failed to deliver the 20% SoC at 10:00 on 8 of the 14 test days - on 7 days the asset fell far short of the SoC target and on one day it overcharged to 38% - due to communication problems that caused the asset to not execute the 05:00 charge command. Such problems could be caused if something (e.g., a car is in the garage) disrupted the wireless communication between the inverter and the gateway in the morning hours.

The SoC states at 16:00 for 14 consecutive days is shown in ***Table A.2.2***. All but one site maintained the SoC at 100%. Assets C and G experienced loss of communication at 16:00 on the first day of testing – SoC unknown. The communication issues with asset F caused the 100% SoC target to be missed on 7 days. Also, asset G only reached a 61% SoC on one of the days because the charge command ended early. This is discussed further in Section 4.3 (Load Shift) in the body of the report.

Table A.2.2 – Residential Sites SoC at 16:00

Asset						
A	**B**	**C**	**D**	**E**	**F**	**G**
100.0%	100.0%	Offline	100.0%	100.0%	100.0%	Offline
100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
100.0%	100.0%	100.0%	100.0%	100.0%	92.5%	100.0%
100.0%	100.0%	100.0%	100.0%	100.0%	93.8%	100.0%
100.0%	100.0%	100.0%	100.0%	100.0%	91.9%	100.0%
100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
100.0%	100.0%	100.0%	100.0%	100.0%	92.5%	100.0%
100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	60.8%
100.0%	100.0%	100.0%	100.0%	100.0%	94.4%	100.0%
100.0%	100.0%	100.0%	100.0%	100.0%	92.3%	100.0%
100.0%	100.0%	100.0%	100.0%	100.0%	92.3%	100.0%

Commercial Site – SoC Test

On one of the days during the commissioning period, from about 14:00 to 17:00, the tested asset reported that SoC plateaued, even though the reported battery power was not 0. As a point of comparison, the reported battery power was integrated to calculate the SoC. The 255 kWh was selected as the constant of integration, so the calculated SoC lines up with the reported SoC after the full discharge command is executed. The vendor explained that the battery management system was calibrating its SoC during that plateau at about 160 kWh.

As shown in ***Figure A.2.1***, there was an additional calibration point that can be seen just before 12:00 at about 110 kWh. The calibration plateau was supposed to be short like the one just before 12:00, but in this case the calibration lasted until the battery was discharged back to about 160 kWh. The exact cause of this stayed unknown. Because this misreported SoCs phenomenon did not persist, a further analysis and solution was not pursued in this project.

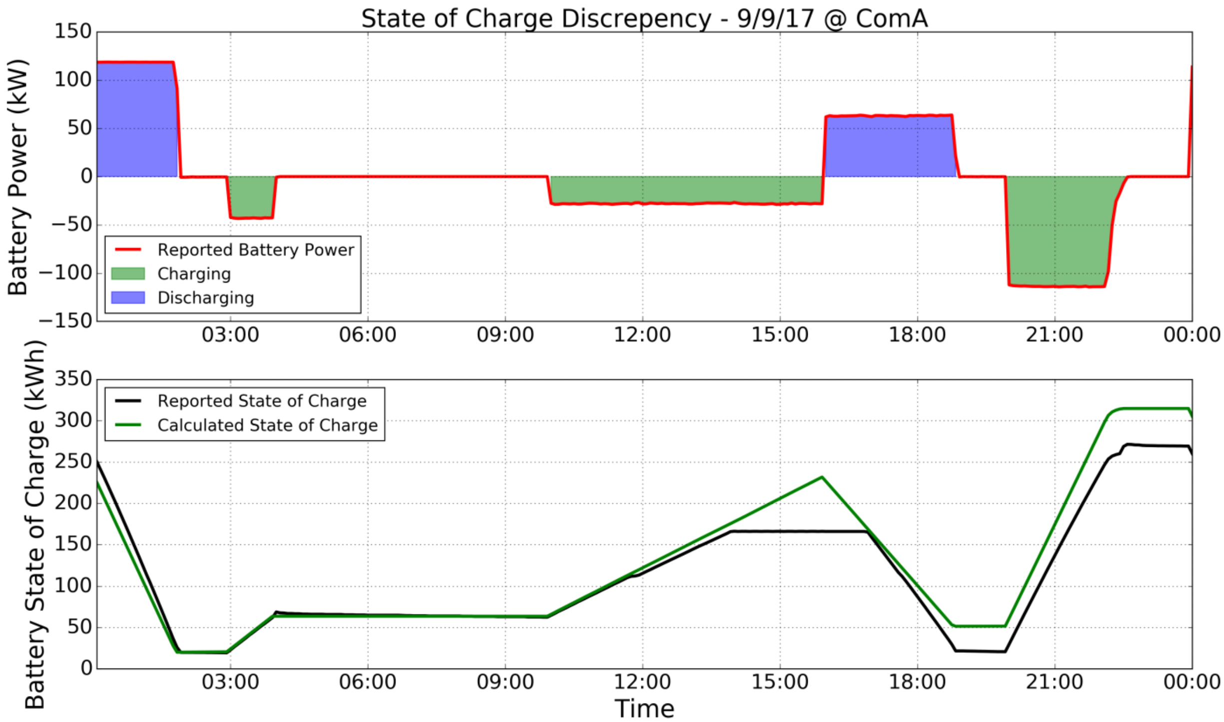

Figure A.2.1 – SoC Discrepancy at Commercial BTM Site

10.3 Load Shift

Residential Sites

Table A.3.1 shows times when the asset stopped executing the 10:00 charge command. The charge command was for 6 kWh. However, charging was expected to end before 16:00, because the battery was expected to have about 5 kWh available for charging at 10:00. Overall, the residential vendor assets performed well, with the following exceptions:

- The entire days schedule did not execute at asset C on day 1 (highlighted yellow in ***Table A.3.1***).
- Charging ended about an hour before expected at F on day 2 (highlighted red in ***Table A.3.1***), due to poor communication (further discussed in Section 4.2). This happened because the SoC was 38% at 10:00 rather than the expected 20% - 25%.
- 30 minutes after commanded, charging stopped at asset G on day 11 (highlighted green in ***Table A.3.1***). This happened when an asset lost communication in the middle of a battery (charge/discharge) event, stopping sometimes the execution of the event. Communication was lost at asset at 10:32 on 10-22-17.

Table A.3.1: Residential BTM Systems Midday Charge End Time – Expected before 16:00

Day	Asset						
	A	B	C	D	E	F	G
1	15:06	15:03	Offline	15:05	15:08	15:07	15:12
2	15:10	15:08	15:05	15:09	15:11	14:09	15:21
3	15:09	15:10	15:11	15:10	15:07	15:11	15:18
4	15:10	15:08	15:10	15:13	15:10	15:13	15:20
5	15:10	15:07	15:07	15:12	15:10	15:56	15:19
6	15:10	15:04	15:12	15:06	15:10	15:53	15:13
7	15:09	15:11	15:09	15:13	15:10	15:51	15:19
8	15:06	15:11	15:13	15:12	15:10	15:13	15:19
9	15:09	15:11	15:13	15:12	15:10	15:12	15:12
10	15:12	15:10	15:12	15:12	15:09	15:59	15:19
11	15:10	15:11	15:14	15:15	15:10	15:16	10:32
12	15:12	15:10	15:12	15:12	15:09	15:26	15:10
13	15:12	15:04	15:12	15:11	15:09	15:59	15:17
14	15:12	15:10	15:12	15:12	15:09	15:50	15:17

Table A.3.2. shows the average power during the 10:00 to 16:00 charge interval. All measured values were as expected (1000 W). In all cases, 1kW +/- 10 watts charge command was issued.

Table A.3.2: Midday Charge Power – Expected 1000W

Day	Asset						
	A	B	C	D	E	F	G
1	-993 W	-995 W	Offline	-1005 W	-995 W	-1004 W	-995 W
2	-993 W	-995 W	-1002 W	-1005 W	-995 W	-1004 W	-995 W
3	-993 W	-995 W	-1002 W	-1005 W	-995 W	-1004 W	-995 W
4	-993 W	-995 W	-1002 W	-1005 W	-995 W	-1004 W	-995 W
5	-993 W	-995 W	-1002 W	-1005 W	-995 W	-1005 W	-995 W
6	-993 W	-995 W	-1002 W	-1005 W	-995 W	-1005 W	-995 W
7	-992 W	-995 W	-1002 W	-1005 W	-995 W	-1005 W	-995 W
8	-993 W	-995 W	-1002 W	-1005 W	-995 W	-1004 W	-995 W
9	-993 W	-995 W	-1002 W	-1005 W	-995 W	-1004 W	-995 W
10	-993 W	-995 W	-1002 W	-1005 W	-995 W	-1005 W	-995 W
11	-993 W	-995 W	-1001 W	-1005 W	-994 W	-1004 W	-995 W
12	-993 W	-995 W	-1002 W	-1005 W	-995 W	-1005 W	-995 W
13	-993 W	-995 W	-1002 W	-1005 W	-995 W	-1005 W	-995 W
14	-993 W	-995 W	-1002 W	-1005 W	-995 W	-1005 W	-995 W

Table A.3.3 shows times when the 16:00 discharge command stopped. It was found that residential energy storage systems would not discharge the rated capacity because they always held a minimum of 0.25 kWh in reserve. Given this reserve, the discharge is expected to end before 20:00. In most cases the discharge lasted between 3.8 and 3.9 hours, with a few exceptions:

- The discharge fell short at asset F because of the morning communication issues discussed in Section 4.2. (highlighted red in ***Table A.3.3***)
- Communication was lost at 17:31 at asset A on day 5, causing the asset to stop its discharge command. (highlighted green in ***Table A.3.3***)
- The loss of communication during charging caused the discharge to be short at asset G on day 11. (highlighted purple in ***Table A.3.3***)
- Communication was lost at asset G on day 9 for the rest of the day at 18:43. No knowledge if the asset continued to discharge after that. (highlighted brown in ***Table A.3.3***)
- Communication was lost at asset G on day 1 for the rest of the day at 15:25. It is not known if the discharge executed. (highlighted yellow in ***Table A.3.3***)

Table A.3.3: Residential BTM Battery Evening Discharge End Time

Day	Asset						
	A	B	C	D	E	F	G
1	19:53	19:52	Offline	19:53	19:52	19:54	Offline
2	19:53	19:53	19:54	19:53	19:52	19:54	19:56
3	19:53	19:52	19:54	19:53	19:52	19:53	19:56
4	19:53	19:52	19:53	19:53	19:52	19:53	19:56
5	17:31	19:52	19:53	19:53	19:52	19:37	19:56
6	19:52	19:51	19:53	19:52	19:51	19:39	19:55
7	19:52	19:51	19:52	19:52	19:51	19:36	19:55
8	19:52	19:51	19:52	19:52	19:51	19:53	19:55
9	19:52	19:51	19:52	19:52	19:51	19:52	18:43
10	19:52	19:51	19:52	19:52	19:51	19:37	19:55
11	19:51	19:49	19:50	19:52	19:49	19:52	18:20
12	19:52	19:51	19:51	19:52	19:51	19:41	19:55
13	19:52	19:51	19:51	19:52	19:51	19:36	19:55
14	19:52	19:51	19:51	19:52	19:52	19:36	19:55

Table A.3.3 shows the average power during the 16:00 to 20:00 discharge. The discharge ended as expected, before 20:00. In all cases when the asset was online, the discharge was 1.55 kW +/- 15 W. ***Table A.3.4*** shows average discharge power between 16:00 and 20:00. Results were as expected (around 1600 W).

Table A.3.4: Residential BTM Battery Evening Discharge Power

Date	Asset SPID						
	8102122805	8674934105	8675056105	8696324505	8091807305	8143727905	8570965610
10/4/2017	1547 W	1547 W	Offline	1566 W	1543 W	1556 W	Offline
10/5/2017	1546 W	1548 W	1560 W	1566 W	1543 W	1556 W	1556 W
10/8/2017	1546 W	1548 W	1560 W	1566 W	1546 W	1556 W	1556 W
10/9/2017	1546 W	1548 W	1560 W	1566 W	1541 W	1556 W	1556 W
10/10/2017	1546 W	1548 W	1560 W	1566 W	1541 W	1556 W	1556 W
10/12/2017	1546 W	1547 W	1560 W	1566 W	1543 W	1556 W	1556 W
10/13/2017	1546 W	1547 W	1560 W	1566 W	1543 W	1556 W	1556 W
10/14/2017	1546 W	1547 W	1560 W	1566 W	1542 W	1556 W	1556 W
10/15/2017	1546 W	1548 W	1561 W	1566 W	1543 W	1556 W	1557 W
10/16/2017	1546 W	1548 W	1560 W	1566 W	1541 W	1556 W	1556 W
10/22/2017	1546 W	1547 W	1560 W	1566 W	1546 W	1556 W	1556 W
10/23/2017	1546 W	1548 W	1560 W	1566 W	1542 W	1556 W	1556 W
10/25/2017	1547 W	1548 W	1560 W	1566 W	1541 W	1556 W	1556 W
10/26/2017	1547 W	1548 W	1561 W	1566 W	1541 W	1556 W	1556 W

Commercial Sites

Table A.3.5 shows the average power during the charging period that started at 10:00. The charged rate was about 5 kW lower than the commanded 50 kW.

