Pacific Gas and Electric Company

EPIC Final Report

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ADC	Application Delivery Control
ADER	Aggregated Distributed Energy Resource
ADMS	Advanced Distribution Management System
AHJ	Authority Having Jurisdiction
BTM	Behind the Meter
CAISO	California Independent System Operator
CPUC	California Public Utilities Commission
DER	Distributed Energy Resource
DERMS	Distributed Energy Resource Management System
DERPA	Distributed Energy Resource Provider Agreement
DMS	Distribution Management System
DMZ	Demilitarized Zone (Computing)
DR	Demand Response
DRP	Distribution Resources Plan
DRP-A	Demand Response Provider Agreement
ECDHE	Elliptic-curve Diffie-Hellman Exchange
EPIC	Electric Program Investment Charge
EPRI	Electric Power Research Institute
ESS	Energy Storage Systems
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission
FLISR	Fault Location, Isolation, and Service Restoration
FTM	Front of the Meter
GHG	Greenhouse Gas
GRC	General Rate Case
HTTPS	Hypertext Transfer Protocol Secure

IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronic Engineers
IGP	Integrated Grid Platform
IT	Informational Technology
kVAR	Kilo Volt Ampere Reactive
kW	Kilowatt
LMP	Locational Marginal Pricing
MAPE	Mean Average Percent Error
MILP	Mixed Integer Linear Programming
MUA	Multiple Use Applications
MVP	Minimum Viable Product
MW	Megawatt
NGR	Non-generating Resource
NIST	National Institute of Standards and Technology
OpenADR	Open Automated Demand Response
PDR	Proxy Demand Resource
PG&E	Pacific Gas & Electric
PMU	Phasor Measurement Unit
PV	Photovoltaic
QSTS	Quasi-Static Time Series
RFP	Request for Proposal
SCADA	Supervisory Control and Data Acquisition
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SEP2	Smart Energy Profile 2.0
SEPA	Smart Electric Power Alliance
SIWG	Smart Inverter Working Group
SoC	State of Charge
SSP II	Supply Side II DR Pilot
STES	Short Term Electric Supply
TD&D	Technology Demonstration and Deployment
VVO	Volt VAR Optimization
XSP	Excess Supply DR Pilot
YB BESS	Yerba Buena Battery Energy Storage System

1 Executive Summary

This report summarizes the project objectives, technical results and lessons learned for EPIC Project 2.02 - Distributed Energy Resource Management System (DERMS), as listed in the Electric Program Investment Charge (EPIC) Annual Report, also referred to as EPIC 2.02 – DERMS.

1.1 DERMS Project Context

California is a leader in the growth of Distributed Energy Resources (DERs) including solar, battery storage, electric vehicles (EVs), and load controlled by demand response (DR). This progress is driven by a confluence of technology advancements, consumer preferences, and complementary legislative and regulatory actions that have propelled solar and energy storage installations and EVs within California.

PG&E's vision of the future electric grid is a secure, resilient, reliable, and affordable platform that enables continued gains for clean-energy technologies and California's economy in a way that provides maximum flexibility and value for customers. However, while DERs help achieve California's clean energy objectives, they can potentially create new challenges including capacity (thermal) constraints, power quality issues (inclusive of voltage violations), and adverse impacts on protection systems due to bidirectional power flow[1,2]. Furthermore, hosting capacity (e.g. available grid capacity to safely and reliably interconnect additional DERs) is decreasing, thus reducing the overall flexibility of the grid to handle more DERs without infrastructure improvements.

Significant grid modernization investments are required to operate in this new paradigm while achieving the state's ambitious clean energy goals. To address these issues, PG&E is developing an Integrated Grid Platform (IGP) that improves situational awareness, operational efficiency, and enhances cybersecurity to meet today's challenges while positioning PG&E to meet the demands of a dynamic energy future. This platform will provide the required tools and capabilities to maintain grid safety, reliability, and affordability through efficient grid management. It will develop foundational systems to enhance situational awareness, modeling, forecasting, and visibility, from which more advanced applications like DERMS can be built to safely address both DER and non-DER related grid issues by coordinating, optimizing, and dispatching assets cost-efficiently.

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[1] Emerging Issues and Challenges in Integrating Solar with the Distribution System: https://www.nrel.gov/docs/fy16osti/65331.pdf
[2] High-Penetration PV Integration Handbook for Distribution Engineers: https://www.nrel.gov/docs/fy16osti/63114.pdf

A DERMS, combined with a system of new grid management tools including advanced Supervisory Control and Data Acquisition (SCADA) and Advanced Distribution Management Systems (ADMS), will enable the utility to leverage DERs for grid and local reliability benefits, realize value from DERs, and potential distribution investment deferral. However, the functionality of a DERMS is still evolving, and the technology is not readily available to comprehensively address utility requirements. PG&E's proposed IGP investments in the near-term focus on building foundational technologies including ADMS to support optionality for evolving future DERMS functionality and market needs (Figure 1).

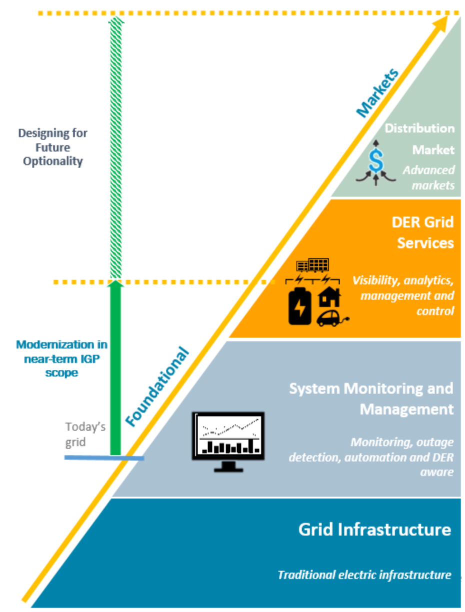

Figure 1: PG&E's IGP and Grid Modernization Approach

1.2 DERMS Demonstration System Overview

The PG&E EPIC 2.02 DERMS project (hereafter referred to as the "DERMS Demo") provided an opportunity for PG&E to define and deploy a proof of concept DERMS software and supporting operational technology to uncover barriers and specify requirements to prepare for the increasing challenges and opportunities of integrating and deriving value from DERs at scale. The DERMS Demo was an industry leading field demonstration of optimized control of a portfolio of 3rd party aggregated behind-the-meter (BTM) solar and energy storage and utility front-of-the-meter (FTM) energy storage. These assets provided distribution capacity and voltage support services while also allowing for participation of these same DERs in the CAISO wholesale market (Figure 2) to test DER value stacking, often referred to as multiple use applications (MUA)[3].

[3] MUA testing was limited in scope and used one type of DER technology (advanced energy storage)

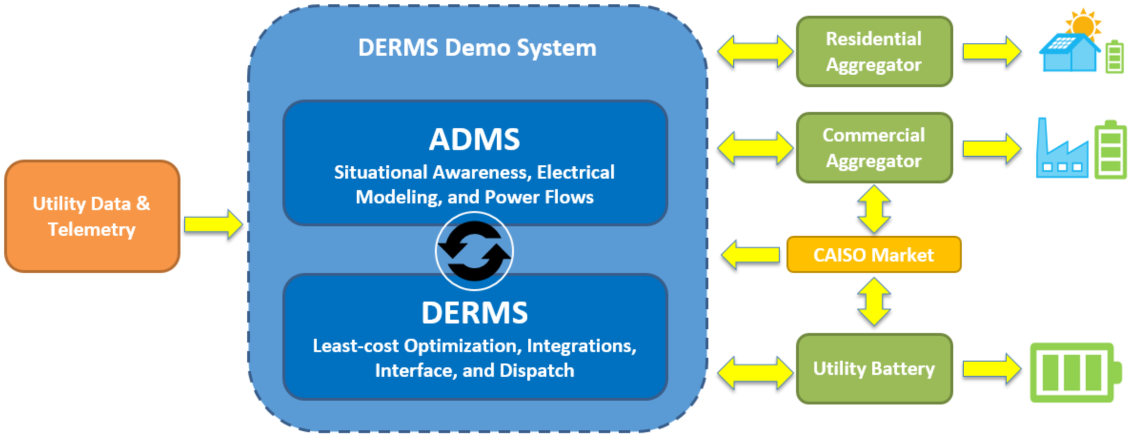

Figure 2: Simplified DERMS Demo Overview

Together with collaborating partners, PG&E deployed new systems and functionality that were either developed from scratch, or by integrating disparate technologies to achieve the project's desired objectives. The DERMS demonstration was co-located on feeders in San Jose with two other related projects (EPIC 2.03A – Test Smart Inverter Enhanced Capabilities – Photovoltaics (PV), and EPIC 2.19 – Enable Distributed Demand-Side Strategies & Technologies), to efficiently use EPIC funds and build collective learnings. The ambiguity of the market, complexity of modeling and calculations, and lack of standards and regulations made this project critical to begin developing learnings for a very uncertain future. While this project was a strong first step, additional investment is needed for both pre-commercial demonstration and a scaled production system, when ready. The learnings and recommendations from this project were critical in defining, implementing, and managing near-term DER solutions via the 2020 and 2023 General Rate Case (GRC) filing, candidate distribution investment deferral projects, and upcoming research and demonstration projects.

The main enablers and capabilities of the DERMS Demo can be summarized into three categories which build progressively upon one another:

1. ***Enhanced Situational Awareness*** is foundational in order to safely and reliably manage the grid with high penetrations of DERs and is a prerequisite for realizing additional distribution level value streams from DERs. As the grid becomes more complex with the proliferation of DERs, advanced tools are required to provide Distribution Operators the visibility, modeling, and forecasting capabilities required to operate the grid safely and efficiently. New situational awareness capabilities can identify the grid impacts from DERs and also dynamically identify real-time and forecasted grid constraints (e.g. capacity, voltage, etc.) to be mitigated by Distribution Operators.

   PG&E deployed a scaled-down ADMS on the demonstration feeders to provide the enhanced situational awareness capabilities required to enable a DERMS. Because PG&E does not currently have an ADMS, this deployment helped identify requirements, characterize gaps, and provide implementation lessons learned for an ADMS at scale.

2. ***Distribution Services*** describe the ability for DERs to mitigate an existing or forecasted grid need as a "least cost-best fit" option when compared to more traditional utility controls or investments. The four key distribution grid services are distribution capacity, voltage support, reliability (back-tie capacity), and resiliency (microgrids) [4].

   This project leveraged the ADMS to identify grid needs and DER impacts from which the DERMS determined the optimal dispatch of active and reactive power to provide voltage and capacity services. A combination of DER constraints[5] as well as active management were used to manage DER outputs through either real-time or scheduled controls. Availability, flexibility, and dispatches of aggregated DERs were communicated through implementation of a novel IEEE 2030.5[6] Utility-to-Aggregator Interface with custom extensions.

3. ***Economic Optimization*** describes how DER dispatches should be co-optimized based on financial factors and physical grid needs. This is the least defined part of a DERMS and has significant dependencies on the advancement of new programs, policies, and regulations.

   The DERMS Demo did not attempt to determine the underlying value of distribution services, nor did it specify how distribution services should be enabled as these are being explored separately through the Distribution Resources Plan (DRP) and Integrated Distributed Energy Resources (IDER) Proceedings. However, to explore existing challenges that need to be considered for policy, regulations, and future projects, the DERMS Demo implemented a simulated distribution market construct and dispatched DERs based on a least-cost optimization for grid services and energy arbitrage. Interactions with the participating DERs were orchestrated through a day-ahead ask-bid-commit market and a real-time ad-hoc market for distribution services coordinated with existing programs through a limited subset of MUA test scenarios.

The DERMS Demo successfully demonstrated the potential of this technology and identified immediate next steps in deploying foundational utility capabilities, key barriers to scale, and future research and development opportunities related to incorporating DERs into utility operations.

[4] D.16-12-036 Decision Addressing Competitive Solicitation Framework and Utility Regulatory Incentive Pilot: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M171/K555/171555623.PDF

[5] DER constraints for the DERMS Demo refer to hourly limits on active power output for both generation and load

[6] At the time of EPIC 2.02 DERMS implementation, IEEE 2030.5-2013 was the most recent standard, which has since been superseded by IEEE 2030.5-2018 – IEEE Approved Draft Standard for Smart Energy Profile Application Protocol: https://standards.ieee.org/standard/2030_5-2018.html

1.3 Key Objectives & Accomplishments

The main objective of the DERMS Demo was to test and demonstrate that new technologies can provide the functionality to monitor and control DERs to manage system constraints and evaluate the potential value of DER flexibility to the grid. The DERMS Demo demonstrated that value from DERs to provide grid services could be realized. This demonstration drove learnings about the people, process, and technology needed to operate the high DER penetration grid of the future. The challenges and lessons learned through this implementation helped move the industry and PG&E forward in the DERMS space, while grounding perspectives of near-term versus future needs and capabilities.

The following summarizes the DERMS Demo key objectives and related accomplishments:

Objective 1: Define DERMS Product Requirements and Characterize PG&E DERMS Needs
Accomplishments:
- Worked with DER providers, vendors, and industry leaders to create, test, and iterate on DERMS requirements and architecture
- Defined strategy for DER-Aware ADMS functionality as a foundation for a future DERMS

Objective 2: Define Boundaries and Integrations with Internal and External Systems
Accomplishments:
- Defined functionality boundaries and integrations between DERMS and ADMS
- Exchanged grid services between the utility and 3rd party DER aggregators through a customized IEEE 2030.5 aggregator interface
- Incorporated DER wholesale participation into distribution forecasts and optimization
- Tested a subset of MUA use cases through coordination with customer sited demand charge management, distribution services, and CAISO wholesale markets. Utility storage participated in the energy and frequency regulation wholesale markets, while 3rd party storage participated in simulated DR markets[7].