Table A.3.5: Commercial BTM Battery Midday Charge End Time and Power

Day	Charge End Time	Expected Charge End Time	Average Charge Power	Commanded Charge Power	% Deviation from Command
1	14:45	16:00	-45.1 kW	-50.0 kW	-9.8%
2	14:50	16:00	-45.0 kW	-50.0 kW	-10.0%
3	14:45	16:00	-45.7 kW	-50.0 kW	-8.6%
4	14:45	16:00	-45.2 kW	-50.0 kW	-9.6%
5	14:45	16:00	-45.5 kW	-50.0 kW	-9.0%
6	14:45	16:00	-45.4 kW	-50.0 kW	-9.2%
7	14:45	16:00	-45.4 kW	-50.0 kW	-9.2%
8	14:45	16:00	-45.6 kW	-50.0 kW	-8.8%
9	14:45	16:00	-45.3 kW	-50.0 kW	-9.4%
10	14:45	16:00	-45.4 kW	-50.0 kW	-9.2%
11	14:50	16:00	-45.0 kW	-50.0 kW	-10.0%
12	14:50	16:00	-44.9 kW	-50.0 kW	-10.2%
13	14:55	16:00	-44.2 kW	-50.0 kW	-11.6%
14	14:50	16:00	-44.9 kW	-50.0 kW	-10.2%

Table A.3.6 shows the average power during the discharging period that started at 16:00. The discharged rate was about 1 to 2 kW higher than the commanded 60 kW. The duration of discharge was 15 to 20 minutes short of the 4-hour command. The slightly higher discharge rate and efficiency losses caused the discharge duration to be less than commanded.

Table A.3.6: Commercial BTM Battery Evening Charge End Time and Power

Date	Discharge End Time	Expected Discharge End Time	End Time Deviation (min)	Average Discharge Power	Commanded Discharge Power	% Deviation from Command
1	19:40	20:00	20	62.1 kW	60.0 kW	3.3%
2	19:40	20:00	20	61.9 kW	60.0 kW	1.7%
3	19:45	20:00	15	61.0 kW	60.0 kW	1.7%
4	19:40	20:00	20	61.7 kW	60.0 kW	1.7%
5	19:45	20:00	15	61.3 kW	60.0 kW	1.7%
6	19:45	20:00	15	61.2 kW	60.0 kW	1.7%
7	19:40	20:00	20	62.0 kW	60.0 kW	3.3%
8	19:40	20:00	20	62.2 kW	60.0 kW	3.3%
9	19:40	20:00	20	62.1 kW	60.0 kW	3.3%
10	19:40	20:00	20	62.4 kW	60.0 kW	3.3%
11	19:40	20:00	20	62.0 kW	60.0 kW	3.3%
12	19:40	20:00	20	62.1 kW	60.0 kW	3.3%
13	19:45	20:00	15	61.4 kW	60.0 kW	1.7%
14	19:40	20:00	20	62.7 kW	60.0 kW	3.3%

10.4 Weather vs. Performance

Residential Sites

This test consisted of 2 full charge-discharge cycles. Performance was evaluated based on the battery's DC power. This was done because getting the hot day data would require testing when the sun was up. The additional solar power on the inverter could impact the results, because the additional power should change the inverter's efficiency. Performance was evaluated based on the following equation:

$$Prformance = \left| \frac{\sum_{Start\ Time}^{End\ Time} DC\ Power\ (kW) > 0}{\sum_{Start\ Time}^{End\ Time} DC\ Power\ (kW) < 0} \right|$$

If the numerator is divided by 60, it is equivalent to the amount of energy discharged in the time interval; it is necessary to divide by 60 because power was reported every minute.

The asset was fully discharged before the test began the 2 cycles were done again at between 00:00 and 08:00 where the ambient temperature ranged between 60°F and 63°F. The measurements can be seen in ***Figure A.4.1***.

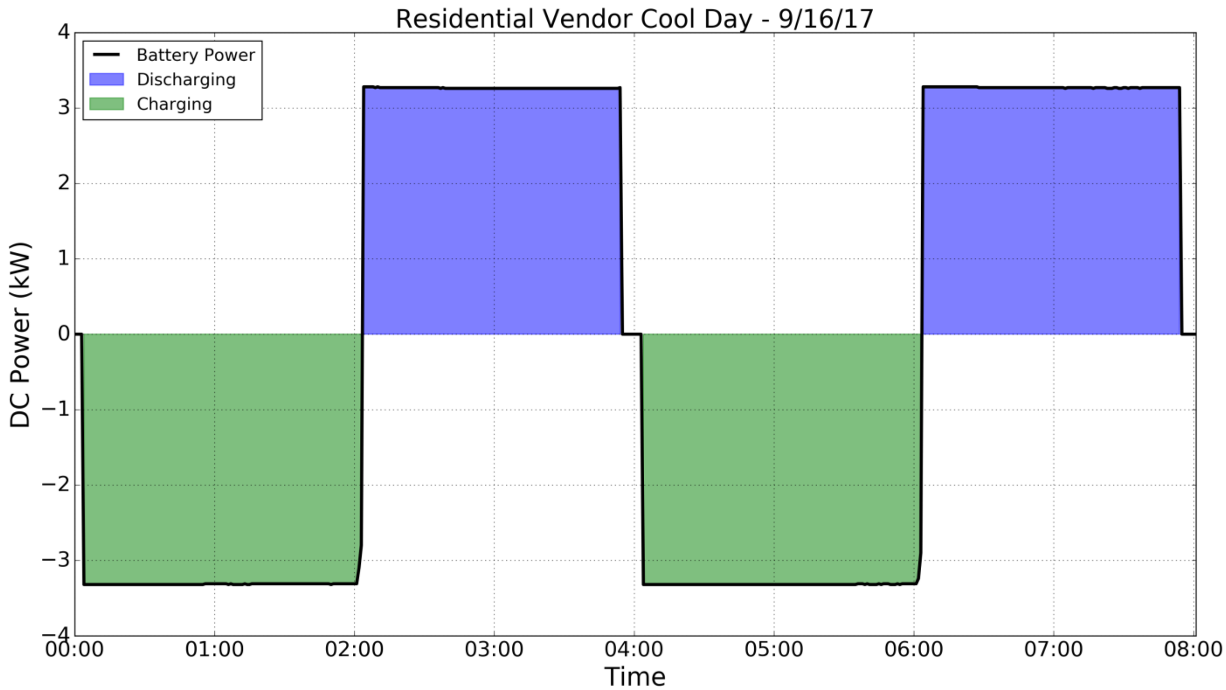

Figure A.4.1: Residential Site Cool Day Performance

The 2 full cycles were done on between 11:00 and 19:00 on a day when the ambient temperature ranged between 95°F and 108°F. The measurements can be seen ***Figure A.4.2***.

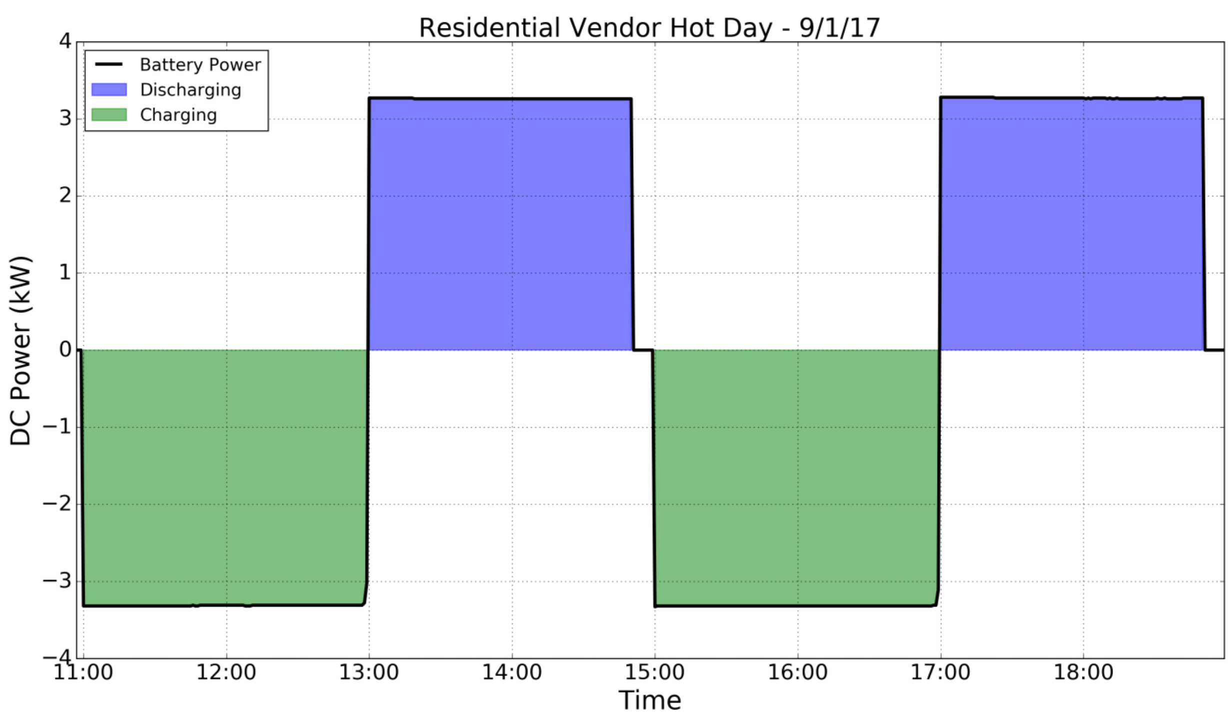

Figure A.4.2: Residential Site Hot Day Performance

Table A.4.1: Residential System Temperature vs. Performance Test Results

	Cool Day (60°F to 63°F)	Hot Day (95°F to 108°F)
Total Charge	-13.25 kWh	-13.26 kWh
Total Discharge	12.09 kWh	12.08 kWh
Performance	0.91	0.91

Cool day performance was calculated as follows:

$$Performance = \left|\frac{12.09}{-13.25}\right| = 0.911$$

Hot day performance was calculated as follows:

$$Performance = \left|\frac{12.08}{-13.26}\right| = 0.912$$

By comparing cool and hot day performance indices, it was concluded that the ambient temperature did not impact the performance of the residential battery system. Performance was gauged on DC Power values, and did not include ancillary loads (e.g., cooling system).

Commercial Sites

Identical to residential site testing protocol, this test consisted of 2 full charge / discharge cycles. The asset was fully discharged before the test began. The 2 full cycles was done between 11:00 and 19:40. During this time period the ambient temperature ranged between 81°F and 91°F. This can be seen in ***Figure A.4.3***. The dip during charging at night was part of a vendor's system check protocol.