Objective 3: Demonstrate Technical Feasibility of Utilizing DERMS to Manage DERs for Distribution Grid Services
Accomplishments:
- Provided enhanced situational awareness (via ADMS) and DER distribution services (via DERMS) under normal and abnormal switching conditions
- Mitigated real-time and forecasted voltage and capacity constraints using active and reactive power of the available DERs

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[7] To mimic wholesale market participation, 3rd party storage was aggregated into a single DER resource and bid into a simulated market as a Proxy Demand Resource (PDR) via PG&E's Supply Side II DR Pilot (SSP II), with additional load increase dispatches based on PG&E's Excess Supply DR Pilot (XSP). The utility battery generally participates in the wholesale ancillary services market as a FTM resource using CAISO's non-generating resource model.

- Managed a 3rd party aggregated fleet of 124kW residential solar, 66kW/4-hr residential storage, 360kW/2-hr commercial storage, and 4MW/7-hr utility storage

Objective 4: Implement and Evaluate Economic Optimizations and Market Mechanisms for DER-Provided Distribution Services
Accomplishments:
- Demonstrated the capabilities of a least-cost dispatch to efficiently dispatch DERs to mitigate system issues, or provide energy arbitrage
- Implemented an automated market via an IEEE 2030.5 Aggregator Interface that enabled a day-ahead ask-bid-commit and hourly ad-hoc market for distribution services
- Evaluated and documented potential barriers of implementing distribution markets in the near-term, including the challenges of instituting MUA of DERs

Objective 5: Perform DERMS Deployment Readiness Assessment & Create Deployment Strategy
Accomplishments:
- Identified challenges associated with existing systems, data, and telemetry at PG&E to enable a DERMS
- Implementing DER-Aware ADMS and DERMS strategy through PG&E's IGP Program and the 2020 and 2023 GRC filing
- Learned about business process change and personnel skills and knowledge needed to implement DERMS

1.4 Key Takeaways

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

- **A comprehensive DERMS is still not readily available.**

  PG&E determined it is still too early to invest in a comprehensive DERMS based on the experience through this demonstration, the expected near-term impacts of DERs on the system, and the state of the industry. While DERMS vendors exhibited capabilities in certain aspects of a DERMS, there was no vendor capable of the comprehensive DERMS system PG&E envisions at this time. The interplay of rules, regulations, and policies also have a profound impact on the definition of DERMS and associated requirements, and need to be reviewed as they evolve. Continued investment via EPIC is necessary to provide the opportunity to push the industry forward through further research and development.

- **PG&E needs to invest in foundational technology including improved data quality, modeling, forecasting, communications, cybersecurity, and a DER-aware ADMS to address the near-term impacts of DERs and grid complexity while providing the groundwork for a future DERMS system.**

PG&E currently lacks the foundational technology not only to enable a DERMS but also to provide modeling and situational awareness capabilities that are needed to operate an increasingly complex grid. The project had to install an ADMS and resolve multiple data quality and utility equipment field telemetry issues just to enable DERMS.

- **A DERMS paired with an ADMS can identify and mitigate real-time and forecasted distribution capacity and voltage issues using a combination of DER constraints with active and reactive power dispatches.**

  This project successfully showed that DERs can be used to mitigate real-time and forecasted issues on the distribution system through constraints and active management:
  - *Constraints* proved to be an effective method to ensure DERs are good citizens of the distribution grid by preventing their creation of capacity and voltage issues while allowing them flexibility to operate in any given market.
  - *Active dispatch* provides a mechanism to go beyond being a good citizen of the grid by enabling DERs to realize value through mitigating grid needs caused by others.

  The impacts of active power and reactive power will vary depending on circuit and locational characteristics of DER installations. Reactive power had more of an impact than active power in certain situations on the demonstration feeders, with the added benefit of minimally impacting storage state of charge or active power dispatches in other markets.

- **DERs must provide sufficient locational value, volume, availability, and dispatch assurance to offer grid services.**

  The ability for DERs to resolve a particular grid need will vary based on circuit characteristics, location, and the ability to acquire enough DERs to participate in providing distribution services. Additionally, these resources must be readily available to respond with a comparable level of certainty as traditional utility infrastructure.

  While the project technically showed the potential of a DERMS, the actual amount of mitigation at medium voltage levels, specifically 21kV for this project, provided by non-utility scale DERs was relatively small based on the available DERs to resolve any particular grid issue. This was especially true for voltage mitigation.

- **Targeted DER acquisition can be challenging, and significant location specific penetrations are needed to resolve distribution issues.**

  Through the EPIC 2.02, 2.03A, and 2.19 projects, PG&E and the DER vendors discovered that targeted customer recruitment for DER services was more challenging than expected, even with substantial incentives for customer adoption. 3rd party financing of many DERs can also affect their ability and willingness to participate in certain programs. Organic growth of dispatchable DERs at the scale required to create a meaningful impact where needed is a challenge in the near-term. Targeted grid services projects in the future must consider the difficulties of timely acquisition and deployment of willing DER customers.

- **Large highly variable DERs participating in wholesale frequency regulation markets are difficult to forecast and incorporate into distribution calculations**

  Special capabilities in software and high sampling field measurement equipment were developed to incorporate worst-case loading into forecasts and to ensure power flow calculation convergence in the presence of large highly variable frequency regulation dispatches.

- **Unified standards, protocols, testing, and exchanges are needed as DERMS requirements and market structures become more defined.**

  Due to the nascent state of the industry, comprehensive standards and regulations do not yet exist. PG&E attempted to use existing standards to the extent possible, but many were insufficient, requiring custom extensions or additional verifications.

  In addition, the DERMS Demo showed vendors may interpret existing standards differently, indicating the need for common understandings of concepts like flexibility, operating responses, and rules of operation.

- **MUA requires transparency, coordination, and rules across programs to ensure proper prioritization and equitable settlement.**

  While the DERMS Demo did not address all the issues around MUA, it made clear that without transparency, coordination, and rules across programs and contracts, it can create confusion, settlement issues, and potential safety concerns. There continues to be substantial efforts to address these and other challenges in industry working groups such as the CPUC's Energy Storage MUA Working Group.

- **To preserve distribution safety and reliability, distribution dispatch must have priority over wholesale market operations and visibility across both systems.**

  As more distribution assets participate in the wholesale market, Distribution Operators need to be aware of the potential impacts on distribution system conditions. While wholesale energy pricing should provide beneficial load shifting for the vast majority of feeders, there may be instances where distribution needs and wholesale signals conflict due to abnormal switching, atypical feeder load shapes, or ancillary services. To account for these edge cases and in order to avoid creating safety or reliability issues on the distribution system, it is recommended that when conflict can reasonably be anticipated in the short term, distribution needs and/or constraints have priority over wholesale signals. While conflict can be anticipated and planned for through capacity planning and interconnection processes, dynamic management of conflict may provide a more efficient method of enabling hosting capacity than static constraints and infrastructure investments. Flexibility should be built-in to potentially operate under "emergency ratings" on distribution if extreme transmission situations require it.

1.5 Recommendations

The following recommendations are applicable both industry-wide and to PG&E specifically:

Invest in foundational technology: Investments in improved data quality, modeling, forecasting, communications, and a DER-aware ADMS are required to achieve any efficient dispatch of DERs in the future. Regardless of future policy or market trends, Distribution Operations will need these tools to safely and reliably operate the grid as complexity increases with the continued growth of DERs. The learnings and requirements gathered through the DERMS Demo helped develop PG&E's IGP strategy and requirements for a DER-aware ADMS for the 2020 and 2023 GRC filing, and proposed projects for EPIC 3.

Distribution services provided by DERs must be coordinated with existing utility mechanisms for capacity and voltage issue mitigation: DERMS is a tool for managing the grid in concert with traditional utility grid management tools. In some instances, it may be more efficient and cost competitive to use traditional grid infrastructure investments, manual/automated settings changes, circuit reconfigurations, or existing field devices to maintain grid safety, reliability, and compliance. Therefore, DERMS must be able to coordinate with these other systems in real-time to ensure cost-effectiveness as well as making sure they work together and do not oppose or undermine one another.

Develop methods to ensure DERs provide sufficient availability and dispatch assurances to offer grid services: Distribution Operators have historically been the owners, maintainers, and operators of the equipment and systems assuring grid safety, reliability and compliance. To use 3rd party DERs to provide distribution grid support functions, it is critical that structures, rules, contracts, and failsafes are created to ensure that the safety, reliability, and compliance of the grid are not compromised by reliance on 3rd party systems. Solutions for these challenges will be explored by PG&E through EPIC 3, demand response pilots, and candidate distribution investment deferral projects.

Enable DERMS capabilities on an as-needed basis at constrained distribution locations: Optimization technologies, control systems, regulations, and standards for incorporating wholesale transmission and distribution pricing signals into DER operations may be expected to evolve significantly, and to decrease in costs for both software and hardware over the next decade. Without the widespread need for DER distribution services at this time, targeted solutions would provide an opportunity to fill existing gaps in the absence of clear regulations or policy and develop critical DERMS functionalities. Targeted deployment would also help prevent unjustified spending on a system-wide DERMS when there may not be a system-wide need.

Bilateral market contracts and targeted customer programs may be the most efficient transaction mechanism for distribution services in the near-term: The investments needed to support a dynamic market for services on a system as large and dispersed as PG&E's distribution system will be significant. While this may be required in the long-term, to ensure affordability for customers, it would not be prudent to prematurely scale complex markets system-wide. Competitively sourced bilateral market contracts and targeted customer programs in the near-term may provide a method to overcome ambiguity in the distribution market space to more readily enable DERs to provide distributions services where needed.

Advance maturity of standards, policies, and regulations: PG&E and industry leaders should continue to be engaged in the various standards, policy, and regulatory bodies that are shaping the industry. EPIC and other research and development initiatives around the country have helped push the conversation forward, but more investment is needed to help grow this evolving industry. Continued involvement in forums like EPIC, IEEE, CPUC Proceedings, or the MUA Working Group are necessary to shape technology and drive alignment between regulators, utilities, vendors, and customers.

An ADMS should be the source of power system situational awareness, and provide power system calculations, grouping, and other information to an integrated DERMS: Demonstrating an ADMS integrated with a DERMS clarified what types of functions naturally reside in each system. PG&E considers a DER-aware ADMS as managing power system related parameters and potentially larger connected DERs. A DERMS builds on that foundation by layering on and incorporating more non-electrical considerations to optimize dispatch of DER assets regardless of size. Non-electrical information allows a DERMS to enhance baseline electrical groupings or optimizations based on pertinent economic, customer, or program specific information. Additionally, the ADMS does not need to directly communicate with all DERs. DERMS is expected to be the platform that reaches out to the majority of DERs either through aggregators or direct connections.

While tight integration is required (DERMS could even be an offering from an ADMS vendor), separating these functions reduces the complexity of maintaining redundant models and databases. Additionally, the ADMS is used for the day to day operations of the grid; and having a separate DERMS reduces the burden on the ADMS and allows for greater flexibility to evolve as conditions become more defined. PG&E is pursuing this vision of a DER-Aware ADMS through the 2020 and 2023 GRC filing.

1.6 Conclusion

The DERMS Demo successfully demonstrated the potential of DERMS technology, while creating key learnings that helped further the industry and identify ADMS and DERMS needs for PG&E. The project successfully leveraged 3rd party aggregated and utility DERs to provide distribution services via an automated market structure while testing aspects of MUA. Through collaboration with the participating vendors, other PG&E demonstrations, and industry leaders, the DERMS Demo progressed the state of the industry. It also allowed PG&E to define near-term and long-term ADMS and DERMS needs while establishing a cost-competitive DER strategy.

Outstanding policy, regulatory, and program ambiguity make it imprudent to implement a full-scale DERMS immediately. However, results of this project provide clear next steps PG&E and the industry can take towards fulfilling near-term needs operating a more complex grid, while building foundational functionality that can be used to enable future grid services. Using the lessons learned through this demonstration, PG&E is pursuing these technology investments through the Integrated Grid Platform Program as part of the 2020 and 2023 General Rate Case filing. PG&E is also proposing further DERMS exploration in EPIC 3, building upon the learnings of the DERMS Demo to develop and demonstrate more near-term DERMS related functionality

2 Introduction

This report documents the EPIC 2.02 DERMS project achievements, highlights key learnings from the project that have industry-wide value, and identifies future opportunities for PG&E and other statewide utilities and market actors to leverage this project.

The California Public Utilities Commission (CPUC) passed two decisions that established the basis for this demonstration program. The 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, the 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, 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 three-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 Electric Program Investment Charge (EPIC) Application with the CPUC, requesting $49,328,000 including funding for 26 Technology Demonstration and Deployment Projects. On November 14, 2013, in D.13-11-025, the CPUC approved PG&E's EPIC plan, including $49,328,000 for this program category. On May 1, 2014, PG&E filed its second triennial investment plan for the period of 2015-2017 in the EPIC 2 Application (A.14-05-003). CPUC approved this plan in D.15-04-020 on April 15, 2015, including $51,080,200 for 31 TD&D projects.[12]

Pursuant to PG&E's approved 2015-2017 EPIC triennial plan, PG&E initiated, planned and implemented the following project: EPIC 2.02 - DERMS. Through the annual reporting process, PG&E kept CPUC staff

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[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 pg. 37
[11] Pacific Gas & Electric (PG&E), San Diego Gas & Electric (SDG&E), Southern California Edison (SCE), and the California Energy Commission (CEC)
[12] In the EPIC 2 Plan Application (A.14-05-003), PG&E originally proposed 30 projects. Per CPUC D.15-04-020 to include an assessment of the use and impact of electric vehicle energy flow capabilities, Project 2.03 was split into two projects, resulting in a total of 31 projects.

and stakeholder informed on the progress of the project. The following is PG&E's final report on this project.

2.1 Project Motivation

California is a leader in the growth of DERs driven by a confluence of technology advancements, consumer preferences, and complementary legislative and regulatory actions. California's Renewable Portfolio Standard (RPS) and SB-100 (33% renewable by 2020, 60% renewable by 2030, and 100% zero-carbon by 2045[13]), net energy metering (NEM) policies, and federal tax subsidies have propelled EV and solar adoption within the PG&E territory. As of November 2018, there are more than 200,000 EV registrations, and over 5,000 solar installations added each month totaling more than 390,000 sites. To further support this growth in renewables, California State Assembly Bills (AB) 2514[14] and AB 2868[15] are requiring large investments in energy storage technology to help create a more flexible grid to enable less traditional forms of generation.

However, while DERs help achieve California's clean energy objectives, they can potentially create new challenges including capacity (thermal) constraints, power quality issues, inclusive of voltage violations, and adverse impacts on protection systems due to bidirectional power flow. Furthermore, hosting capacity is decreasing, thus reducing the overall flexibility of the grid to handle more DERs without infrastructure improvements

Systems such as DERMS are needed to not only manage the additional complexity created by DER growth, but to leverage DERs for grid and local reliability benefits, realize value from DERs, and potential distribution investment deferral. Significant grid modernization investments are required to operate in this new paradigm while achieving the state's ambitious clean energy goals. PG&E's vision of the future electric grid is a secure, resilient, reliable, and affordable platform that enables continued gains for clean energy technologies and California's economy in a way that provides maximum

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[13] Senate Bill No. 100 (SB-100):
https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180SB100

[14] AB 2514 was designed to encourage California to procure by 2020 and incorporate by 2024 energy storage into the electricity grid 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.

[15] 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.

flexibility and value for customers. This will require the coordination of new and existing tools and infrastructure including advanced applications such as DERMS.

2.2 Trends in the Industry

As an emerging technology, the definition of DERMS capabilities is still evolving. In general, a DERMS can manage a variety of both aggregated and individual DERs to support various objective functions related to grid support, customer value, or market participation[16]. This may be accomplished through software only, or a combination of software and hardware.

Utility DERMS capabilities and needs vary widely: existing DER impacts, infrastructure, and regulatory landscapes can all affect individual utility needs. As a result, vendor offerings are non-standard. Architectures and approaches range between centralized and distributed systems, and capabilities are not always clearly separated among DERMS or its supporting systems.

The interaction with 3rd party DERs is also evolving along with the growth of cloud services and other non-traditional Supervisory Control and Data Acquisition (SCADA) communication paths, creating new challenges for utilities regarding cybersecurity and reliability.

DERMS has significantly evolved since the beginning of this program. When the DERMS Demo RFP was released in 2015, a stand-alone DERMS that met the basic needs of PG&E was virtually unheard of from traditional utility vendors. While some DERMS-like functionality existed in various forms from various vendors, the offerings were non-uniform and immature.

The DERMS Demo was designed to help advance the industry, define product requirements, and characterize PG&E's future DERMS needs to safely manage grid-connected DERs. The demonstration focused on situational awareness and capacity and voltage violation mitigation on the as-operated grid. Last, the team implemented market frameworks as a mechanism to explore existing challenges that need to be considered for future policy, regulatory forums, and projects.

In 2015, the PG&E team participated in early-stage working groups to better define DERMS capabilities and related processes. The industry has since matured; multiple recent activities and publications have sought to standardize definitions and understand the required capabilities of a utility DERMS[17].

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[16] Mulherkar, A. 2017. North American DER Management Systems 2017-2021. Boston: GTM Research.

[17] The following list describes some recent industry work around DERMS:

- Electric Power Research Institute (EPRI) whitepaper "Understanding DERMS" https://www.epri.com/#/pages/product/000000003002013049/?lang=en
- Greentech Media (GTM) Research report "North American DER Management Systems 2017 – 2021" https://www.greentechmedia.com (subscription required)

3 Project Summary

The DERMS Demo was focused on creating clarity around DERMS capabilities for PG&E to ensure prudent future investments by navigating the nascency of the market and determining near- and long-term needs. The learnings and recommendations from this project are critical in supporting the definition, implementation, and management of near-term DER solutions in many forums, including: the IGP, 2020 and 2023 GRC filing, candidate distribution investment deferral projects, and upcoming research and demonstration projects.

3.1 Issues Addressed

The DERMS Demo was developed to address issues regarding the growth of DERs, their impacts on grid complexity, and the ability to realize both grid and customer benefits from DERs. Due to the nascency of the industry and the ambiguity surrounding DERMS, the project was designed to identify requirements and prove technical feasibility of a DERMS and supporting infrastructure by demonstrating 3 progressive core functionalities that underpin a DERMS:

1. Enhanced Situational Awareness (Section 3.1.1)
2. Distribution Services (Section 3.1.2)
3. Economic Optimization (Section 3.1.3)

The demonstration learnings and results of each of these items are addressed in sections 6, 7, and 8, respectively.

3.1.1 Enhanced Situational Awareness

Enhanced situational awareness is foundational in order to safely and reliably manage a grid with high penetrations of DERs. Further, it is a prerequisite for realizing potential additional distribution level value streams from DERs. As the grid becomes more complex with the proliferation of DERs, advanced tools are required to provide Distribution Operators the visibility, modeling, and forecasting capabilities required to operate the grid safely and efficiently. New situational awareness capabilities can identify the grid impacts from DERs and also dynamically identify real-time and forecasted grid constraints (e.g. capacity, voltage, etc.) which Distribution Operators can mitigate.

The ability to incorporate the impacts of DERs into traditional situational awareness capabilities (e.g. SCADA, DMS) is an existing gap for Distribution Operations at PG&E, and many other utilities. Through

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- EPRI released a major rewrite to "Common Functions for DER Group Management, Third Edition" https://publicdownload.epri.com/PublicDownload.svc/product=000000003002008215/type=Product
- Smart Electric Power Alliance (SEPA) released a standardized requirements document focused on DERMS for comment https://sepapower.org/derms-requirements/
- Regulatory and Standards work including Electric Rule 21, IEEE 1547, IEEE 2030.5, IEEE 2030.11

the DERMS Demo, PG&E determined that a DER-aware ADMS is the logical provider for enhanced electrical situational awareness capabilities that would supply the necessary information to an integrated DERMS. As an ADMS is already the system of record for the as-operated grid, this would provide foundational capabilities for Distribution Operations, and avoid duplicating and maintaining separate and redundant models in a DERMS. A DER-aware ADMS can provide the electrical information to a DERMS, from which a DERMS can then layer program and economic optimizations to best manage DERs.

PG&E deployed a scaled-down ADMS on the demonstration feeders to provide the enhanced situational awareness capabilities required to enable a DERMS. Because PG&E does not currently have an ADMS, this deployment helped identify requirements, characterize gaps, and provide implementation lessons learned for an ADMS at scale.

Enhanced situational awareness is needed regardless of there being a fully implemented DERMS. The technical capabilities provided by a DER-aware ADMS underpin the safe inclusion of DERs regardless of the uncertainty in policy, regulations, or market structures. Learnings from this project directly informed the request for a DER-aware ADMS in the IGP Program included in PG&E's 2020 and 2023 GRC filing. This will help address the foundational needs to operate a more complex grid in the near-term while enabling future DER functionality.

3.1.2 Distribution Services

Distribution services describe the ability for DERs to mitigate an existing or forecasted grid need as a "least cost-best fit" option in partnership with more traditional utility controls or investments. While inverter autonomous functions like Volt/VAR in Electric Rule 21[18] help reduce the negative impacts of DERs at the point of interconnection, they neither provide system level coordination nor the opportunity for DERs to realize additional value. Therefore, additional systems are required to provide the comprehensive visibility and coordination to address distribution grid services while providing a platform for DERs to potentially realize value. The four key distribution grid services are distribution capacity, voltage support, reliability (back-tie capacity), and resiliency (microgrids). The DERMS Demo focused primarily on distribution capacity and voltage support services.

DERMS enabled distribution services respond to the grid needs and DER impact assessments provided by the ADMS situational awareness capabilities. The ADMS calculated the grid needs and quantified the support specific DERs could provide to resolve a particular problem (See Section 13 – Appendix A regarding Volt/kW, Volt/kVAR, Amp/kW sensitivities). The DERMS used this information, coupled with aggregator information, to determine optimal dispatch of active and reactive power for distribution

[18] California's Electric Rule 21 is a tariff that describes the interconnection, operating, and metering requirements for utility distribution connected generation facilities: http://www.cpuc.ca.gov/Rule21/

services through a least-cost optimization. A combination of DER constraints as well as active management were used to manage DER outputs through either real-time or scheduled controls. Availability, flexibility, and dispatches of aggregated DERs were communicated through implementation of a novel IEEE 2030.5 Utility-to-Aggregator Interface with custom extensions.

A combination of constraints and active management proved effective in enabling DERs to realize value outside of distribution services, while allowing them to be good citizens of the grid. Dynamic constraints allow DERs to act freely within adjustable prescribed guardrails without negatively impacting the grid, and enable more DERs to operate under strained grid conditions during interconnection or abnormal conditions. Active management could provide a means to go beyond just being a good citizen of the grid to potentially mitigate grid needs as an additional value stream.

PG&E plans to continue research started in the DERMS Demo to explore capabilities to provide limited constraints as a potential path to overcome the limitations of traditional hosting capacity and more efficiently enable more DERs while reducing costly infrastructure investments. In addition, learnings from this demonstration will be incorporated into potential candidate distribution investment deferral projects in the near future.

3.1.3 Economic Optimization

Economic optimization describes how DER dispatches should be co-optimized based on financial factors and physical grid needs. This is the least defined part of a DERMS and has significant dependencies on the advancement of new programs, policies, and regulations.

The DERMS Demo did not attempt to determine the underlying value of distribution services, nor did it specify how distribution services should be enabled as these are being explored separately through the Distribution Resources Plan (DRP) and Integrated Distributed Energy Resources (IDER) Proceedings. However, to explore existing challenges that need to be considered for policy, regulations, and future projects, the DERMS Demo implemented a simulated distribution market construct and dispatched DERs based on a least-cost optimization for grid services and energy arbitrage. Interactions with the participating DERs were orchestrated through a day-ahead ask-bid-commit market and a real-time ad-hoc market for distribution services coordinated with existing programs through a limited subset of MUA test scenarios.

The DERMS Demo demonstrated the significant complexity and challenges implementing a new market and coordinating it with existing markets and programs. Continued participation with the CPUC and industry through various forums such as the Energy Storage Proceeding's MUA Working Group, will help provide more clarity around economic structures and mechanisms to enable DERs at scale. In the near-term, bilateral contracts, targeted customer programs, and targeted DERMS may be the most efficient method to enable DER provided distribution services and ensure DERs do not create adverse effects on the grid.

3.2 Project Objectives

To address the issues outlined above, the DERMS Demo met the following objectives by collaborating across the energy industry, bringing together the utility, 3rd party aggregators / developers, and software vendors to implement a novel demonstration that pushed the state of the industry forward. PG&E chose to implement a minimum viable product (MVP) for the DERMS Demo based on the ambiguity of the market, complexity of modeling and calculations, and lack of standards and regulations.

Objective 1: Define DERMS Product Requirements and Characterize PG&E DERMS Needs

- Create, test and iterate on PG&E DERMS requirements
- Characterize the future system architecture for DERMS and DERMS enabling functionalities, including the ADMS

Objective 2: Define Boundaries and Integrations with Internal and External Systems

- Define boundaries and integrations with other PG&E and external systems such as Demand Response, Aggregators, ADMS, and CAISO market systems.

Objective 3: Demonstrate Technical Feasibility of Utilizing DERMS to Manage DERs for Distribution Grid Services

- Demonstrate real-time enhanced situational awareness and short-term forecasting
- Mitigate real-time and forecasted capacity constraints using active power of the available DERs
- Mitigate real-time and forecasted voltage constraints using active and reactive power of the available DERs
- Provide enhanced situational awareness and DER distribution services under abnormal switching conditions
- Evaluate the performance of aggregated DERs providing distribution services

Objective 4: Implement and Evaluate Economic Optimizations and Market Mechanisms for DER-Provided Distribution Services

- Demonstrate and evaluate the use of a least-cost dispatch method for grid services or energy arbitrage
- Implement and evaluate day-ahead ask-bid-commit and hourly ad-hoc market mechanisms to facilitate transactions between DERs and the distribution utility
- Demonstrate and evaluate MUA of DERs providing services to customer, distribution, and wholesale domains

Objective 5: Determine DERMS Deployment Readiness Assessment & Strategy

- Identify limitations of existing as-built models and field telemetry data
- Identify barriers to future deployment at scale

- Learn about business process change and personnel skills and knowledge needed to implement DERMS
- Enable informed choice for future vendor selection for DERMS or DERMS foundational functionality (e.g. ADMS)

3.3 Scope of Work and Project Tasks

To accomplish the objectives for EPIC 2.02 DERMS, the following key items were in scope:

- Test the abilities of DERMS operation at PG&E through a minimum viable product field demonstration to address key DER management use cases:
    - Provide DER-Aware Situational Awareness
    - Manage Equipment Capacity Constraints and Reverse Power Flow through DER Dispatch
    - Mitigate Voltage Issues with DER Active Power Dispatch
    - Mitigate Voltage Issues with DER Reactive Power Dispatch
    - Provide DER Management Functionality Under Abnormal Topology Conditions
    - Economic Dispatch of Distributed Solar Generation and Energy Storage
    - MUA for BTM and FTM DERs
- Demonstrate the ability to monitor and control a diverse set of aggregated 3rd party and utility owned DERs in a limited geography
- Create, test, and iterate on future DERMS requirements to inform near-term and long-term DER strategy and future vendor selection

3.3.1 Tasks and Milestones

Table 1 below includes the tasks and milestones that were achieved by the project:

Table 1: Description of Major Project Activities

Activity	Description	Date Achieved
Planning Phase: Identify specific Use Case objectives, demonstration location, DERMS system vendor, and core technical requirements for the system. Define the project plan in sufficient detail to indicate feasibility of successful completion of project goals. Identify gaps, risks and create mitigation plan, and develop detailed implementation budget and schedule		
Use Case Definition	Define the scope of the project in terms of specific grid management Use Cases to be demonstrated.	September 2015
Geography Selection	Selection of circuits in San Jose and decision to combine EPIC 2.02, 2.03A, and 2.19 in coordinating DER assets across projects.	December 2015
Industry Benchmarking	Review utility DERMS implementations in the US and internationally via desk research and interviews with other utilities and software vendors	December 2015

Activity	Description	Date Achieved
DERMS Vendor RFP	Selection of a system vendor after competitive solicitation.	December 2015
Detailed Technical Requirements	Develop rigorous list of technical requirements for the demonstration system to meet in order to fulfill the project Use Cases.	June 2016
System Model Validation	Refine the quality and completeness of the utility data on the selected circuit geography to a sufficient level to be used by the DERMS system for the Use Cases	June 2016
DER Asset Vendor RFP	Selection of vendors for targeted deployment of DER assets on the selected circuit geography to integrate with control by the DERMS system for the demonstration	June 2016
Design Phase: Detailed software solution and IT architectural design for the DERMS system. Creation of test plan for each Use Case to be demonstrated. Definition and implementation of a customer acquisition plan including marketing approach.		
DERMS System Design	Creation of system architecture and software design of the DERMS application and supporting infrastructure	August 2016
Customer Acquisition and DER deployment	Identify a marketing plan for identifying and soliciting sales of vendor's DER offerings to host customer sites. Three proceeding waves of outreach supported by PG&E and vendors to reach potential DER customers, followed by permitting, construction, interconnection and asset commissioning	Rolling deployment: November 2016 – October 2017
Aggregator Interface Design	Coordinate between DERMS vendor and DER vendors to define technical requirements for the software and communications interface between individual devices and the centralized DERMS system	December 2016
Build & Test Phase: Constructing the DERMS software, support systems, and communications channels to reach end devices. Deploy the DERs for the demo, and commission both the generation assets and the software interface between the vendor's aggregation platform and the DERMS system. Demonstration and data collection of the Use Cases.		
Build/Test the DERMS system, including Site Acceptance Testing	Baseline functionality included online power flow, situational awareness, and essential communications to aggregator interfaces. The ask-bid-commit and hourly ad-hoc build implemented the core economic dispatch methodology, and a subsequent build (MUA use case) created a means to incorporate the distribution Use Cases with	Baseline: February 2017 Ask-Bid-Commit: June 2017 MUA Use Case: January 2018

Activity	Description	Date Achieved
	CAISO market dispatches for connected DERs.	
Aggregator Interface Build & Site Acceptance Testing	Deployment of aggregator side interfaces with the DERMS system and commissioning of each additional DER as deployment proceeded.	September 2017
Field Demonstration	Complete execution of the test protocol defined in the prior stage to operate and measure the effectiveness of the solution for each Use Case	March 2018
Decommissioning	Decommission the DERMS system	September 2018
Project Closeout	**Synthesis of findings and Final Report. Includes communicating findings with relevant stakeholders internally and externally, as well as documentation and archival of project records, and other administrative activities.**	**December 2018**

4 Project Initiation and Enablement

4.1 Overview

At the start of the DERMS Demo in 2015, the nascency of the DERMS industry in terms of market offerings for DERMS solutions, lack of technology standardization, as well as the limited proven ability for energy storage and solar DERs to provide distribution services created considerable challenges. **DERMS vendor selection required specific methods to address deficiencies in the market to compare immature solutions where no vendor could demonstrate readily available DERMS functionality that met the needs of PG&E.**

In addition, the process for targeted DER customer acquisition to provide distribution services was found to be more challenging than expected. Challenges existed throughout the acquisition process from finding willing customers, through permitting and interconnection. The end result was a smaller than expected fleet of 3rd party DERs. However, the addition of a large utility battery provided the power for more measurable grid impacts, while still being able to demonstrate control across a variety of aggregated assets.

4.2 DERMS Vendor Selection

PG&E selected external partners for the DERMS Demo through a competitive sourcing process. The procurement process was split into an initial open Request for Proposal (RFP), which was released in August 2015, a supplemental questionnaire for finalist vendors that was released in early October 2015, and an in-depth in-person vendor demonstration of specific target use case scenarios (Section 24 – Appendix).

To address ambiguity and ensure cost-effective learning in an emerging market, PG&E decided to structure the project as a minimum viable product to determine near-term and long-term DERMS requirements rather than procuring a long-term DERMS for use beyond this project. In addition, the nascency of the industry drove PG&E to create and use a comprehensive Technology Capability Maturity model to evaluate the vendor solutions rather than a traditional requirements-based RFP. This model measured multiple dimensions of a DERMS across seven categories (Table 2). This helped gauge technology risk relative to the project goals and was well suited for evaluating nascent technology.

Table 2: DERMS Technology and Vendor Capability Maturity Model Categories

Category	Desired DERMS Capability
Optimization	Automatically optimize DER dispatch across engineering, economic, contractual, and regulatory parameters. Simultaneously process local and system-level optimizations.
Measurement, Analysis & Reconciliation	Core DERMS capabilities include the ability to measure device outputs and corresponding impacts, the analysis required for optimization, forecasting electrical and economic drivers, control of DER assets, and the reconciliation of events in the context of electrical, economic, and/or contractual obligations.
Life-Cycle Management	Manage the life-cycle of a DER asset within DERMS from registering assets, managing constraints, commissioning, asset health maintenance, and decommissioning.
Real-Time Situational Intelligence	Ability to receive static and dynamic state data from a large number of assets and seamlessly integrate this data with operations for analysis, reconciliation functions, state of health, and related visualizations.
Architecture	Maintain a DERMS architecture that ensures reliability, scalability, and flexibility to drive system integrations, a modern data platform, analytics, and visualizations.
Security	Manage cybersecurity risk to systems, assets, data, and capabilities.
Vendor Capability Maturity	The Vendor Capability Maturity model identifies key risk areas for vendors based on the perceived organizational capacity to deliver the proposed DERMS, the ability to leverage existing technology, and the amount of development and customization required.

The process confirmed the nascency of the market relative to PG&E requirements, with vendors requiring significant investment to either extend existing ADMS or DRMS platforms, or proposing more decentralized controls that did not meet the required objectives of the project. PG&E scored the vendors from 0 to 1 in the given categories. Figure 3 shows the results of that process, substantiating PG&E's perception of the market at the time being relatively deficient in desired DERMS functionality.

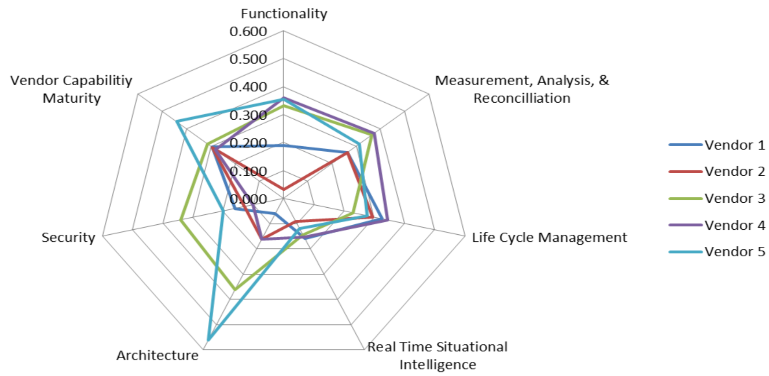

Figure 3: PG&E's Perception of the State of the DERMS Industry in Late 2015

Experience with the proposed use cases was an important factor for selection. It provided a base level of understanding and process from which to develop. The results of this scoring and evaluation helped PG&E choose a DERMS vendor that could provide the maximum amount of learning cost efficiently based on the existing technology for the demonstration.

4.3 Site Selection

There was an overarching goal to co-locate multiple EPIC projects to create efficiencies across efforts for customer acquisition, asset deployment, and platform integration to use EPIC dollars effectively. Therefore, site selection was based on criteria that would be beneficial to the three EPIC projects that had complimentary research aims and could share DER assets: EPIC 2.02 – DERMS, 2.03A – Test Smart Inverter Enhanced Capabilities – Photovoltaics (PV), and 2.19 – Enable Distributed Demand-Side Strategies & Technologies.[19] Table 3 describes some of the criteria and rationale used in the site selection process.

Table 3: Site Selection Criteria and Rationale

Criteria	Description	Rationale by EPIC Project
Distributed Solar Penetration	Behind the meter solar installed capacity as a fraction of net load at noon	**Smart Inverter, DERMS:** Available DER resources (retrofit opportunity) **DERMS:** Identify existing issues including reverse flow
Commercial & Industrial Customer Count	Number of Commercial & Industrial customers per bank	**BTM Storage, DERMS:** Potential energy storage customers for control

[19] Final EPIC reports on each of these projects including further information on site selection and customer acquisition can be found at: https://www.pge.com/en_US/about-pge/environment/what-we-are-doing/electric-program-investment-charge/closeout-reports.page

Solar Adoption Potential	Projected growth of solar over the 2015-2019 timeframe	**Smart Inverter, DERMS:** Potential solar DER resources, and grid impacts
Storage Adoption Potential	Projected growth of distributed storage over the 2015-2019 timeframe	**BTM Storage, DERMS:** Potential energy storage DER assets, and grid impacts
Presence of SCADA	Existing SCADA telemetry on feeders	**DERMS:** More cost-effective roll-out if SCADA is already present on the feeders

In the end, one of the biggest drivers was the location of PG&E owned DERs. With all the unknowns around customer acquisition, having a known controllable asset of significant size was a primary reason for choosing the three feeders in the San Jose area.

The lack of actual distribution capacity and voltage issues on these feeders made them a good candidate for an MVP DERMS system because they could be decommissioned without negative effects on the feeders. However, this meant that the project would only address simulated issues. Additionally, the stiffness[20] of these particular feeders made it difficult to materially influence medium voltage with the available DERs.

4.4 DER Asset Deployment

The coincidence of DER location, volume, and availability with the distribution need are all important factors to enable DERs to provide distribution grid services. Challenges related to customer acquisition, permitting and interconnection processes for non-standard or nascent DER arrangements significantly impacted the amount of controllable 3rd party DERs available to the DERMS Demo. The unanticipated nature of these challenges formed a key learning for setting future expectations and strategies regarding location-specific DER acquisition for grid services. Table 4 shows the deployment targets and actual results.

Table 4: DER Deployment Targets, Actuals, and Delays for the Combined EPIC 2.02, 2.03A, and 2.19 Projects

DER Asset Type	Targeted Deployment	Achieved Deployment	Schedule Delay
Residential Solar	500kW	124kW	10 months behind schedule
Residential Storage	150kW for 4 hours	66kW for 4 hours	2-4 months behind schedule

[20] Stiffness refers to the ability of the system to resist deviations resulting from variations in connected load or generation

Commercial Storage	350kW for 4 hours	360kW for 2 hours	2-4 months behind schedule

Organic growth of dispatchable DERs at the scale required to create a meaningful impact where needed is a challenge in the near-term. However, with the continued growth and penetration of DERs, especially dispatchable energy storage, this may be less of a challenge in the future.

4.4.1 Customer Acquisition

Customer acquisition was more difficult than anticipated. Targeting a DER deployment to a specific geographic area severely limits the sales funnel for customer acquisition. It constrained the group of possible customers outside of the DER developers' usual marketing parameters like customer load profile, rate class, and demographics. This made sales conversions more difficult, even with the offers of additional incentives funded by the project to encourage adoption.

PG&E originally identified an area covering approximately 1,800 PG&E customers for customer acquisition and retrofit. Among these customers, there were 200kW of existing solar capacity where conventional inverters could be potentially retrofitted with smart inverters. Ultimately, **the vendor was unable to use existing installations because the majority of the vendor's existing systems were not owned by customers or the vendor**. Instead, these residential systems were batched and financed through large financial institutions, where the securitized nature of system ownership prohibited any reduction of system active power output.

As a result, the vendor only targeted new residential customers. PG&E expanded the area to cover approximately 8,500 customers, and the project offered two incentives: a free battery from the vendor and a one-time bill credit from PG&E. The bill credit more than compensated for any possible electric rate cost impacts of the project demonstration period. The free battery storage device was key to landing the participating customers. The vendor sent ~2400 customer mailers and participated in additional marketing outreach, including door-to-door sales, to target a significant portion of the customers on the demonstration feeders.

For the commercial customers, the project funded incentives to improve the portion of customer's savings as related to the vendor's shared savings model.

Even with these incentives for the two customer classes, the total number of assets delivered by the vendors was below the project's targets. The acquisition process also progressed more slowly than planned, thus delaying the start of the subsequent permitting and interconnection steps.

4.4.2 Permitting

A key step in asset deployment is installation approval by the Authority Having Jurisdiction (AHJ). For the DERMS Demo, installation of solar photovoltaic (PV) and energy storage required building permits for applicable trade disciplines.

Energy storage is a relatively new product at scale, and unfamiliarity with these systems means that interpretation of rules and process is not uniform across or within jurisdictions. This may have attributed to some of the variability in the process experienced by the two vendors. Moreover, there is the normal variability of AHJ review and inspection scheduling lead times, which can be difficult to anticipate given the fluctuating workloads of city departments.

Both aggregators encountered challenges in the permitting process which led to longer than expected timelines. For solar and energy storage, the number of inspection visits needed was non-standard and varied per site, with some being able to complete two stages of approval at once (e.g. electrical and structural), while others required scheduling separate inspector site visits (thus adding an associated lead time). Furthermore, many sites were inspected and approved without a structural discipline review and inspection of the bolt assembly used for wall mounting the residential battery. Partway through the project this issue began to require additional drawings and another inspection. The commercial storage vendor encountered an unexpected fire safety review from the AHJ which likewise caused delays.