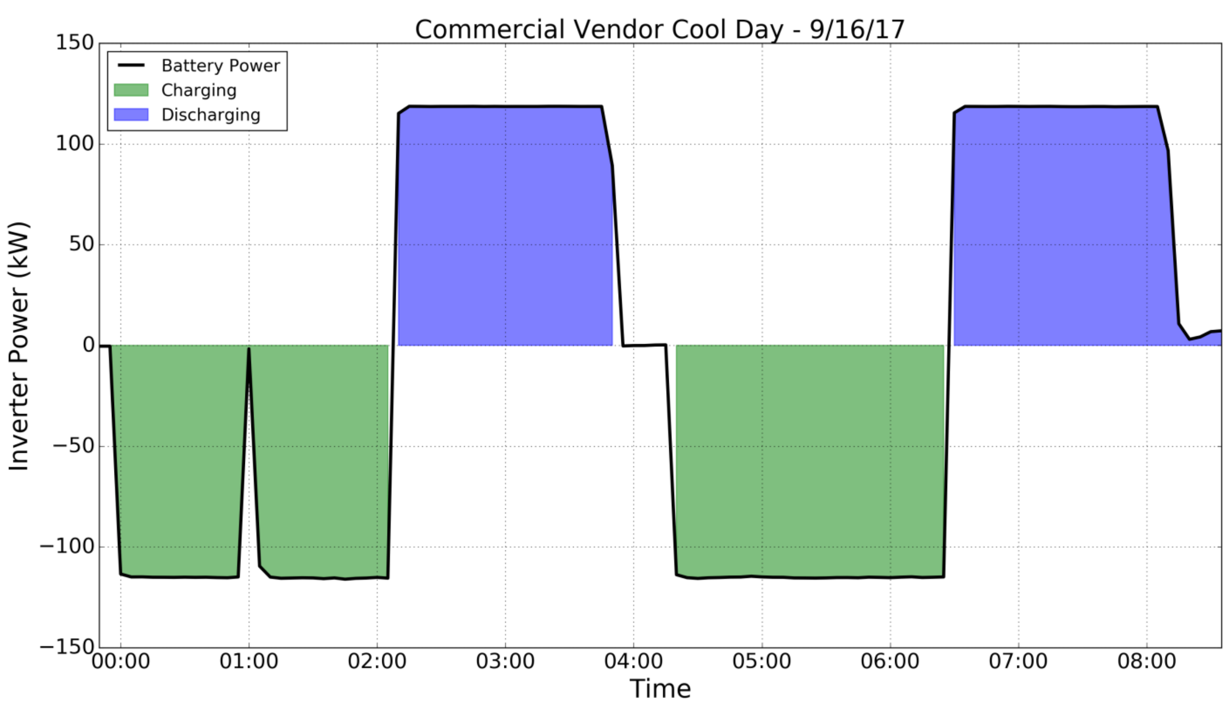

Figure A.4.3: Commercial Site Cool Day Performance

The 2 cycles was repeated again on a different day between 00:00 and 08:40. During this period, the ambient temperature ranged between 60°F and 63°F. This can be seen in ***Figure A.4.4***.

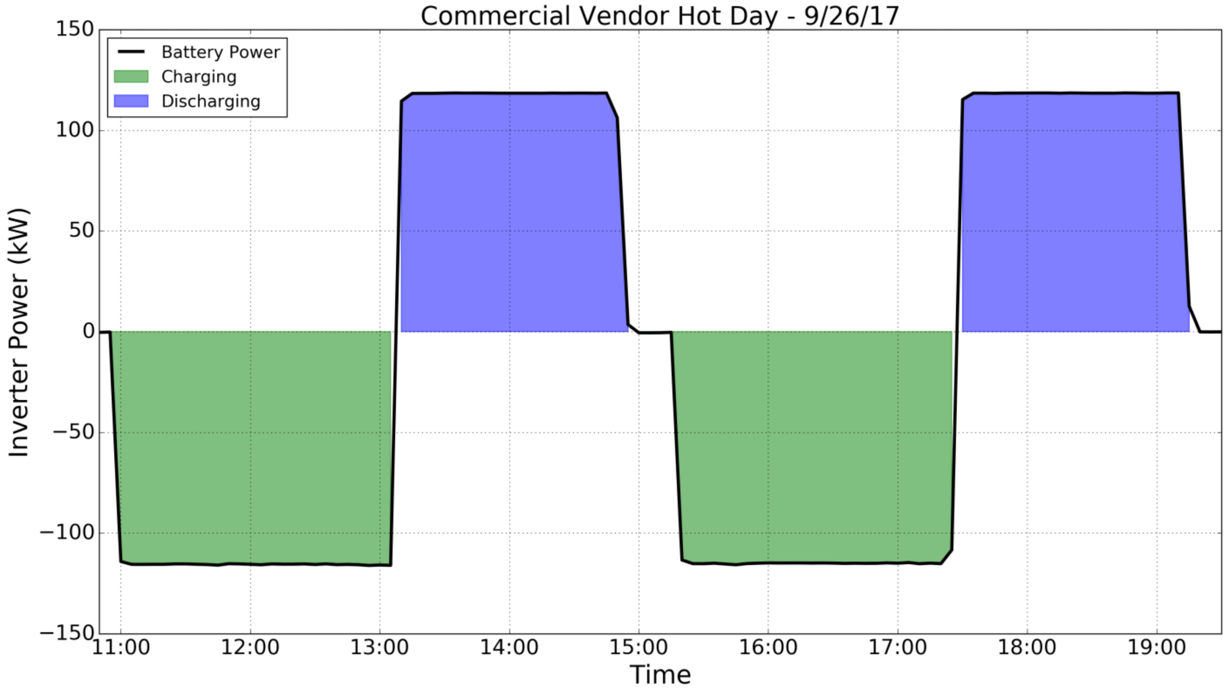

Figure A.4.4: Commercial Site Hot Day Performance

Performance was evaluated as follows:

$$Performance = \left| \frac{\sum_{Start\ Time}^{End\ Time} Real\ AC\ Power\ (kW) > 0}{\sum_{Start\ Time}^{End\ Time} Real\ AC\ Power\ (kW) < 0} \right|$$

If the numerator is divided by 12, it is equivalent to the amount of energy discharged in the time interval. It is necessary to divide by 12 because power was reported every 5 minutes. Therefore, dividing measured (5 min interval) power by 12 was necessary to convert energy to kWh.

Performance was evaluated based on the power measured at the inverters' AC terminals. The results in ***Table A.4.2*** show that a higher ambient temperature caused a 1% drop in battery performance. It is important to note that none of the auxiliary load associated with the battery system were not measured and those will have a temperature dependence. The battery's HVAC system will draw more power on the hot day which would further lower the total round trip efficiency of the battery system. The vendor communicated that their HVAC units draw a maximum power of 1 kVA for each tower. The systems in this project were comprised of 4 towers, resulting in a maximum HVAC load of 4 kVA or 3.3% of the system rating. The load dependence on temperature has not been characterized.

Table A.4.2: Commercial System Temperature vs. Performance Test Results

	Cool Day (60°F to 63°F)	Hot Day (81°F to 91°F)
Total Charge	-489.13 kWh	-499.13 kWh
Total Discharge	412.85 kWh	414.32 kWh
Performance	0.84	0.83

10.5 Load Profile

Eclipse Forecast

The PG&E Meteorology team provides a 4-day irradiance forecast in a 1 hour interval, and a 4-hour forecast in a 15-minute interval. Irradiance is expressed as Solar Performance Index which is a normalized irradiance unit. The 4-hour forecast was downloaded on the morning of August 18 to cover the time period of the eclipse which was from 09:00 to 11:45. In this document, this forecast will be referred to as the "Reference Forecast." Also, the solar generation values from 09:00 to 11:45 on August 1 will be referred to as the "Reference Generation." August 1 solar production data was chosen as a it was a most recent clear sky day when no curtailment commands were sent to the inverters.

On the morning of the eclipse at 08:30 the 4-hour forecast was downloaded. In this document, this forecast will be referred to as the "Eclipse Forecast". The expected solar generation which will be referred to as the "Eclipse Generation" was calculated by multiplying the ratio of the Eclipse Forecast and the Reference Forecast by the Reference Generation. This is shown in the following equation:

$$Generation_{Eclipse} = \frac{Forecast_{Eclipse}}{Forecast_{Reference}} * Generation_{Reference}$$

The required battery discharge is the difference between the Reference Generation and the Eclipse Generation. This is shown in the following equation:

$$Battery\ Discharge = Generation_{Reference} - Generation_{Eclpise}$$

By combining previous two equations, the required battery discharge schedule was calculated based on the following equation:

$$Battery\ Discharge = \left(1 - \frac{Forecast_{Eclipse}}{Forecast_{Reference}}\right) * \ Generation_{Reference}$$

The Reference Generation was in 1 minute interval, while the forecast data was in 15-minute interval. To synchronize the time intervals, the 15 minutes of Reference Generation data centered on the Forecast reporting interval was averaged. Two assets were scheduled in 15 minute intervals. The Forecast was also interpolated to create a 5 minute and 1 minute interval. The same averaging strategy for the Generation data was used with the 5-minute interval and no averaging was required for the 1 minute interval data. Two other assets were scheduled in 5 minute intervals and one more asset was scheduled in 1 minute interval.

Residential Sites

Test results are shown in ***Figure A.5.1*** through ***Figure A.5.5***. As shown in ***Figure A.5.4***, the scheduled battery discharge at the site #4 was much greater than the loss in solar generation. After investigating, it was discovered that for some reason, the solar system at this site started producing less energy from mid to late August, and then went back to its normal energy production levels. This caused error in over estimating solar generation at this site during the eclipse.

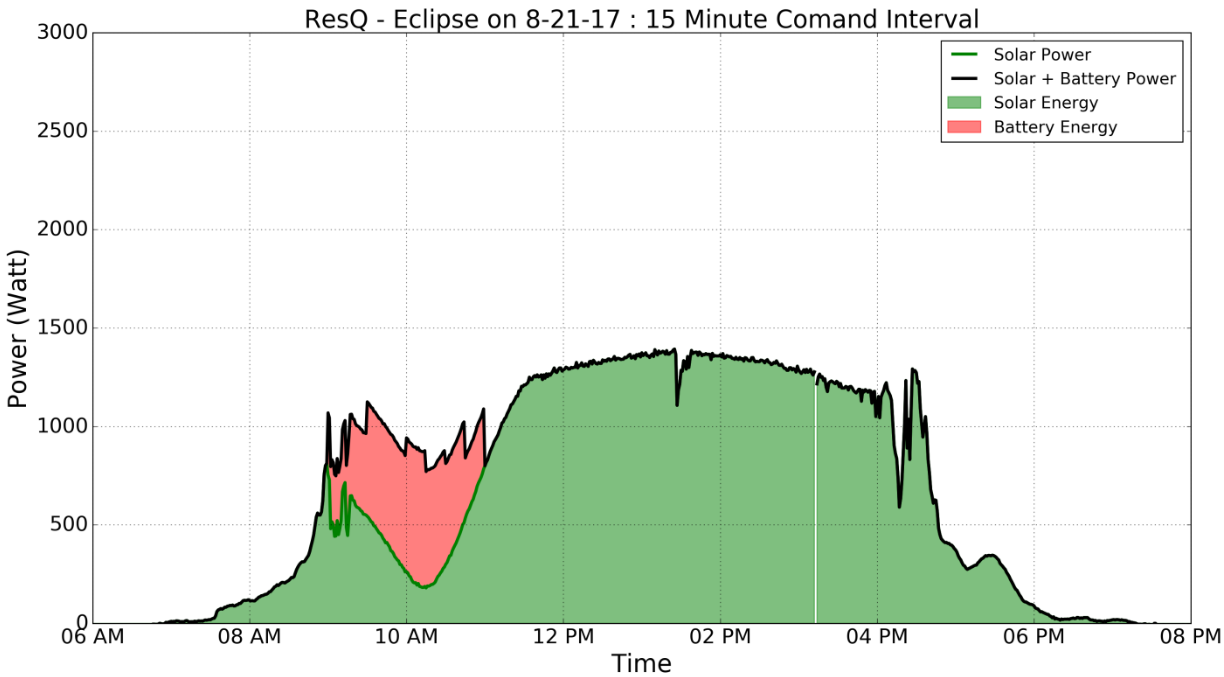

Figure A.5.1 – Eclipse Compensation at Asset #1 – 15 Minute Interval Command

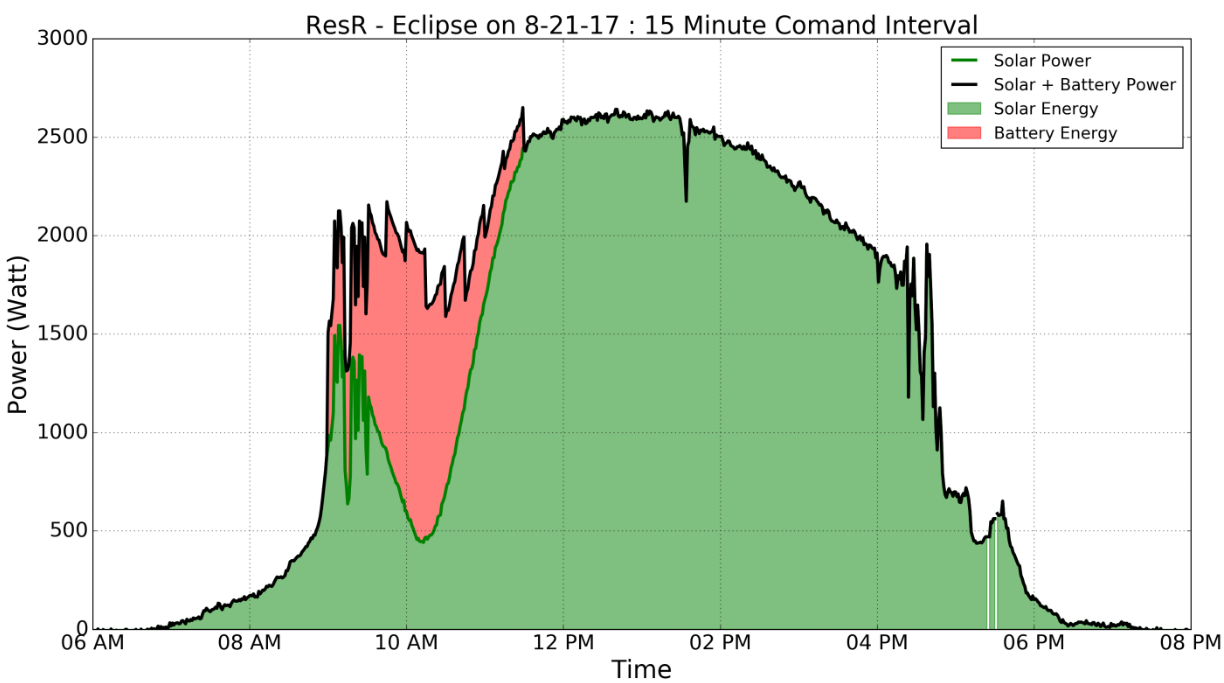

Figure A.5.2 – Eclipse Compensation at Asset #2 – 15 Minute Interval Command

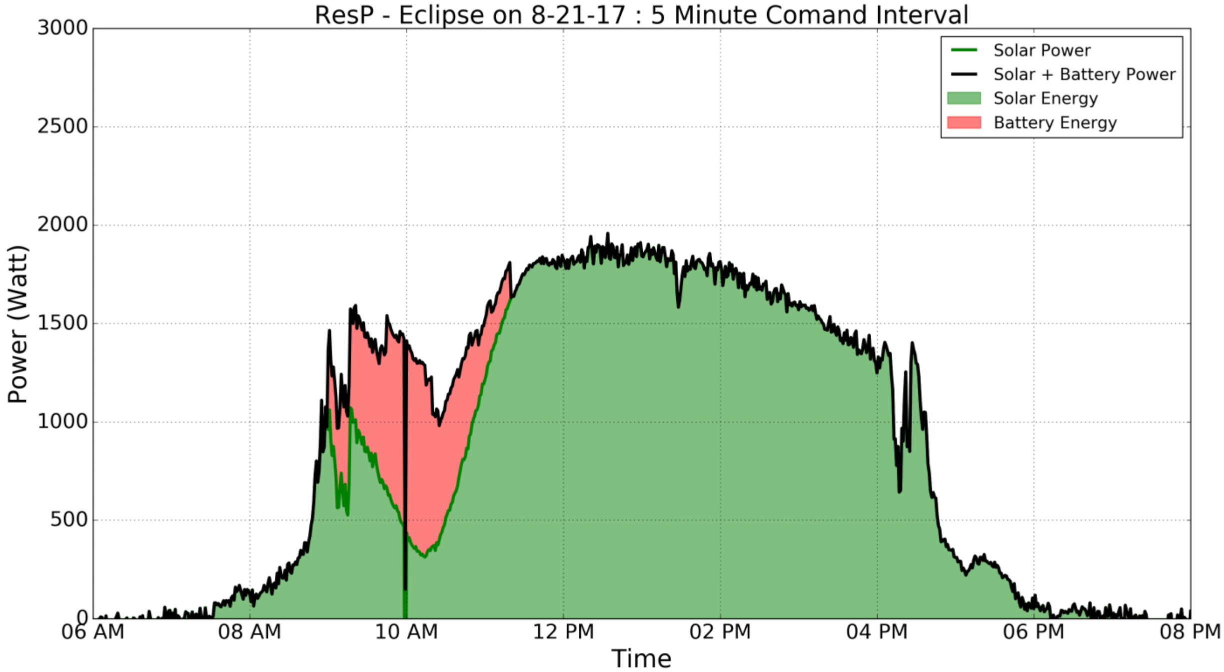

Figure A.5.3 – Eclipse Compensation at Asset #3 – 5 Minute Interval Command

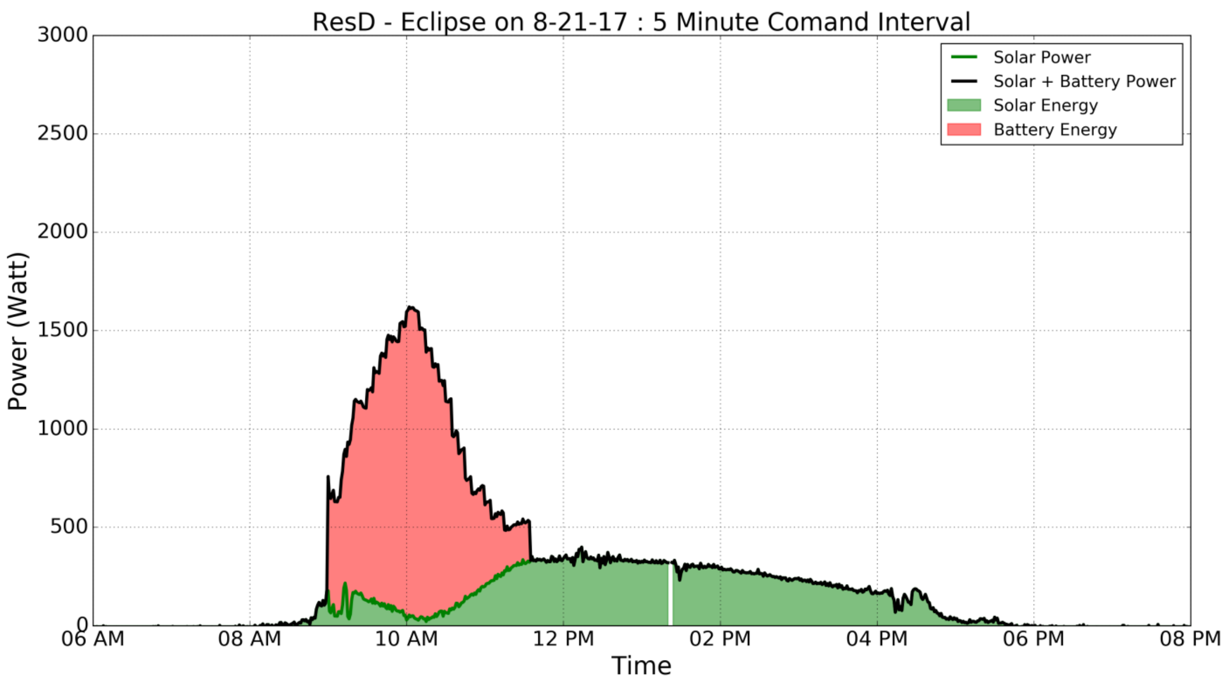

Figure A.5.4 – Eclipse Compensation at Asset #4 – 5 Minute Interval Command

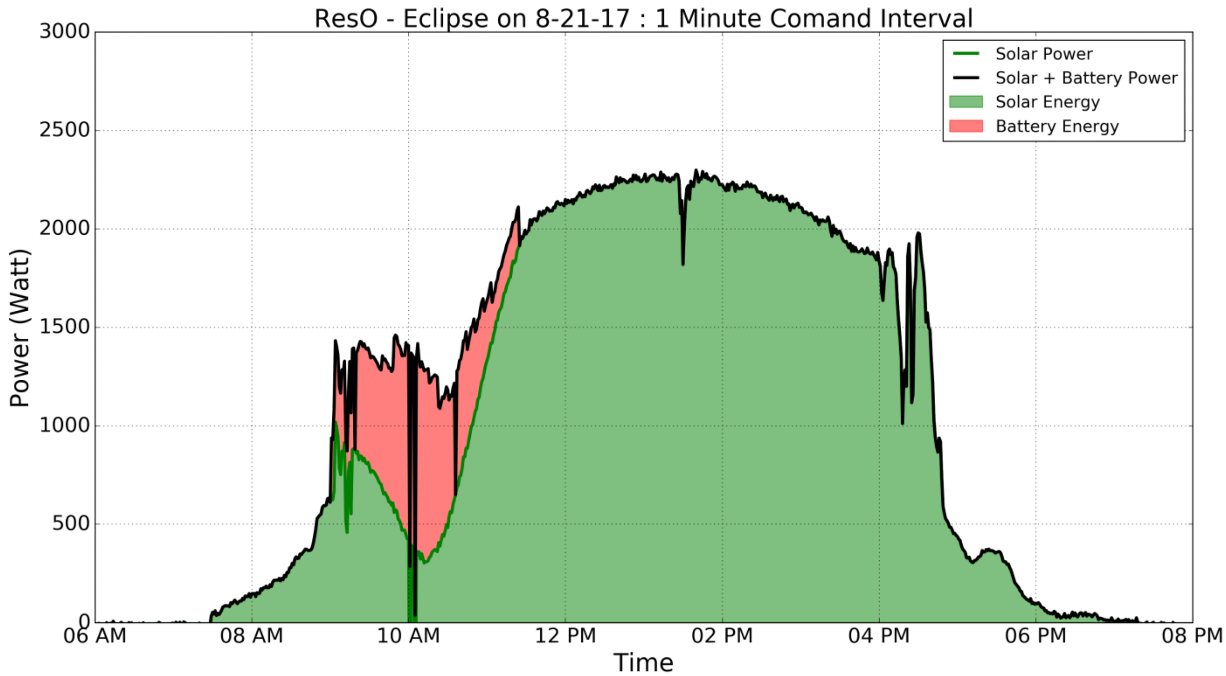

Figure A.5.5 – Eclipse Compensation at Asset #5 – 1 Minute Interval Command

Commercial Site

The test leveraged the vendor's peak shaving algorithm. The test ran uninterrupted for a week at one of the commercial sites where the project deployed energy storage. The 15-minute interval data for this test was downloaded from the vendor's web portal. From acquired data, the building's Gross load was calculated by subtracting the net load and battery system's power.

The building's gross and net load for all 7 days is shown in ***Figure A.5.6*** through ***Figure A.5.12***. The gross and net load profile shapes indicate that the peak shaving algorithm was effective in flattening the site load.