The vendors addressed these challenges with proactive communication with the AHJ. While schedule variability still arose, **it was found advanced knowledge of requirements and early communication with AHJ officials can minimize schedule risk associated with permitting.** Such requirements should not be assumed to be transferrable across jurisdictions, but it is expected that processes will become more efficient and standard as energy storage becomes more common in the future.

4.4.3 Interconnection

The PG&E interconnection process ran in parallel with permitting during asset deployment. These new installations were required to complete the process outlined by the interconnection rules and tariffs in place for generating facilities[21]. The sites with solar sought NEM type interconnections, while the commercial storage sites sought Non-Export type interconnections.

The interconnection process was also highly variable and took longer than anticipated. While both the vendor and the utility had mature processes in place for PV-only interconnections, standardized processes around residential storage are still evolving. **While the project team took steps to tightly manage the interconnection requests, the total interconnection process time, including associated dependencies on permitting and approvals, varied from 8 to 27 weeks for the residential systems.** This, compounded by the slower than expected sales cycles, reduced and delayed asset availability for the projects.

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[21] https://www.pge.com/en_US/business/services/alternatives-to-pge/generate-your-own-power/distributed-generation/distribution-handbook.page

4.4.4 DER Assets Available to DERMS

Given the customer acquisition, permitting, and interconnection challenges, the final fleet of DER assets used for testing was less than anticipated, but included the following three groups shown in Figure 4:

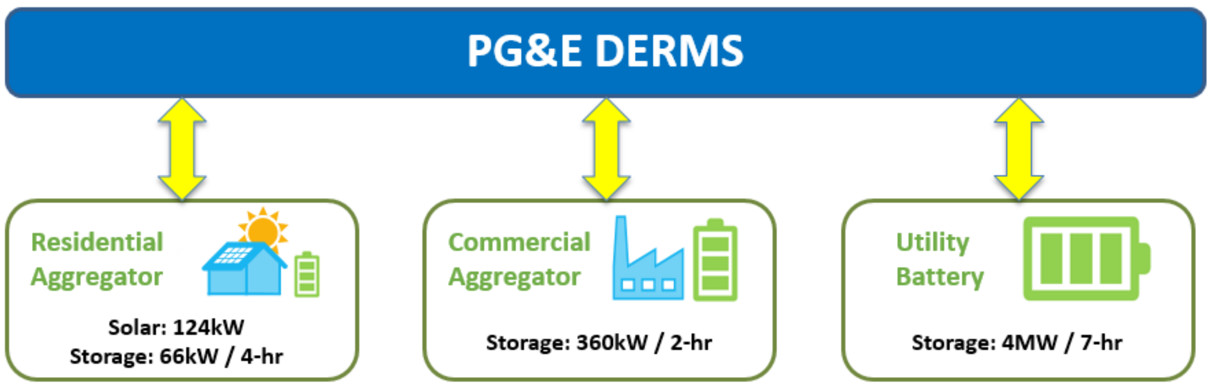

Figure 4: DERMS Demo DER Asset Fleet

Residential Solar + Energy Storage

The residential solar with storage assets consisted of a total of 124 kW PV with 66 kW of 4-hour duration storage across 27 residential sites. These sites were equipped with smart inverters and energy storage systems of capacities of either 1.6 kW or 3.2 kW (at 4-hour rated duration). The PV nameplate capacity ranged from 2.6 to 8.5 kW. The sites were interconnected under the NEM-Paired Storage provisions of the NEM tariff and Electric Rule 21. The sites were installed before smart inverter UL1741-SA certification[22] was required, but had the functionality required for demonstration.

Commercial Energy Storage

The commercial customer sites with energy storage consisted of a total of 360 kW of 2-hour storage across 3 sites[23]. These were smart inverters tied to 120 kW of energy storage per site. These assets were Non-Export type interconnections under Electric Rule 21. The sites were installed before smart inverter UL1741-SA certification was required, but they included that functionality.

Utility Owned Energy Storage

One stand-alone market-participating energy storage asset under PG&E ownership was used for the demonstration. This storage facility, named the Yerba Buena Battery Energy Storage System (YB BESS),

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[22] https://industries.ul.com/wp-content/uploads/sites/2/2016/08/UL-1741-SA-Advanced-Inverters.pdf

[23] The storage only assets were labeled as 120kW 2-hour assets (240 kWh), even though they could store ~ 270 kWh. The vendor upsized the battery to provide the full contracted range, while being able to maintain a minimum state of energy in the battery (~30 kWh).

was the subject of a prior EPIC project, EPIC 1.01 – Energy Storage End Uses[24]. The storage device is a 4 MW, 7-hour battery connected under the Wholesale Distribution Tariff.

4.5 Smart Inverters

The ability to dispatch DERs to perform grid services is largely dependent upon the intrinsic capabilities of the inverter or site controller. Smart inverter functionality is rapidly evolving due to a number of external drivers including the progress of Electric Rule 21. Over the course of the DERMS Demo, some of these new capabilities have become standardized and certifiable (Compliance with UL1741-SA starting in September 2017), with more functionality scheduled to be certified in 2019. Because customer acquisition was done prior to the existence of certifications for the required functionality, the DERMS Demo leveraged EPIC 2.03A and EPIC 2.19 to test some of this new smart inverter functionality, with further testing done within the project. In the design phase of the DERMS Demo, vendor implementation of functionality was self-defined or loosely defined around adaptation of various standards, so considerable effort was spent with the aggregator vendors to understand their current product offering to create a uniform transaction of data with PG&E.

Additionally, the relative nascency of the technology led to some technical challenges with the hardware, including the residential smart inverters having issues properly controlling sites where two DC-coupled batteries were installed, ultimately requiring one of the batteries to be disabled. **Continued involvement is needed from all parties to ensure that standards, protocols, and certifications continue to evolve to promote the needed functionality and harmonization of smart inverter capabilities and integrations as the industry grows.**

5 DERMS Demo Implementation

5.1 Overview

The DERMS Demo was implemented as a MVP to focus on learnings rather than a long-term scalable solution for a very uncertain future. This approach successfully provided the necessary flexibility to learn and iterate, but would need additional investment to scale to a production system. Significant development was required to define architectures and integrations, enable new functionality, create a standards-based aggregator interface, and test market interactions. The implementation lessons learned from this process were critical in defining, implementing, and managing near-term DER solutions via the 2020 and 2023 General Rate Case (GRC) filing, candidate distribution investment deferral projects, and upcoming research and demonstration projects.

[24] https://www.pge.com/pge_global/common/pdfs/about-pge/environment/what-we-are-doing/electric-program-investment-charge/PGE-EPIC-Project-1.01.pdf

5.2 DERMS Demo Components and Architecture

A comprehensive DERMS is not a readily available product from any vendor. As such, the DERMS for this project was built through an integration of new and existing systems. A complex ecosystem of installed and cloud-based servers supported the DERMS Demo components and enabled more than 10 interfaces connecting PG&E's internal utility data network, a more secure operational data network, and external aggregators. A simplified diagram of the DERMS architecture is shown in Figure *5* with major components described in the paragraphs below.

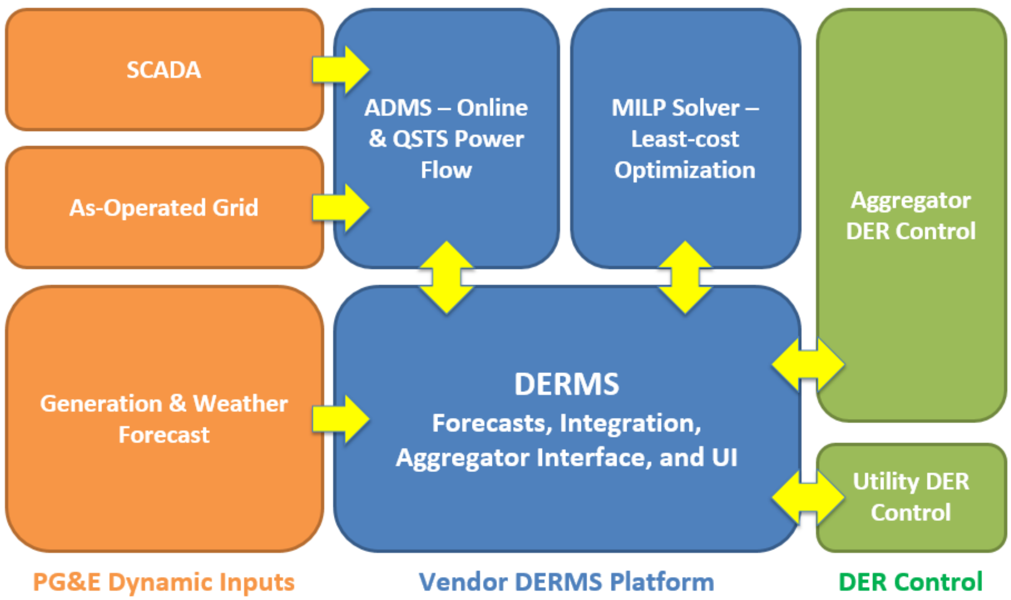

Figure 5: Simplified DERMS Architecture

ADMS: The DER-aware ADMS was the foundation for all electrical calculations and situational awareness for the DERMS. PG&E did not have an existing ADMS; therefore, a new scaled-down ADMS was deployed temporarily for the DERMS Demo on the three demonstration feeders. The underlying model in the ADMS was built using static PG&E data gathered from a variety of sources. ADMS used dynamic inputs from PG&E's production SCADA and DMS systems for real-time telemetry and the as-operated topology of the grid to run online power flow calculations every 5 minutes. These calculations provided real-time situational awareness for the operator to determine the impacts of DERs and what was happening at any point on the grid.

In addition, the ADMS facilitated Quasi-Static Time Series (QSTS) offline power flows to forecast power system parameters at any point in the system by leveraging ingested generation and weather forecasts from PG&E. The ADMS also drove the calculations of electrical grid needs and DER sensitivities (V/kW, V/kVAR, A/kW) to determine where there were specific voltage or capacity needs and the impact an aggregated DER could have on those needs.

Commercial Mixed Integer Linear Programing (MILP) Solver: The MILP solver used information from the ADMS along with other constraints and economic data input into the DERMS to create a least-cost optimization (See Section 8.2.1 for additional information) to efficiently dispatch DERs to mitigate grid needs or provide energy arbitrage.

DERMS: The DERMS platform integrated the ADMS and MILP solver functionality with the forecasting, user interface, and aggregator interface used for communication and dispatch of DERs. Optimization plans for DERs were presented to the DERMS Operator[25] to be dispatched via an automated IEEE 2030.5 Aggregator Interface to DER aggregators. While the optimization included the utility owned battery, it was dispatched outside the aggregator interface due to security controls. Day-ahead ask-bid-commit and hourly ad-hoc market structures provided the mechanisms for aggregator interactions and timing of dispatches.

5.3 Aggregator Interface

The DERMS Demo implemented a specialized IEEE 2030.5 Aggregator Interface with custom extensions for market based DER field control between a utility and 3rd party aggregated DER assets.

Figure 6 shows a high-level diagram of the communications implementation between the DERMS and the DER aggregator assets. The DERMS interface was created to only communicate with aggregator software solutions. Therefore, the DERMS did not have to directly connect with every inverter in the field; instead it relied on the aggregators for communication and dispatch to end devices. This also meant that PG&E did not have direct visibility or control over individual assets. However, to be able to verify responses for testing purposes, the aggregators provided a separate daily log file showing the output of individual DERs to compare against the aggregated information provided to the DERMS.

[25] The DERMS was not fully integrated into production Operations systems at PG&E based on the MVP implementation. Therefore, a member of the DERMS Demo project team was the “DERMS Operator” managing the DERMS system.

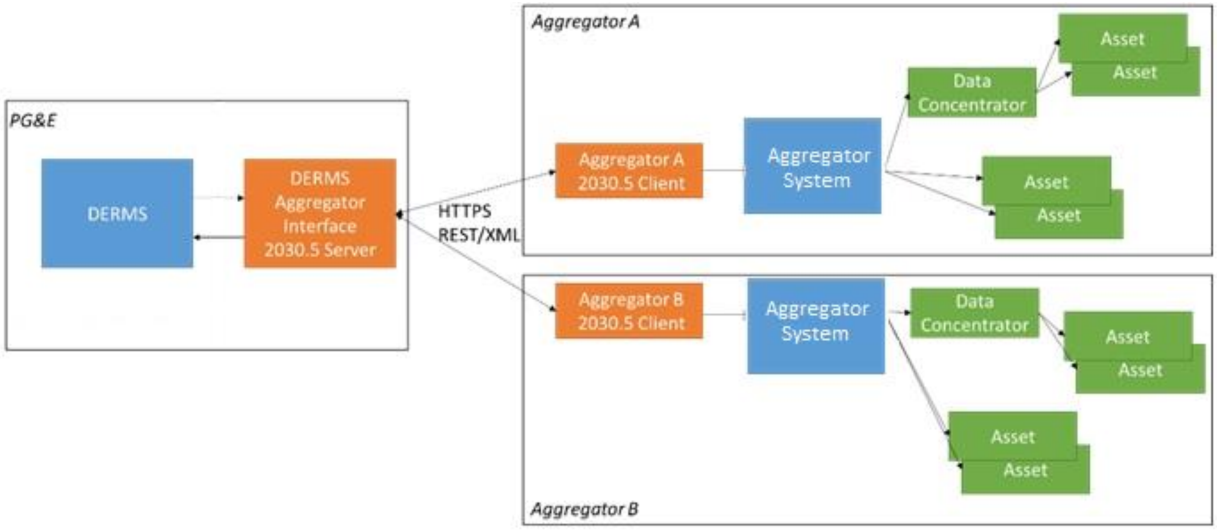

Figure 6: High Level Communications Architecture Diagram

5.3.1 Protocol Selection

At the start of the project, there was no widely-adopted standard method or protocol for establishing a utility-to-aggregator interface. The two protocols considered for this project were OpenADR 2.0b and IEEE 2030.5. OpenADR was widely known for its demand response capabilities. IEEE 2030.5 was managed by the Smart Energy Profile 2.0 (SEP2) Working Group, and California's Electric Rule 21 Smart Inverter Working Group (SIWG) recommended it be used as the default communication protocol for utility-aggregator interfaces for smart inverter-enabled DERs[26].