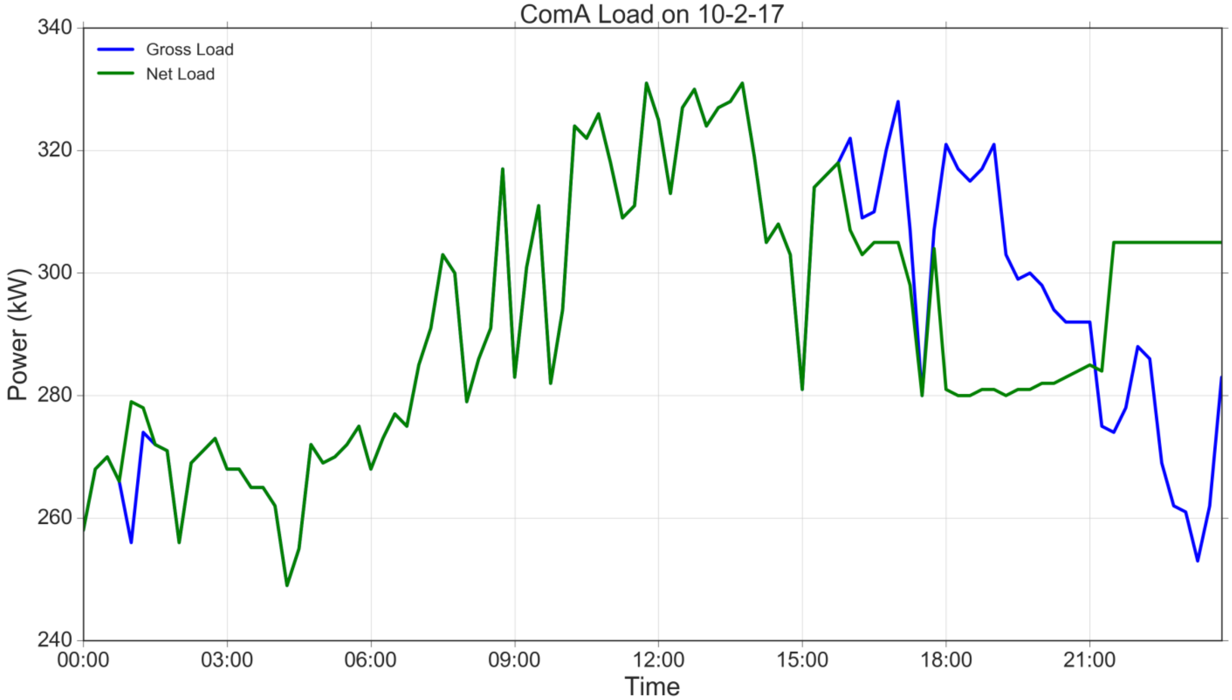

Figure A.5.6 – Commercial Site Load Profile on Day 1

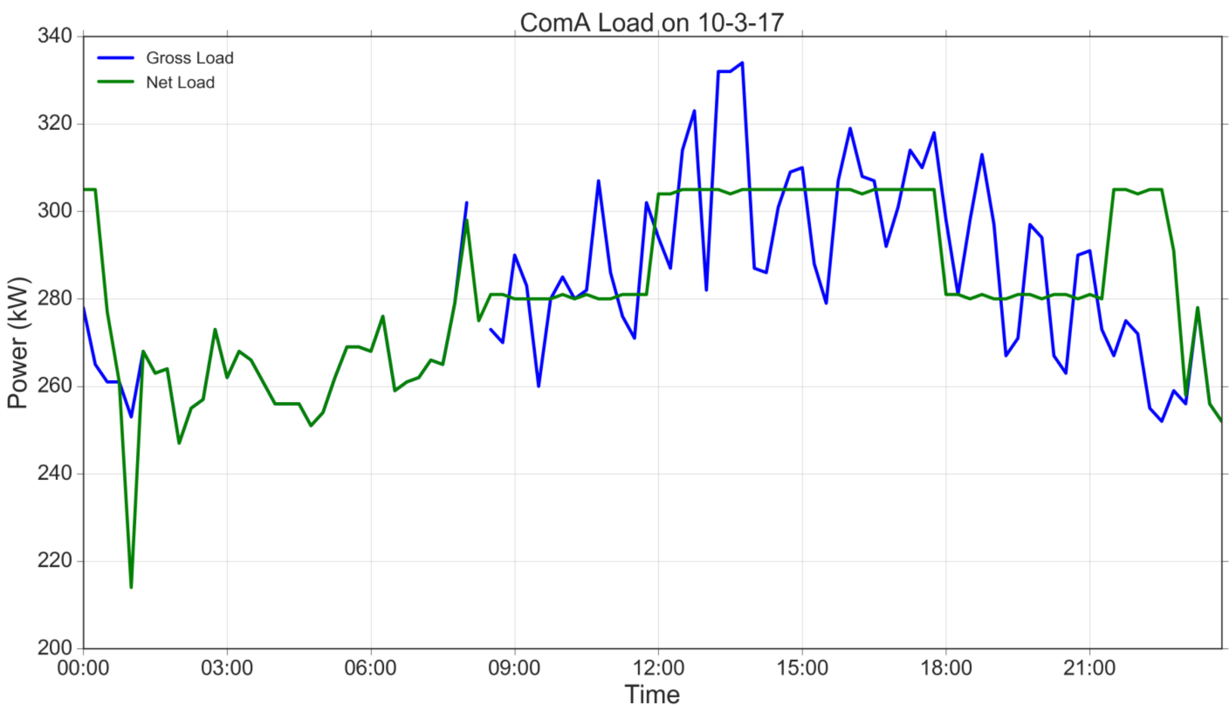

Figure A.5.7 – Commercial Site Load Profile on Day 2

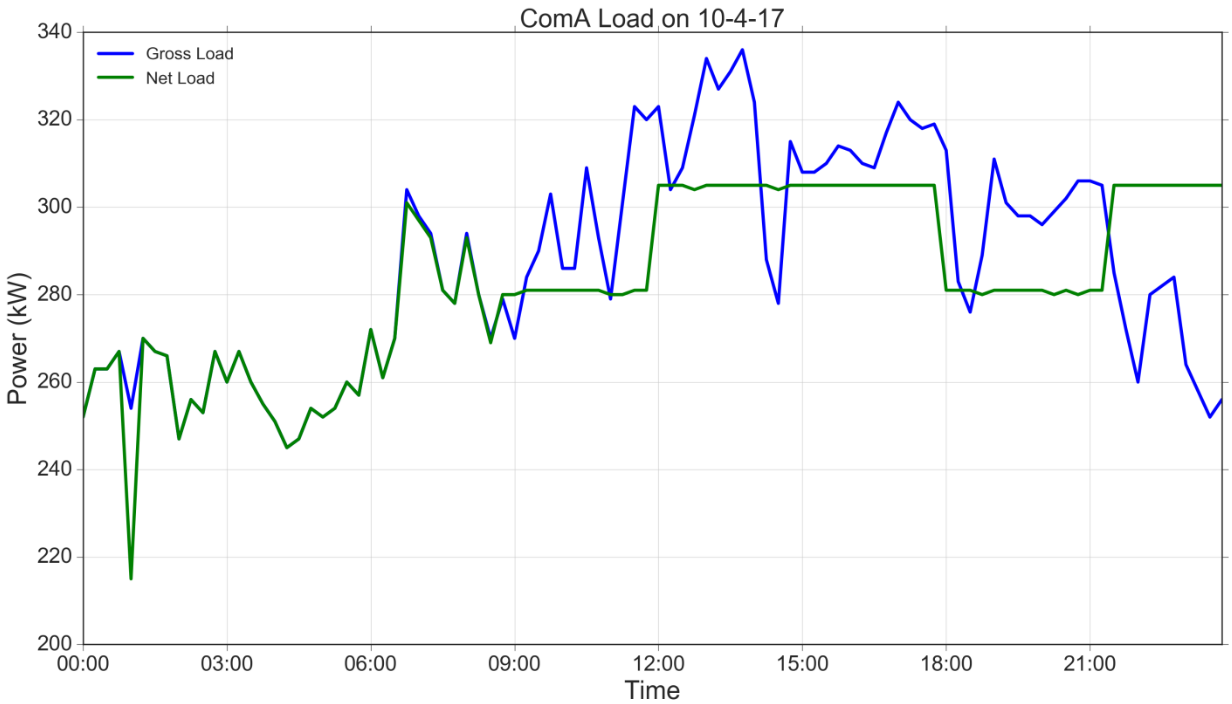

Figure A.5.8 – Commercial Site Load Profile on Day 3

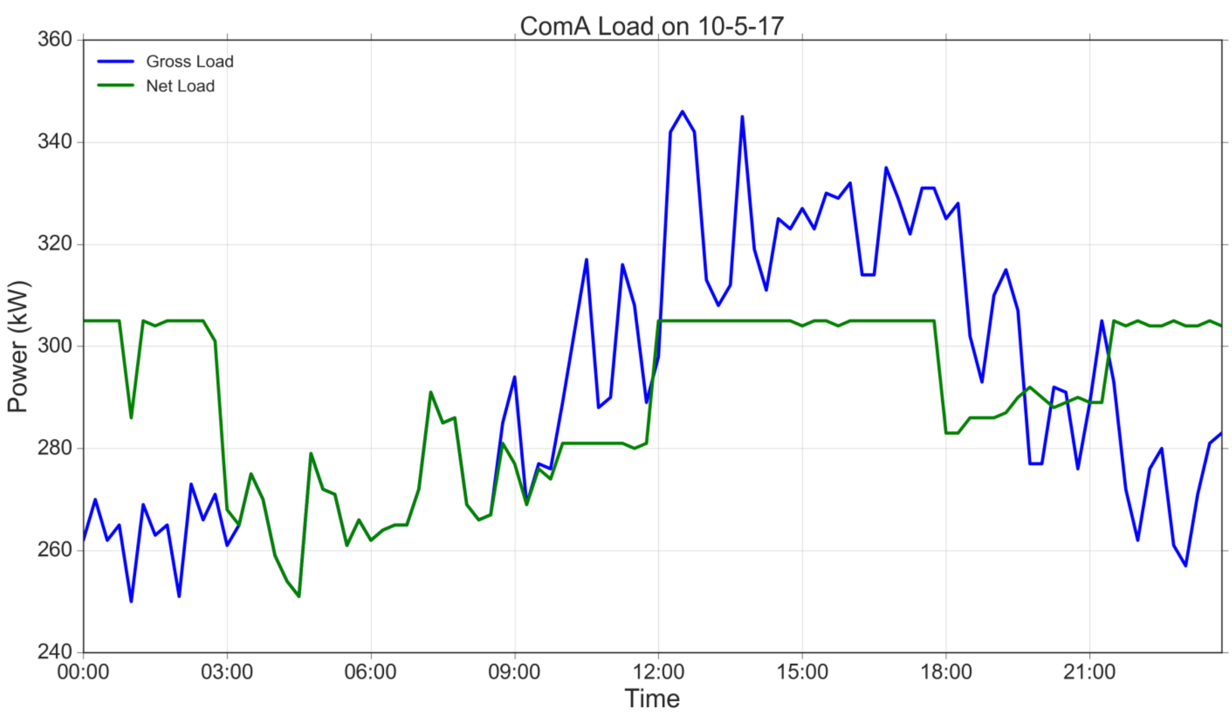

Figure A.5.9 – Commercial Site Load Profile on Day 4

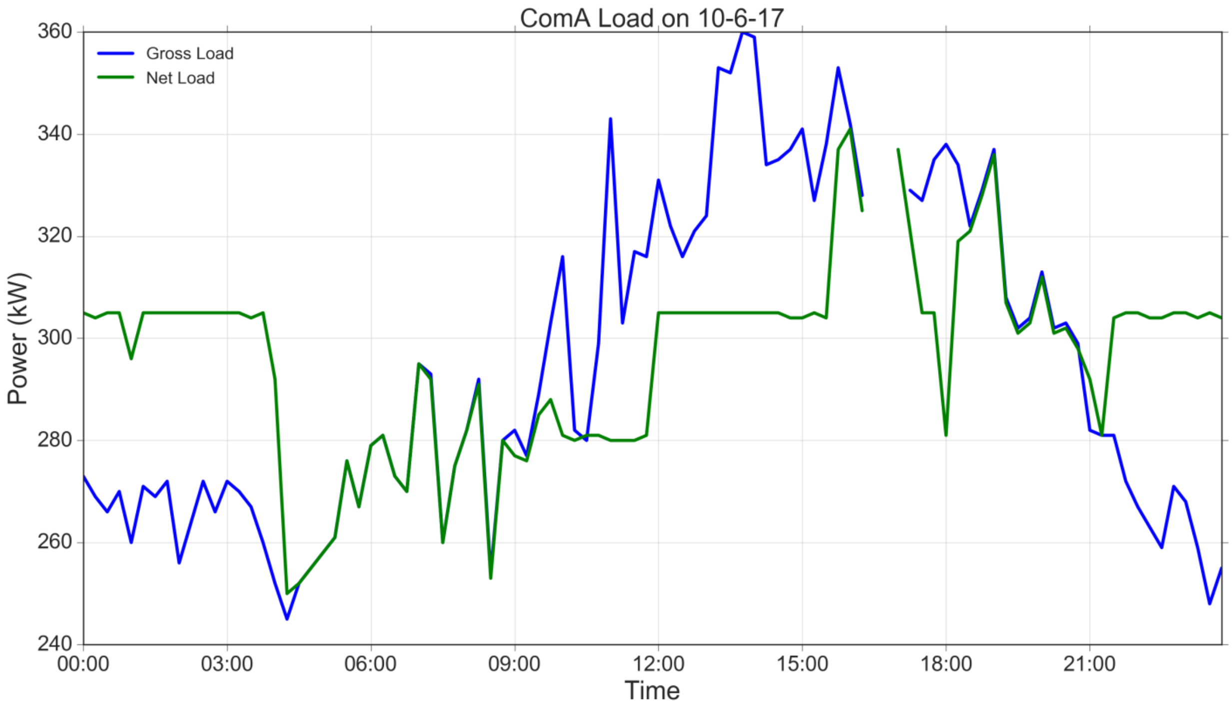

Figure A.5.10 – Commercial Site Load Profile on Day 5

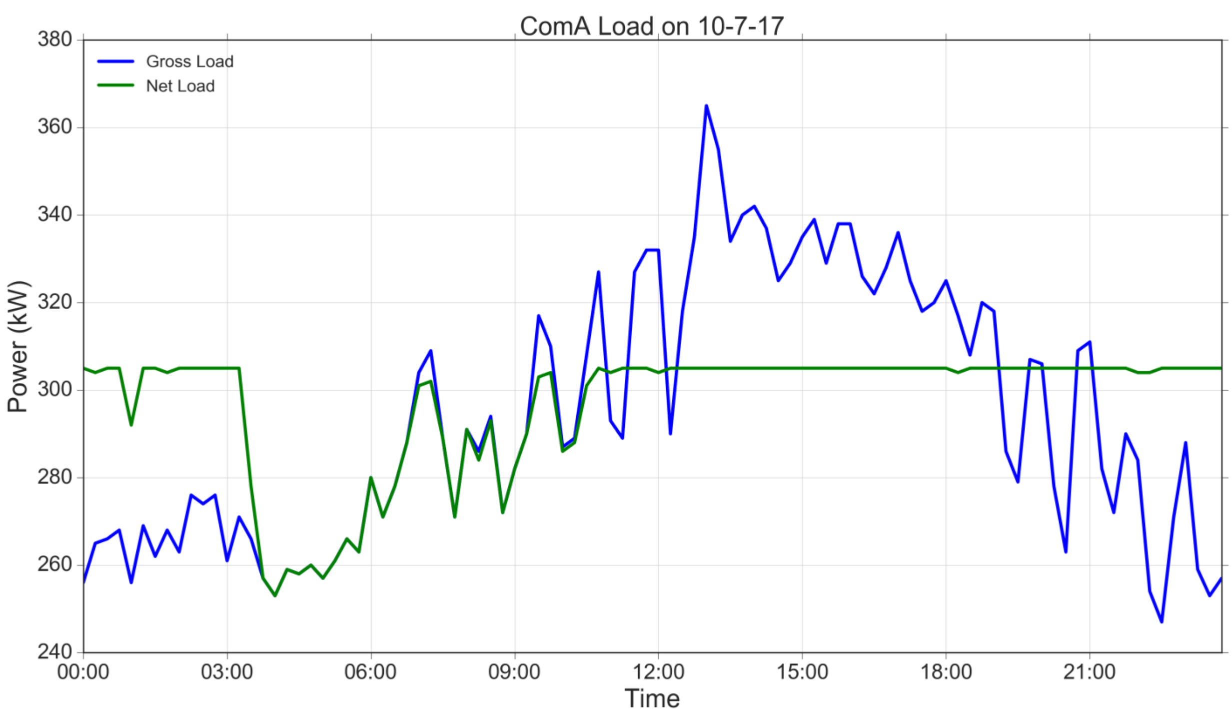

Figure A.5.11 – Commercial Site Load Profile on Day 6

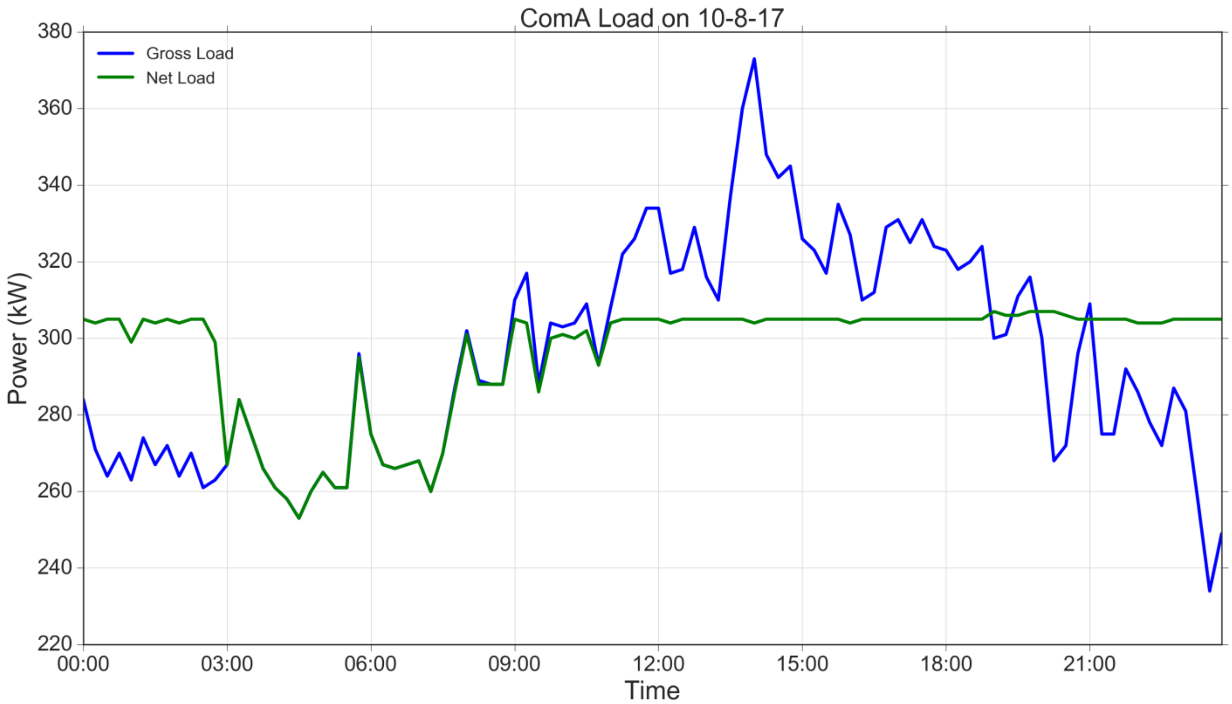

Figure A.5.12 – Commercial Site Load Profile on Day 7

10.6 Battery Charge Only from Solar

Test results apply only on residential sites.

Table A.6.1 - Daily Solar Energy Production on Single Battery Systems

		Summer: July 1st - September 21st			Fall: September 22nd - December 14th		
Single Battery Asset #	DC Size (kW)	Number of Test Days	Greater than 6.4 kWh of Solar Production		Number of Test Days	Greater than 6.4 kWh of Solar Production	