Table 5 is a high-level summary of the pros and cons of each at the time, with neither protocol fully able to implement all of the functional requirements to meet the goals of the DERMS Demo out of the box.

Table 5: Pros and Cons of Using IEEE 2030.5 and OpenADR 2.0b for DERMS Demo in Early 2016

	IEEE 2030.5	OpenADR 2.0b
Pros	• Supported by SIWG • Base protocol already supported by DERMS vendor and one aggregator – Less cost and shorter schedule to implement	• Well established for Demand Response use cases • Well suited for market environments
Cons	• Market functions more difficult to implement	• Did not support reactive power • Did not leverage smart inverter functionality –

[26] Recommendations for Utility Communications with Distributed Energy Resource (DER) Systems with Smart Inverter.

	• **Custom extensions required**	meaning a separate translation layer was needed to harmonize with vendor inverter systems • Not supported (at the time) by either aggregator - Additional cost and schedule length to implement • **Custom extensions required**

Through collaboration among the DERMS vendor and the aggregators, IEEE 2030.5 was chosen as the most efficient protocol to implement for this project given current capabilities of the parties and perceived long-term adoption. The project leveraged the SIWG draft recommendations by implementing utility aggregator communications interfaces based on both the IEEE 2030.5[27] standard and the guiding document[28]. Since the inception of the project, Electric Rule 21 has also included IEEE 2030.5 as the default application-level protocol. More information on the considerations supporting IEEE 2030.5 and the custom extensions implemented for the DERMS Demo can be found in Section 14 – Appendix.

5.3.2 Aggregator Interface Development

The implementation of the DERMS Demo Aggregator Interface was unique and required significant development on the part of the DERMS vendor, as well as both DER Aggregators. The interface was the base for all interactions between the DERMS and 3rd party DERs, and therefore considerable discussion among the parties was necessary to ensure the shared understanding and development of definitions, capabilities, processes, and operational rules.

More development is required to develop and standardize these types aggregator communications. PG&E and industry leaders should continue to be engaged in the various standards, policy, and regulatory bodies that are shaping utility to aggregator interactions.

5.4 IT Architecture and Cybersecurity

Careful consideration was needed to develop the IT architecture of DERMS to integrate both with the secure parts of the internal utility network, like SCADA, as well as the public internet to connect with 3rd party aggregators. PG&E developed three environments for testing and deployment, including Production, Quality Assurance, and Development environments.

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[27] Smart Energy Profile 2, Application Protocol Standard, April 2013
[28] https://www.pge.com/includes/docs/pdfs/shared/customerservice/nonpgeutility/electrictransmission/handbook/rule21-implementation-guide.pdf

All application and server access was controlled through Active Directory integration for authentication, with no locally stored passwords. Most of the DERMS servers resided in separate virtual LAN configurations in the internal PG&E cloud infrastructure, with certain parts hosted in PG&E DMZ (Demilitarized Zone) environments. The Internal Cloud platform provided faster staging of traditional Production, Quality Assurance, and Development environments with the same security policies and integration processes as locally hosted servers. It also provided built-in disaster recovery functionality.

Users accessed the DERMS interface through web browsers with integrated user access controls. Any ADMS modifications for testing were done through an ADMS thick client.

The Aggregator Interface was the only external facing portion of the DERMS. An interface server hosting the adapter for communications between the DERMS and the Aggregator Interface platform was hosted in a DMZ. The latest Application Delivery Control (ADC) platform was deployed to provide combined gateway, load balancing, firewall, and deep packet inspection capabilities (Figure 7).

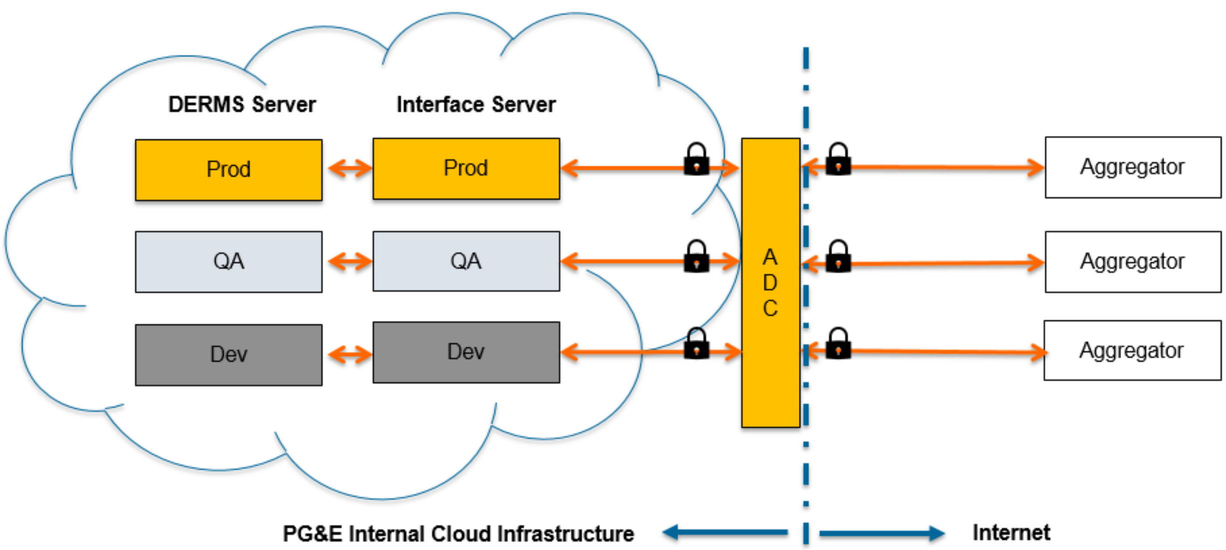

Figure 7: High-Level Aggregator Interface Implementation Diagram

A certificate process was created to ensure only valid connections were being made to the DERMS from 3rd party entities. The interface server provided trusted certificates to allow aggregator access. The ADC validated the client certificate and inserted the client ID into the data stream before sending to the DERMS applications. Valid aggregator client certificates were required to authenticate an aggregator HTTPS connection request to the DERMS server. The aggregator connection was terminated at the ADC and the package was forwarded to the DERMS interface server after passing authentication.

5.5 Aggregation Definitions

Static aggregations of assets were defined by PG&E based on vendor, capabilities, and locational impact on the grid to fulfill the proposed demonstration use cases across the EPIC 2.02, 2.03A, and 2.19 projects.

The project defined two concepts for aggregations as illustrated in Figure 8:

- **Aggregated DER (ADER):** A grouping of one or more physical DER assets with similar characteristics in terms of capabilities, sensitivities, and ownership
- **Aggregation Node**: A grouping of one or more ADERs or Aggregation Nodes defined by grid needs or impacts

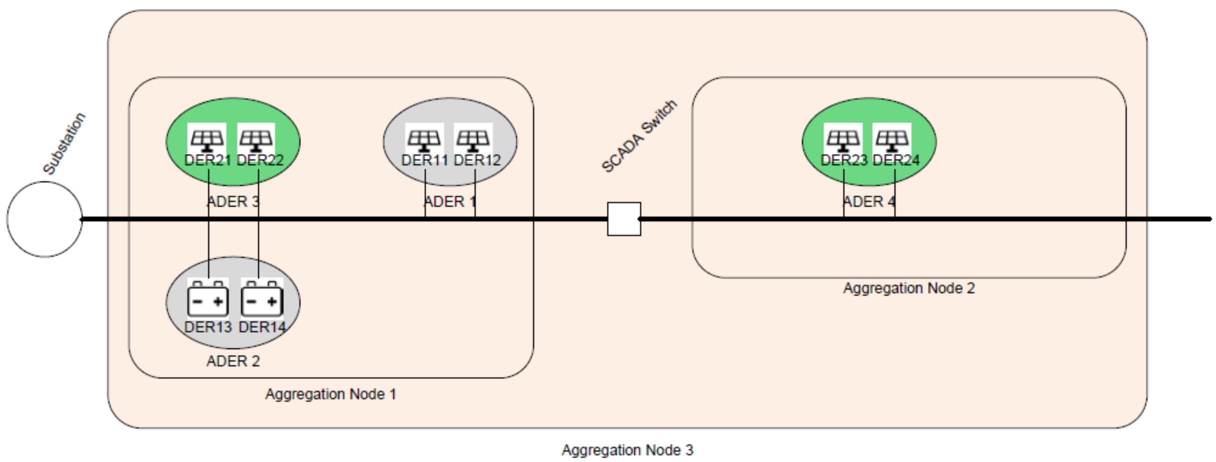

Figure 8: Example of Aggregated DERs (ADERs) and Aggregation Nodes with Two DER Aggregators (Green and Gray)

Aggregation nodes were determined based on the available utility SCADA devices and the grouping of available DERs. ADERs were grouped by location, asset capabilities, vendors, and shared use across the three EPIC projects. Figure 9 shows the actual ADERs and Aggregation Nodes used for the DERMS Demo. The colored areas are the different Aggregation Nodes, while each of the diamond shaped symbols represents an ADER (representing multiple grouped individual DERs).

Figure 9: DERMS Aggregation Nodes and ADERs

While the aggregations were static based on the MVP implementation, **future implementations of aggregations should be dynamic to consider variability in the asset mix and availability, abnormal grid topology, economics, and programs rules to most efficiently provide distribution services.** The most efficient aggregations to address a grid need will group DERs based on availability and impact. For example, topological aggregations make sense when solving for capacity issues downstream of a device, but groupings based on voltage sensitivity may make more sense for voltage related issues. Similarly, **sensitivities may be a way to group assets based on the effect they have rather than topology alone.** Moreover, there will be layers of groupings that include programs, vendors, or constraints that may be dynamic as well.

Aggregating by phase is also important especially when considering residential DERs. These units will only have an impact on the one or two phases they are connected to, and will not resolve an issue on unconnected phases. Additionally, there is a need to avoid creating issues with system phase imbalance by coordinating phased dispatches within distribution limitations.

Aggregation of DERs is currently being explored in further detail by the Electric Power Research Institute[29] in collaboration with industry stakeholders. Further work in this area will be important to create scalable and standard integrations with aggregated DERs.

5.6 Market Mechanisms

Evolving policies, rules, and regulations guiding the mechanisms for DERs to provide distribution services in an operational time frame, foster continued discussion whether distribution services should be mandated, based on bilateral market contracts, customer programs, facilitated through some type of distribution market, or a combination thereof.

To maximize learnings and dive into the most complex type of mechanism, PG&E chose to implement two types of test distribution markets for the DERMS Demo without endorsing either approach: A day-ahead ask-bid-commit market, and an hourly ad-hoc market. DERMS dispatched active-power (kW) in both markets, while reactive-power (kVAR) was only dispatched in the hourly ad-hoc market[30].

Both markets required DERMS to first provide grid needs to the aggregators based on real-time or forecasted capacity or voltage violations. The day-ahead interface would publish an active-power ask to the aggregators based on forecasted needs over the next day's 24-hour period. The aggregators would then respond to the DERMS with a bid offer of price and energy. The DERMS would then publish and commit awards to the aggregators based on a least-cost dispatch.

Flexibility forecasts, which were defined as the hourly available capacity (kWh) from the DERs, were provided by the DER aggregators every hour encompassing the next 36-hours, and depending on the type of asset, would include the impacts of solar generation, committed wholesale awards, energy storage limits, initial states of charge, and pricing. An example of the flexibility offered by a particular aggregator is shown in Figure 10, where generation/export is shown as Up Flexibility, and additional load (or curtailment of solar generation) is shown as Down Flexibility. In the ad-hoc market the DERMS would use the latest hourly flexibility information (or kVAR capabilities) to minimize capacity and voltage violations over the next 24-hours using the least-cost assets.

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[29] EPRI has ongoing DER Group Management work including through their P174 Integration of Distributed Energy Resources Program and DERMS Working Group:
https://www.epri.com/#/pages/product/3002008215/?lang=en-US
https://www.epri.com/#/pages/product/000000003002014468/?lang=en-US

[30] While a combined active and reactive power optimization is desired for real-time and day-ahead dispatch, these were split for the DERMS Demo based on the MVP implementation.

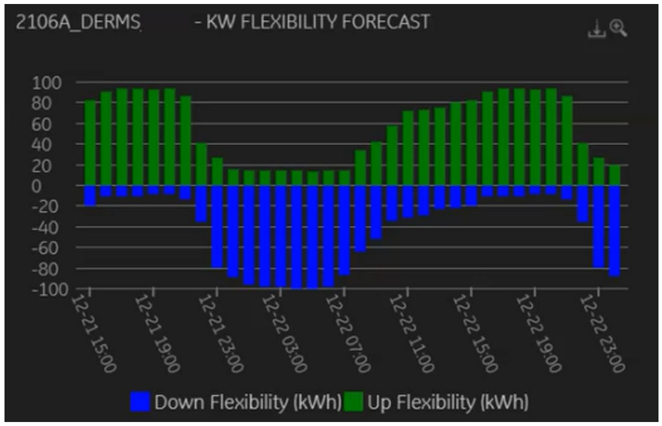


Figure 10: Aggregator Provided Flexibility Example

While future market dispatches may run autonomously, a DERMS Operator made the final decision to approve a particular dispatch for the demonstration. Keeping a human in the loop allowed for scrutiny of the system for both optimization parameters and adherence to constraints.

The day-ahead ask-bid-commit interface was initially timed to occur after wholesale market actions, but these timings were modified during MUA testing. Flow charts of both market types are provided for reference in Section 0 – Appendix.

Determining real-life price valuation of violations and DER services was not in scope. Therefore, valuation and DER service prices were designed to emphasize distribution capacity and voltage violation mitigation.