			# of days	Full SoC Success Rate		# of days	Full SoC Success Rate
1	2.60	43	41	95%	62	1	2%
2	2.86	34	33	97%	72	18	25%
3	2.86	0	0	N/A	47	1	2%
4	3.12	37	37	100%	57	49	86%
5	3.38	0	0	N/A	11	10	91%
6	3.38	35	35	100%	64	48	75%
7	3.38	12	12	100%	62	54	87%
8	4.16	0	0	N/A	56	52	93%
9	4.16	47	47	100%	24	22	92%
10	6.24	13	13	100%	44	43	98%
11	7.56	0	0	N/A	69	67	97%
12	8.50	0	0	N/A	67	66	99%

Table A.6.2 - Daily Solar Energy Production on Dual Battery Systems

		Summer: July 1st - September 21st			Fall: September 22nd - December 14th		
Dual Battery Asset #	DC Size (kW)	Number of Test Days	Greater than 6.4 kWh of Solar Production		Greater than 6.4 kWh of Solar Production	Greater than 12.8 kWh of Solar Production	
			# of days	# of days		# of days	Full SoC Success Rate
1	2.60	39	28	72%	72	8	11%
2	3.29	43	40	93%	69	44	64%
3	4.42	0	0	N/A	41	25	61%
4	5.04	0	0	N/A	70	19	27%
5	5.46	0	0	N/A	50	41	82%
6	6.24	0	0	N/A	59	51	86%
7	8.19	31	31	100%	34	34	100%

10.7 Metering Validation

Residential Sites

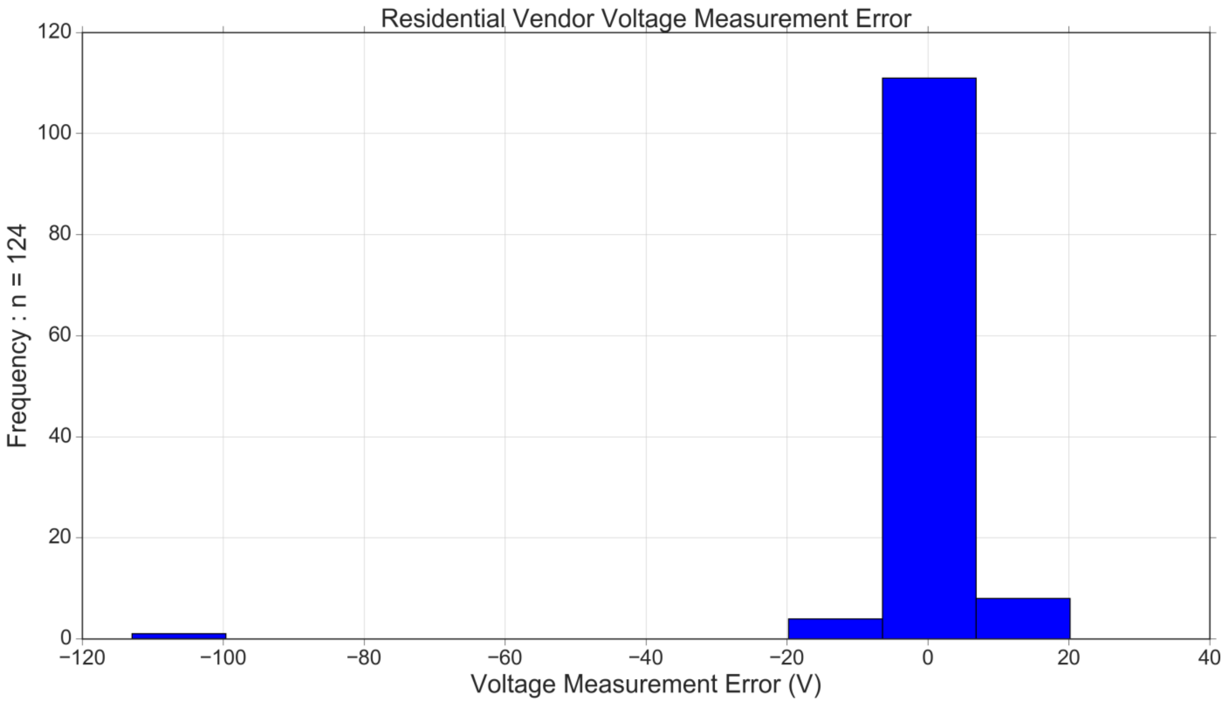

Figure A.7.1: Voltage Measurement Error

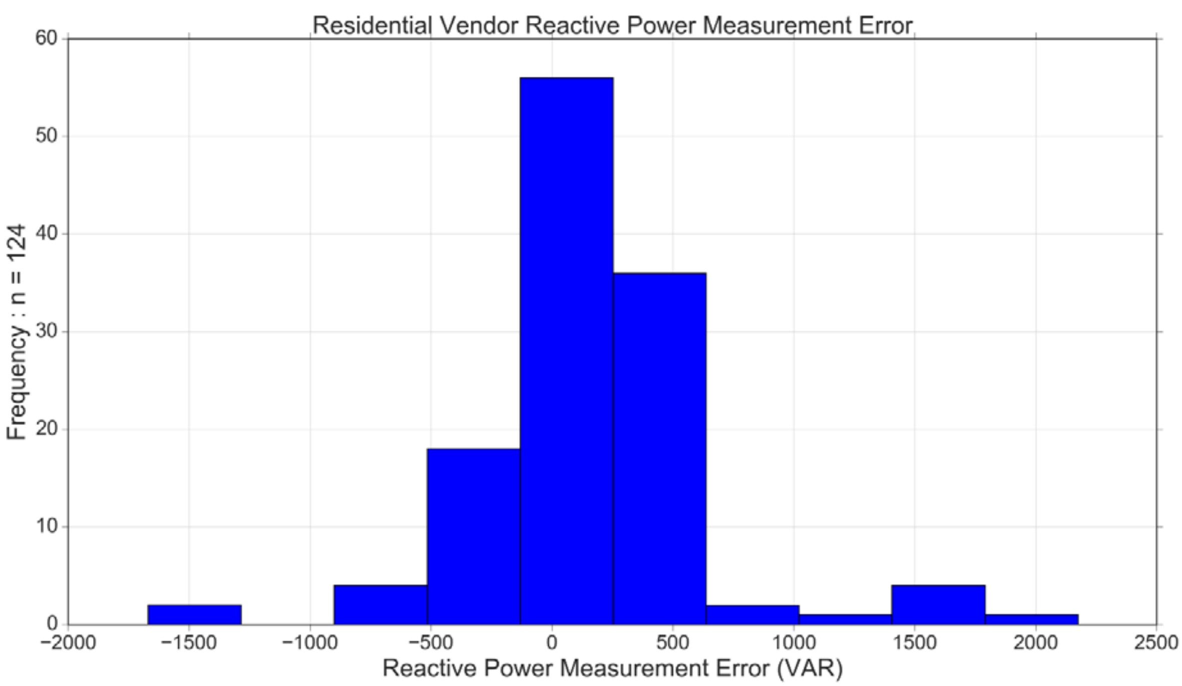

Figure A.7.2: Reactive Power Measurement Error

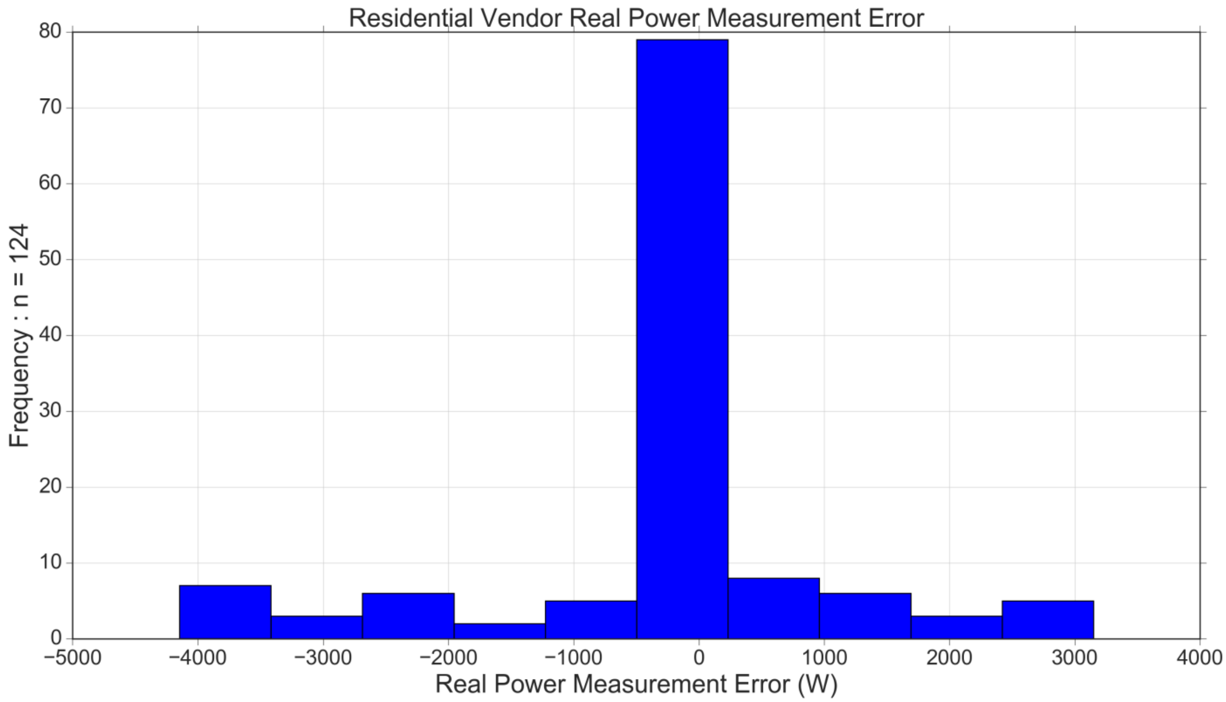

Figure A.7.3: Real Power Measurement Error

The range of measurement error was very large, mainly because of the way the measurements from the inverter were reported. The inverter's instantaneous measurements are collected approximately every 10 second. The measurements with the timestamp after the minute and closest to the minute were used to represent the minute. The underlying assumption in this data reporting method was that no changes happen within the minute. This was not the case with the testing that was done in the lab. Some tests had rapid changes in voltage and power within the minute. The following threshold values were used for filtration, and the resulting distributions are shown in ***Figure A.7.4.*** through ***A.7.6.***

- Maximum Voltage Change = 0.24 V
- Maximum Reactive Power Change = 500 VAR
- Maximum Real Power Change = 100 W

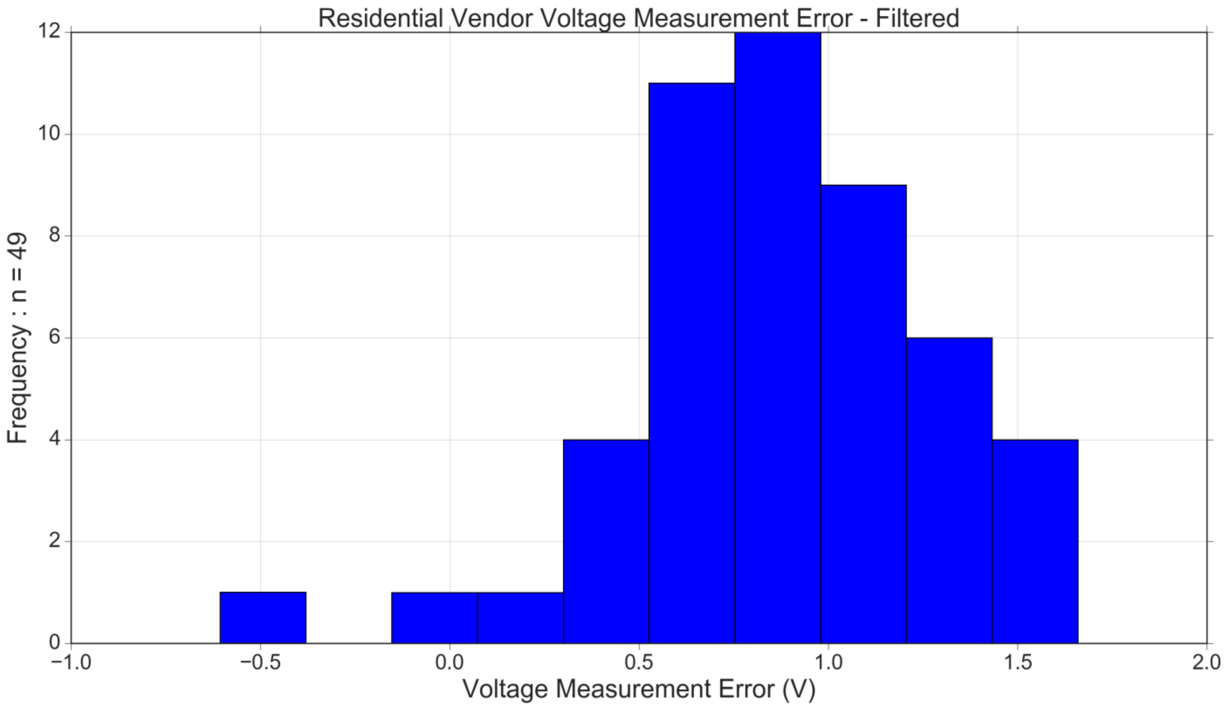

Figure A.7.4: Voltage Measurement Error After Filtration

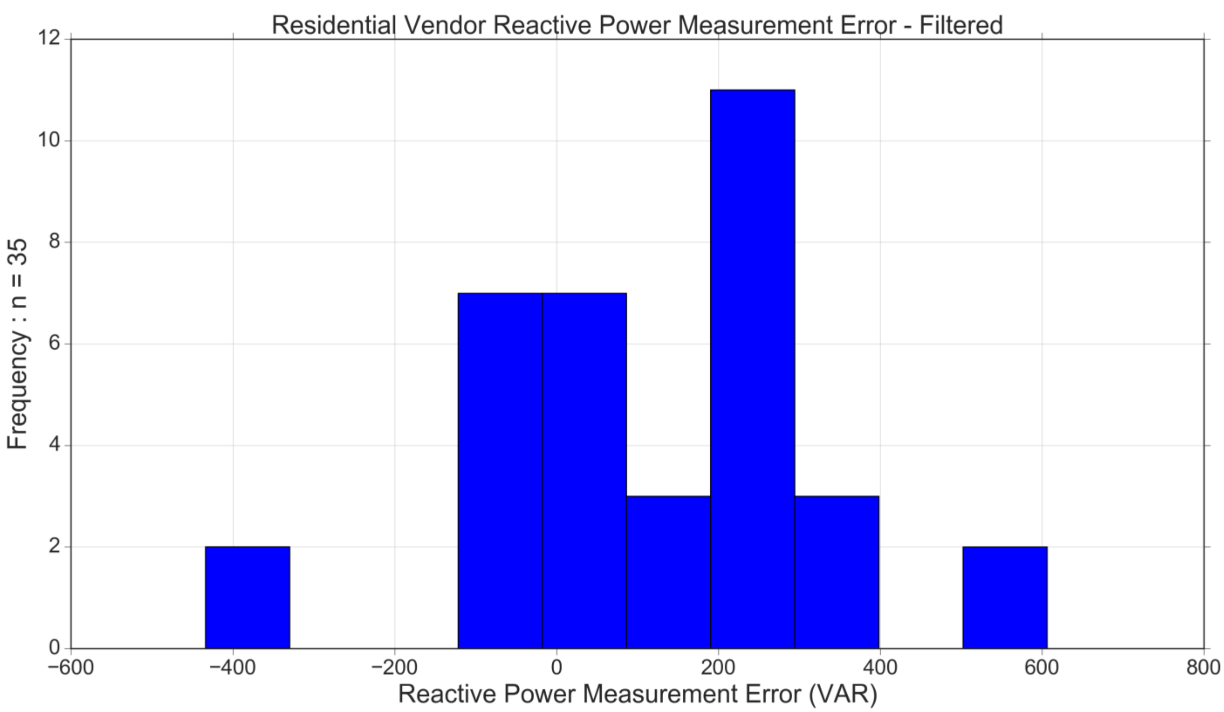

Figure A.7.5: Reactive Power Measurement Error After Filtration

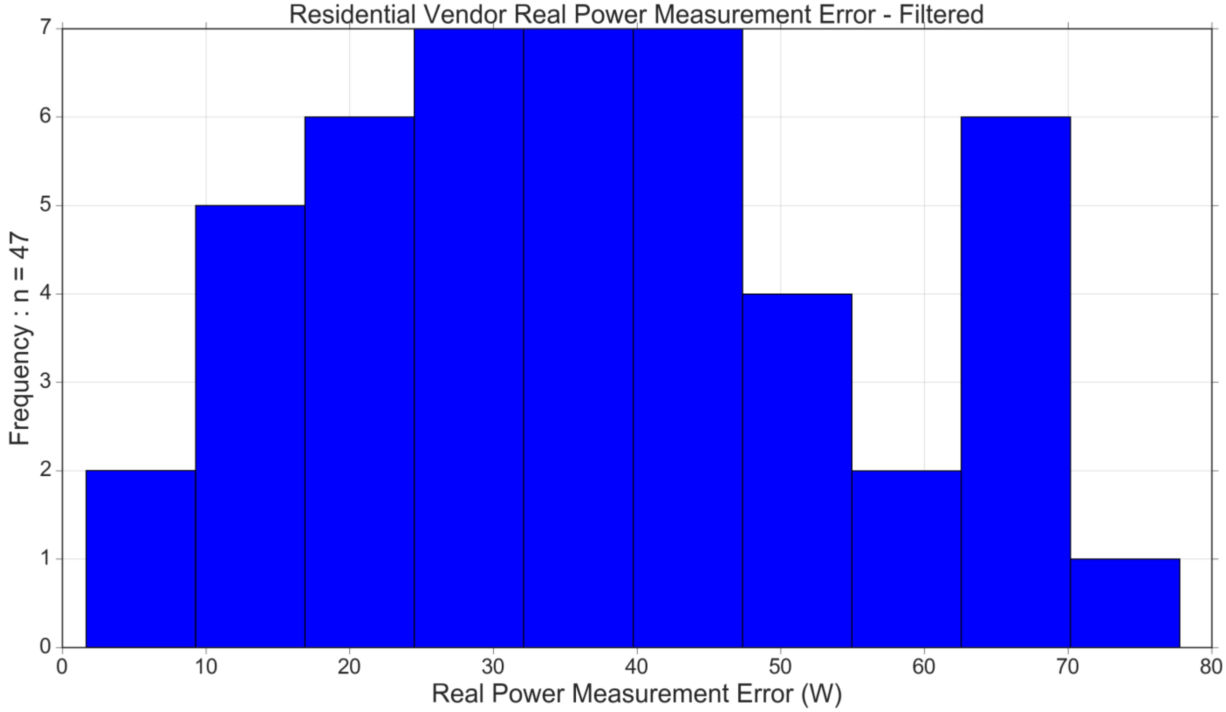

Figure A.7.6: Real Power Measurement Error After Filtration and without Outlier

With the steady state filter, the summarized measurement error is shown in ***Table A.7.1***. The range of error with 95% probability and 99% probability were solved for by multiplying the standard deviation by 2 and 2.6 respectively.