6 Enhanced Situational Awareness: Project Activities, Results, and Findings

6.1 Overview

As the complexity of the power system continues to increase with the growth of DER penetration, Operators require new tools to allow them to safely and reliably operate the grid. Existing methods of using SCADA data to monitor net load for switching or other operations fail to identify the masked load[31] effects of connected DERs that could potentially impact those operations. Ad-hoc modeling studies by Engineers provide added insight, but this requires manual analysis and may not fully represent the impacts of DERs on the system. Furthermore, as the industry moves towards more automation of grid operations, programs such as Fault Location Isolation and Restoration (FLISR), and

[31] "Load Masking" describes a situation in which the lack of generation output visibility prevents system operators and engineers from determining the real system load conditions which can inhibit the ability to plan and operate the distribution system. This is discussed in the CPUC Interconnection Rulemaking (R.17-07-007) Working Group One Final Report, issued March 15, 2018.

Volt-VAR Optimization (VVO), in addition to DERMS require foundational information about the power system and connected DERs to function safely and efficiently.

PG&E currently lacks the foundational technology not only to enable a DERMS but also to provide modeling and situational awareness capabilities that are needed to operate an increasingly complex grid. The learnings from this project showed that **PG&E needs to invest in foundational technology including improved data quality, modeling, forecasting, and a DER-aware ADMS to address the near-term impacts of DERs and grid complexity while providing the groundwork for a future DERMS system.**

6.2 Technical Development and Methods

An ADMS uses load allocation, load flows, and state estimation to calculate the power system values at every point in the grid. This demonstration allowed PG&E to evaluate one vendor's ADMS capabilities to provide these for both real-time and short-term forecasts. While different vendors and/or algorithms may produce different levels of accuracy, the goal was to directionally determine the confidence that could be placed in such products, as well as document learnings to improve results that could be used in future projects regardless of vendor.

Because this is new functionality for PG&E, quantifying the accuracy was important to provide confidence in consequent manual or automated actions taken based on those calculations.

The DERMS output accuracy was verified by comparing to both actual measurements in the field and PG&E's internal trusted power system modeling software, CYME. The team compared snapshots at single points in time as well as across multiple time intervals.

The following sections describe the challenges and results of evaluating the situational awareness capabilities of the ADMS based on the following categories:

- 3-Phase Unbalanced Power Flow Accuracy (Including Net and Masked Loading)
- Impact of Improved Phasing Data
- Impact of Improved SCADA Data
- Real-time vs Forecasted Loading Accuracy
- Aggregator Flexibility Forecast Accuracy
- Micro Phasor Measurement Unit Benefits

6.3 Challenges

6.3.1 Data Quality

Data quality is a significant concern for utilities as they begin implementing more data driven applications. Issues with the underlying modeling or telemetry data can negatively impact the ADMS calculations, resulting in erroneous data displayed for Operators, or at worst, poor operational decisions being made manually or via autonomous controls.

6.3.1.1 Model Data

At the start of the DERMS Demo, much of the model information required to stand up the foundational ADMS was in disparate systems, sometimes with duplicative or incomplete information. A parallel PG&E effort to consolidate and clean these systems used experience from the DERMS Demo implementation to inform some of the development. While there continues to be improvement in this area, the progress made thus far will allow for a more accurate and streamlined rollout of any future ADMS.

One of the largest gaps in model data was information about phasing. Phasing data refers to mapping three-phase physical power system phases (i.e. A, B, C) to transformers, customers, or devices. PG&E currently has no phasing data for its system, but by partnering with the EPIC 2.14 – Automatically Map Phasing Information project, the DERMS Demo showed how this information improves system modeling accuracy.

Recommendations:
Utilities need to invest in foundational data quality and modeling capabilities to enable the advanced functionality required to operate an increasingly complex grid. PG&E is proposing these improvements, including gathering phasing information, via the IGP strategy and for the 2020 and 2023 GRC filing. This is expected to be a continuous improvement process, and strategies to prioritize data quality efforts based on needs will result in more efficient solutions.

6.3.1.2 Field Telemetry

This project verified SCADA data coming from utility field devices to ensure that data coming in was adequate for use in the ADMS power flow calculations. Eighteen devices thought to be critical to these calculations were field verified through physical inspections to ensure accurate readings in terms of magnitude and phase. Because PG&E did not require phasing data in the past, this was the biggest area for improvement from the field telemetry. Figure 11 describes the results of this field verification process for the demonstration feeders. These results do not necessarily reflect the overall state of the system at large but do offer insight into potential problems facing an ADMS roll-out.

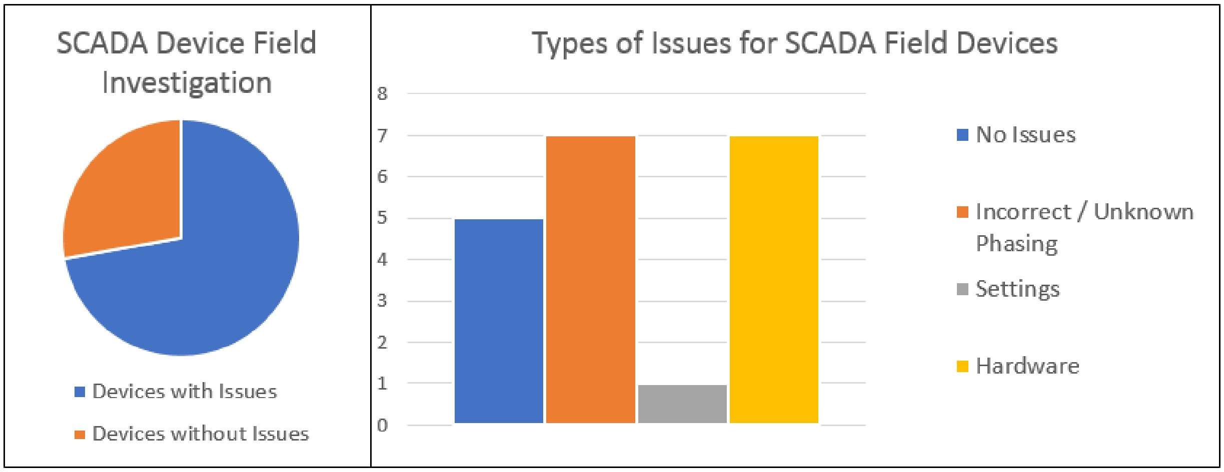


Figure 11: SCADA Device Field Verification Results

In addition to existing field issues, the project could have benefited from more data, specifically voltage, kW, and kVAR data. The most prevalent SCADA data on the system is amps, but alone this does not help to disaggregate the effects of kW and VARs per phase, nor does it provide the direction of power flow. The lack of data created modeling inaccuracies especially in voltage calculations and the disaggregation of kW and kVAR along the feeder.

Recommendations:
Field verification and correction of a portion of field devices will be required to enable accurate power flow calculations in ADMS**. Priorities should be developed based on the impact they have on the results, and importance of the needs.** Tools to help identify outliers for investigation are often available in ADMS systems through looking at state estimation or power flow convergence results. Moreover, field processes need to adapt to ensure actions are taken upfront for newly installed or retrofitted devices including phase identification.

At a minimum, kVAR and kW per phase at the circuit breaker level should be added to the existing total kVAR and kW values to better enable unbalanced power flow. Voltage data from SmartMeters should also be used in future systems to better inform voltage calculations beyond available SCADA data. Furthermore, simulating setting information around capacitor banks, and issues around estimating capacitor bank states could be simplified with some SCADA connected capacitors. This could also enable future automated control of these devices for programs like Volt VAR Optimization.

It is unreasonable to assume that data from the field will be completely free of issues, including communication problems and device failures. Proper failsafes should be put in place to protect against these types of issues impacting grid operations negatively, to the degree possible.

6.3.2 Impacts of Large Highly Variable Loads

The 4MW YB BESS was a significant load on the system, sometimes causing negative MW flows at the feeder circuit breaker. In addition, the participation of this battery primarily in the frequency regulation market (CAISO Ancillary Services: Regulation Up and Regulation Down) created a situation where the battery could potentially swing almost 8 MW in a 4 second period. Figure 12 shows the impact on the load profile created by YB BESS in the frequency regulation market.

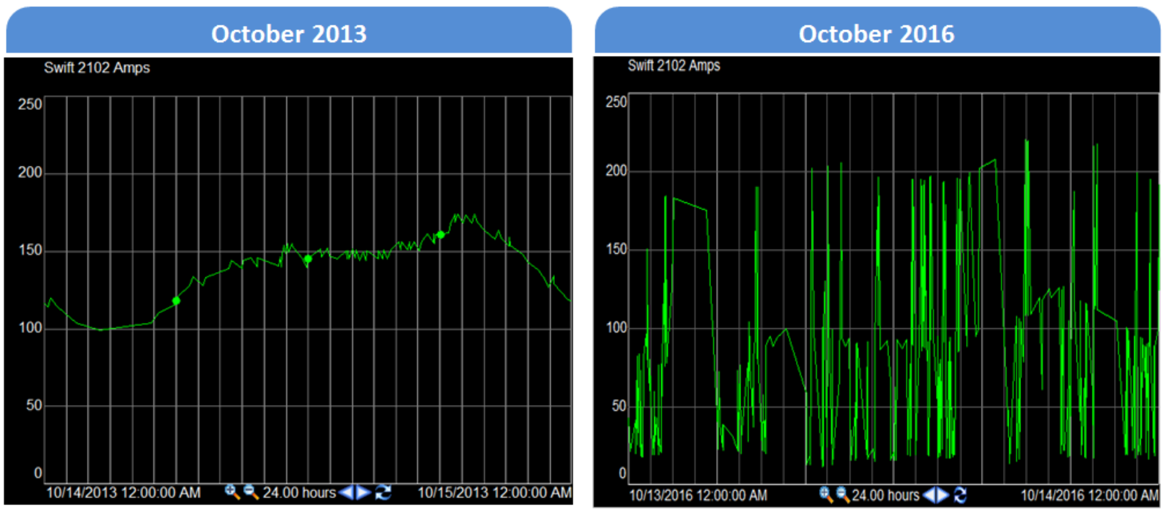


Figure 12: Impact on Feeder Loading of Yerba Buena Battery Participating in the Frequency Regulation Market (Amps)

The battery operating in the frequency regulation market made it difficult to forecast, and made real-time analysis challenging with non-time-synched measurements from the field causing the power flow analysis to not converge.

The lack of synchronization between the YB BESS SCADA data updating every 4 seconds and the feeder head SCADA data updating every 30 seconds to 1 minute caused three measurement islands to not converge and be dropped, introducing error into the power flow results.

Recommendations:
To help mitigate the ambiguity of forecasting the battery participating in the frequency regulation market, the DERMS team implemented bands around the forecasted net loading to indicate the potential worst-case loading using an advisory day-ahead schedule from the PG&E Short Term Electric Supply (STES) team who manage the battery's market participation (Figure 13). While real-time awards may vary from the day-ahead schedule, it provided some insight for Operators into potential loading issues.

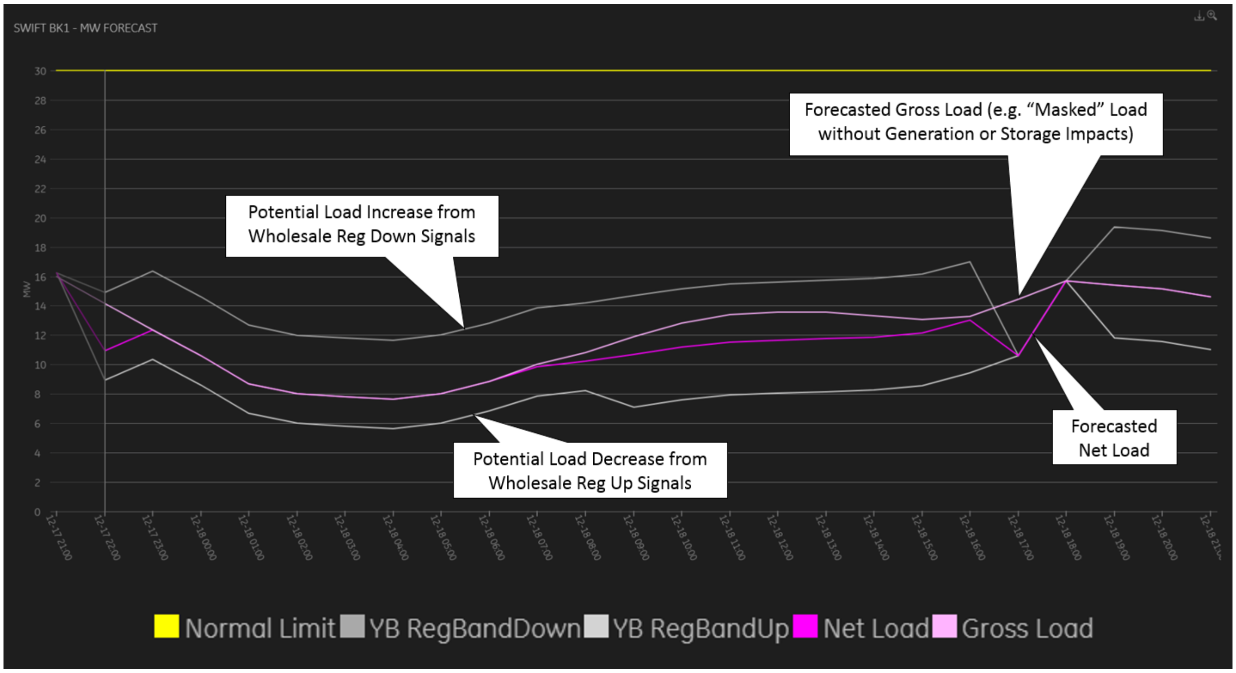


Figure 13: MW Forecast with YB BESS Regulation Bands Above and Below the Net and Gross Loading

Micro-Phase Measurement Units (PMUs) were installed at both the battery and the substation to mitigate the real-time situational awareness issues with time-synched measurements. The increased sampling rate and precise time correlation allowed for better convergence of power flows in the ADMS. This type of solution may be necessary in locations where power flows are required to converge and the size of the highly variable generation (or loads) are significantly impacting those calculations.