Table A.7.1: Residential Vendor Measurement Error Summary

Measurement	Mean Error	Median Error	Standard Deviation of Error	Range of Error with 95% Probability	Range of Error with 99% Probability
Voltage	0.88 V	0.88 V	0.40 V	0.08 to 1.68 V	-0.16 to 1.92 V
Reactive Power	110 VAR	121 VAR	217 VAR	-324 to 544 VAR	-454 to 674 VAR
Real Power	37.6 W	36.9 W	17.9 W	1.8 to 73.4 W	-8.9 to 84.1 W

In the context of a 3.3 kW battery discharge, the error in reported power would be approximately 1% but can be as high as 2.5%. The high standard deviation of reactive power measurement error was because the inverter typically oscillated +/- 200 VAR in normal operation.

Table A.7.2: Lab Metering Traceability

CO MTE ID	Serial	Make	Model	Description
ATSICR-100354	201523717	Verivolt	ISOBLOCK I-FG 60A:10V	Transducer, Current
ATSICR-100355	201523723	Verivolt	ISOBLOCK I-FG 60A:10V	Transducer, Current
ATSICR-100356	201526038	Verivolt	ISOBLOCK V 1000V:10V	Transducer, Voltage
ATSICR-100357	153289C-01L 1A70095	National Instruments	NI-9220	Module, Analog, Input

Commercial Site

Table A.7.3 shows the traceability of a power quality meter (PQM) installed at the battery system's AC disconnects at one of the commercial sites.

Table A.7.3: Power Quality Meter Traceability

CO MTE ID	Serial	Make	Model	Description
ATSICR-100942	14604	PMI	Revolution	Recorder, Wireless Power Quality

In addition to the 1 min interval PQM data, 5 minutes averaged 1 second data from the inverter terminals was collected. Error was calculated by the following equation:

$$X_{error} = X_{Vendor\ Charge\ Reported} - X_{PQM\ Measured}$$

With this definition, if vendor reports a value higher that what is measured by PQM, the error is positive. If vendor reports a value lower that what is measured, the error is negative.

The distribution of measurement error for real power are shown in ***Figure A.7.7*** through ***Figure A.7.9***.

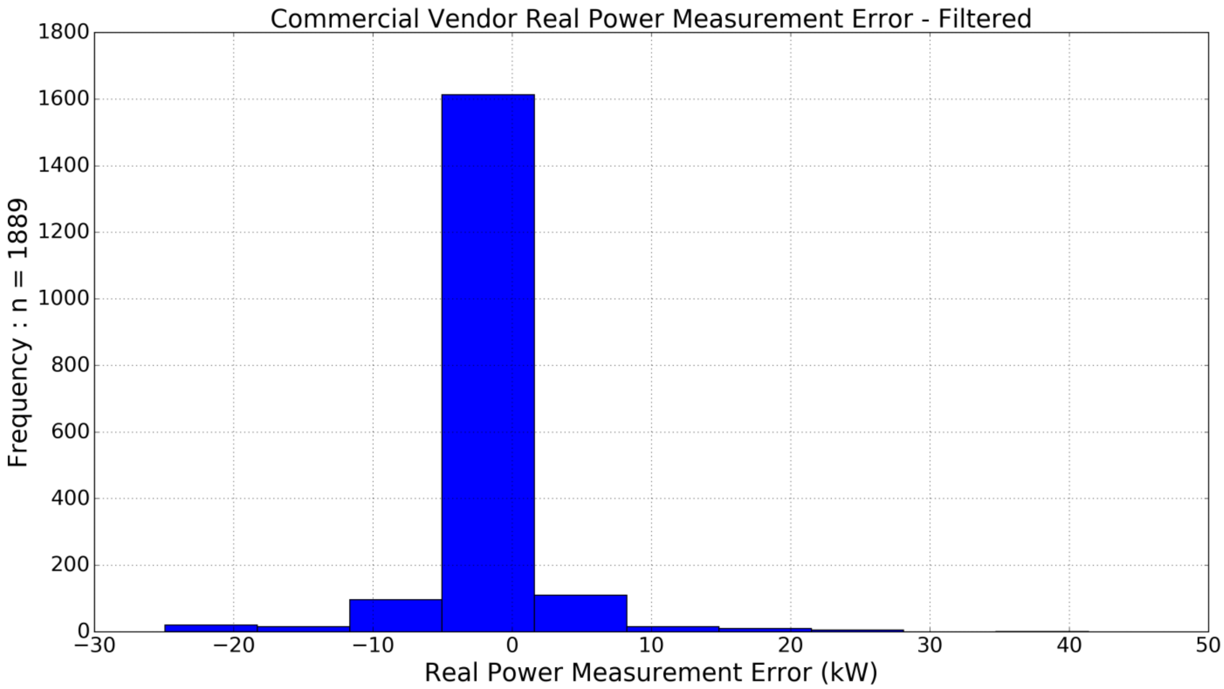

Figure A.7.7: Real Power Measurement Error

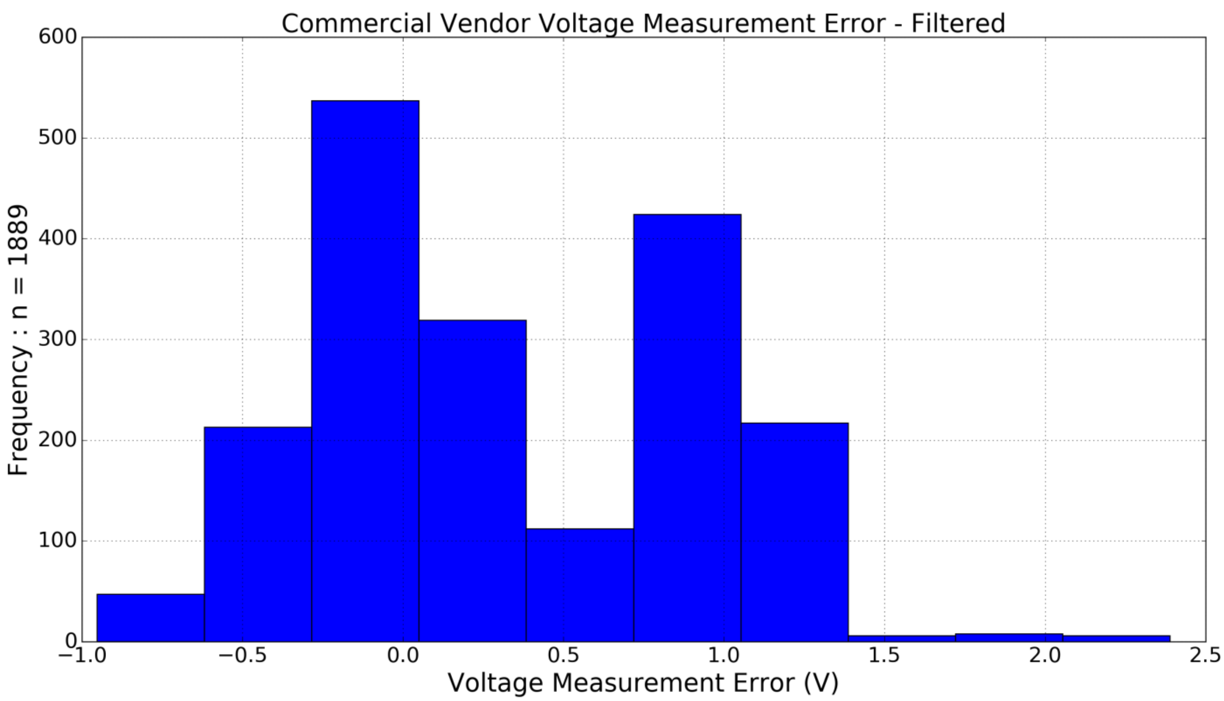

Figure A.7.8: Voltage Measurement Error

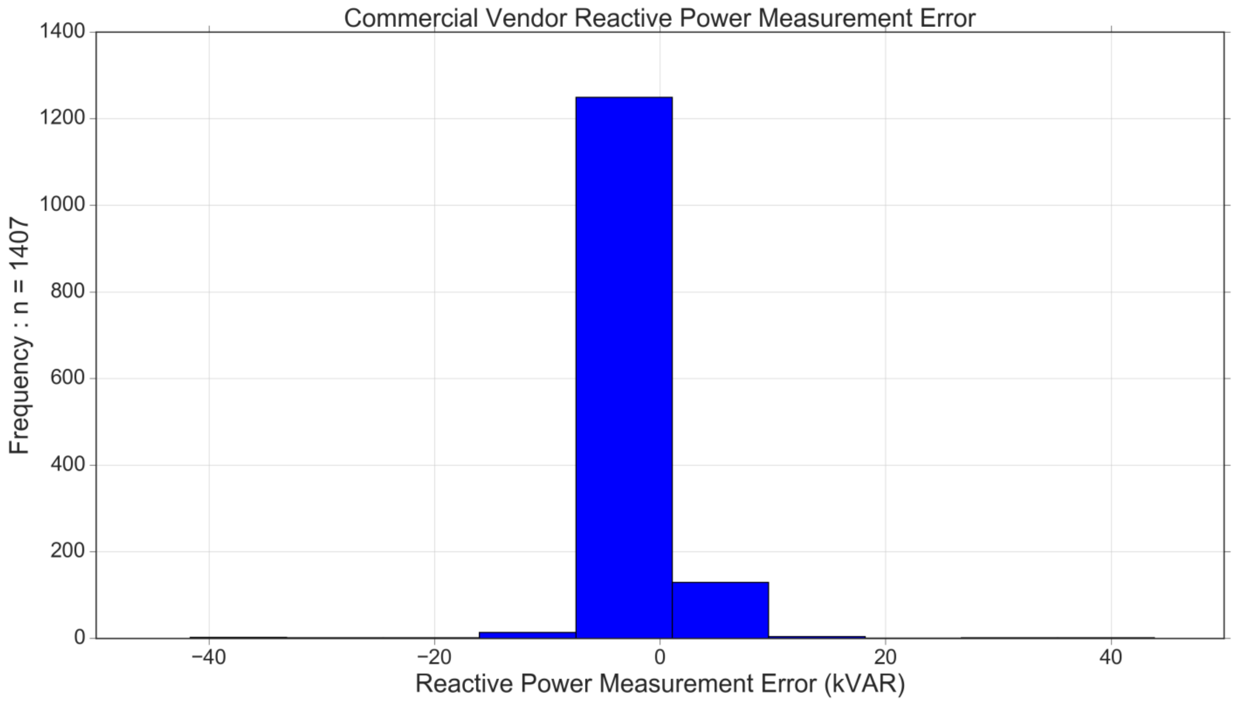

Figure A.7.9: Reactive Power Measurement Error

The measurement error is summarized in ***Table A.7.4***.

Table A.7.4: Measurement Error Summary

Measurement	Mean Error	Median Error	Standard Deviation of Error	Range of Error with 95% Probability	Range of Error with 99% Probability
Voltage	0.33 V	0.10 V	0.57 V	-0.82 to 1.47 V	-1.16 to 1.82 V
Reactive Power	-1.68 kVAR	-1.88 kVAR	3.70 kVAR	-9.08 to 5.71 kVAR	-11.3 to 7.94 kVAR
Real Power	-1.56 kW	-1.47 kW	4.09 kW	-9.73 to 6.61 kW	-12.2 to 9.06 kW

In the context of a 60 kW discharge, the error in real power would be on average 2.6%. A large part of this error can be attributed to the HVAC systems whose load is not captured in the inverter measurements.

The spread on accuracy was large which resulted in a possible error range of 20% with a 99% probability. The cause of the large spread in error is not known but it is suspected that the aggregation and averaging across 4 inverter over 5 minutes is the culprit. It is recommended that commercial battery systems have a single meter with all inverters and ancillary loads behind it.