6.3.3 Forecasting

Short-term load forecasting capabilities were developed through this project and would need to be vetted for any production system. As operational processes and potential DER constraints or controls become more reliant on short-term forecasting, the relevance and accuracy of these forecasts become more important. Challenges with accurate real-time forecasts experienced through this project included issues with methods, model, and inputs.

Recommendations:
Continued research and investment to improve the accuracy of short-term forecasting and the underlying modeling is required to efficiently base automated controls and dispatches on this data. PG&E is investing in this through the IGP and proposed 2020 and 2023 GRC filing.

6.4 Results and Observations

6.4.1 Balanced and Unbalanced Power Flows

PG&E currently only runs balanced power flows because there is a lack of phasing information for loads or field devices. Balanced power flows can create modeling inaccuracy because load is spread evenly in the model without representing actual field conditions for phasing. This project provided the opportunity to field trial potential benefits from operationalizing an unbalanced power flow using the results from the EPIC 2.14 - Automatically Map Phasing Information project.

The quantified benefits described below are specific to the demonstration feeders. **The benefits and improvements of including phasing data will depend on the specific feeder characteristics as well as the amount of unbalance along those feeders.**

Table 6 shows the improvement in overall MAPE[32] using phasing information (unbalanced power flow in DERMS and CYME) at specific snapshots in time by running multiple power flow instances for a 24-hour period. Overall MAPE is the mean of the absolute percent error for all measurement comparison types including volts, amps, watts, and VARs where field measurements are available. MAPE values reported here are the combined mean of all the different types of measurement units.

Table 6: Balanced vs Unbalanced MAPE – Average of Multiple Snapshots

Overall MAPE	DERMS vs SCADA	CYME vs SCADA
Balanced Snapshot Average	15.3%	12.9%
Unbalanced Snapshot Average	9.8%	7.6%

Both the DERMS and CYME models had to be updated to include the new phasing information to run unbalanced power flows. A comparison of the balanced and unbalanced model using the same input data was run in CYME using its scripting abilities.

Average overall power flow MAPE was significantly reduced in an analysis over a 24-hour period when using the phasing data for an unbalanced power flow instead of a balanced power flow (Figure 14). This improvement varied with device location based on the current imbalance between phases. For example, the typical current imbalances at the three feeder breakers were 13%, 11%, and 16%. More detailed analysis can be found in Section 0 – Appendix.

[32] Mean Average Percent Error (MAPE) is described in detail in Section 16 - Appendix

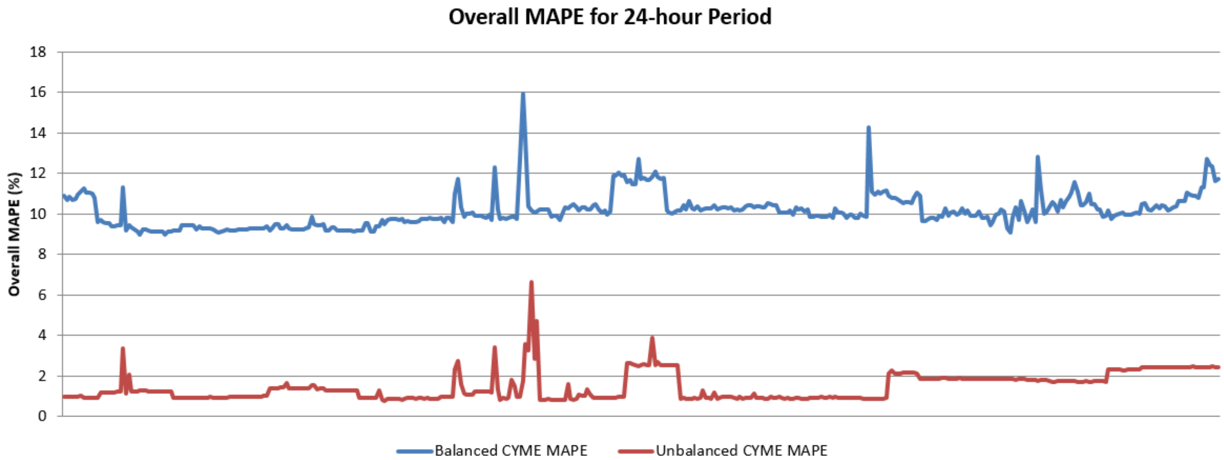


Figure 14: Balanced vs Unbalanced MAPE – 24-hour Period Direct Comparison

Once all the phasing data was incorporated and comparisons against the balanced model were completed, the DERMS ran the remainder of the demonstration with unbalanced power flows. It is expected that any future implementation of an ADMS will have appropriate phasing data and accuracy that is equivalent to the current offline tools used at PG&E, including CYME.

6.4.2 Telemetry Impacts

In addition to phasing data and the ability to run an unbalanced power flow, increased telemetry capabilities also improved calculation results.

6.4.2.1 Verified SCADA

More SCADA data does not necessarily mean better power flow results. In fact, the ADMS ran into convergence issues when unverified devices in close proximity were being used in the power flow, or if the values coming from these devices were not properly time-synched.

As discussed earlier, specific devices were field verified to ensure accuracy of their reported measurements. These verified locations were then used to inform the power flow. Figure 15 shows the improvement in MAPE for amps as more verified SCADA devices were used for both unbalanced and balanced power flows.

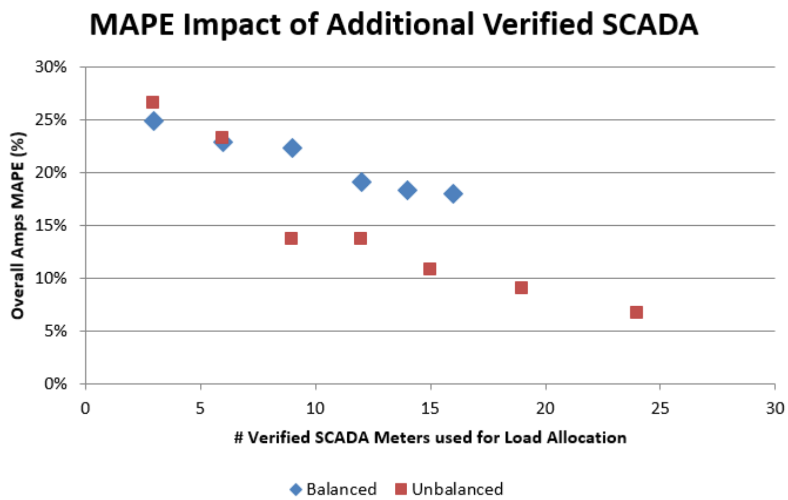


Figure 15: MAPE Improvement with Added Verified SCADA Devices

6.4.2.2 Time Synchronization – Micro PMUs

Power flow convergence issues were caused by using SCADA data that did not temporally align or update frequently enough when dealing with the rapid and significant changes in load caused by the YB BESS doing frequency regulation. This meant that the system could not fully find a solution to the modeling problem. Using PMU data, all measurement islands in the ADMS converged even when the YB BESS was performing frequency regulation.

Figure 16 shows the impact that non-time-synched measurements can have when trying to calculate power system parameters like feeder loading without the battery's output for potential planned switching. This should be a simple subtraction of the SCADA values of the YB BESS output from the SCADA values at the circuit breaker. The blue line does this subtraction using PMU measurements, while the orange line does the same subtraction using only SCADA measurements that are not time-synched. The error in the orange line is what Operators today deal with when trying to determine the net load on the feeder minus the impact of the battery.

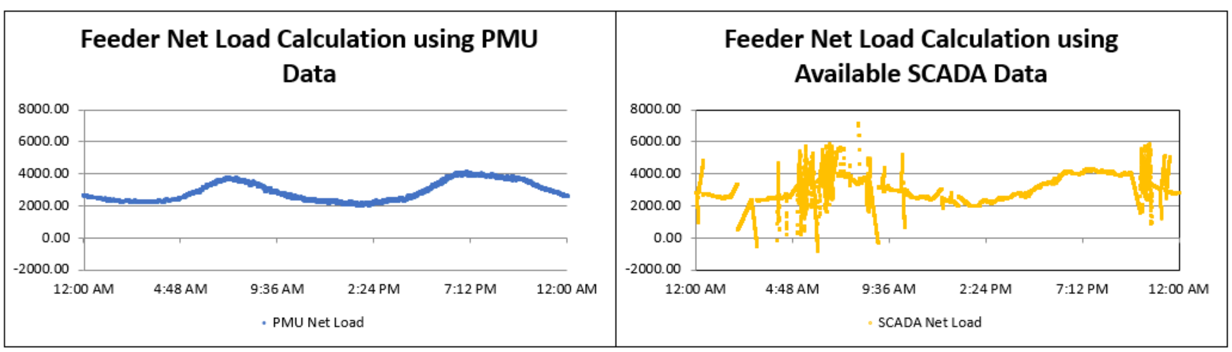


Figure 16: SCADA vs PMU Calculation Improvements with Highly Variable Loads

In addition to PMUs, there may be other methods (e.g. filtering, etc.) to help deal with these types of issues, however, for the purposes of this demonstration the PMUs provided a straightforward method to resolve the issue.

6.4.2.3 kW and KVARs

For this project, CYME was set to perform load allocation using measured amps at each device with the overall feeder power factor. The DERMS load allocation follows a measurement priority consisting of kW+kVAR > kVA > Amps. While kW+kVAR is preferred, PG&E did not have per phase kW or kVAR values at the feeder heads and only 3-phase total values were available. Therefore, the DERMS performed load allocation using measured kVA at each device. Most of the devices on the demonstration feeders also do not have three phase voltage measurements, so this is an additional source of error.

The use of kVA created some errors around the distribution of kW and kVAR among the phases, with the DERMS kW result being sensitive to errors in the kVAR allocation. After the PMUs were installed, the feeder serving the battery could be run as kW+kVAR.

Capacitor states in the DERMS ADMS power flow model were sometimes suspect based on comparisons of power flow results and measurements for kVAR, contributing to increased errors in the results.

One capacitor bank in the field was upgraded with a new SCADA capacitor controller. The actual capacitor state was reported in real-time for the power flows. The resulting error from incorrect capacitor states is illustrated in Table 7. As described above, the kVA allocation already created baseline errors in the kVAR calculations, and this was further worsened by incorrectly calculated capacitor states.

Table 7: Impact of Erroneous Capacitor States on Power Flow Results – 3/27/17 8:30PM with YB BESS Idle

	MAPE – Baseline	MAPE – 1 Capacitor wrong state	MAPE – 2 Capacitors wrong state
Voltage	0.91%	0.92%	0.98%
Current	18.65%	19.00%	23.30%
KVAR	114.96%	182.45%	278.61%

The DERMS ADMS and CYME had similar active power and reactive power results. The ADMS sometimes set one to two capacitor states incorrectly in its power flow model, which increased the error for both active power and reactive power. This was commonly observed on demonstration feeder 2107 as shown in Figure 17. The cause for this was investigated, and it was determined the power flow voltage was sometimes off by as much as 3%, resulting in the modeled capacitor controller behaving differently than the field because of the local voltage difference.

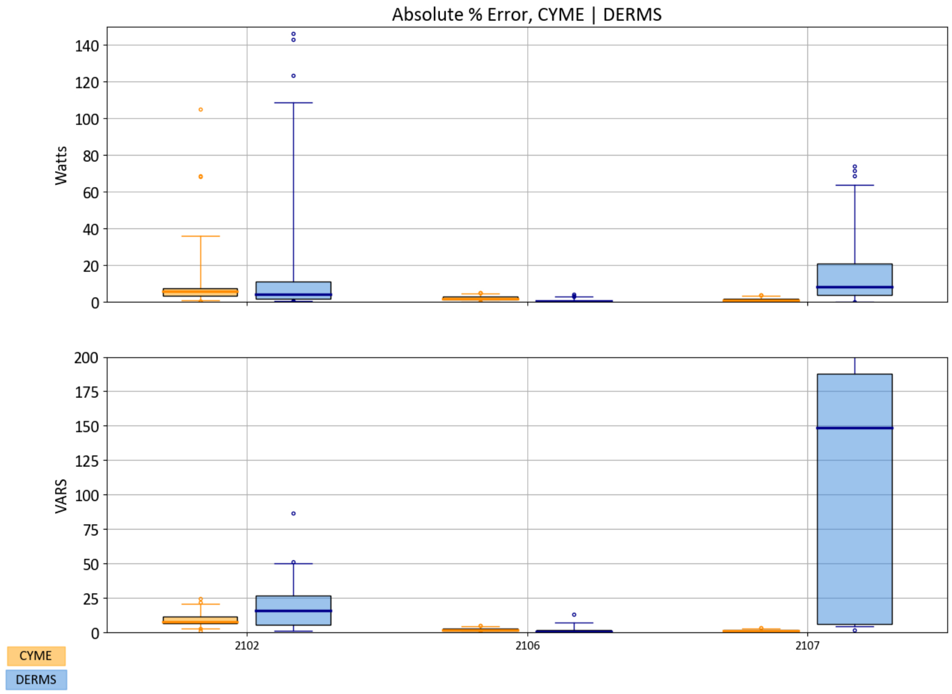


Figure 17: Real and Reactive Absolute Percent Error – CYME vs DERMS

6.4.3 Short-Term Forecasting

6.4.3.1 Load Forecasting

At the start of the DERMS Demo, PG&E did not have any short-term power system forecasting capabilities at the distribution level. Therefore, the DERMS / ADMS vendor built a forecasting engine from scratch using PG&E data and services. The goal was to forecast both net and masked (gross) loads at any point on the feeder as shown in Figure 18.

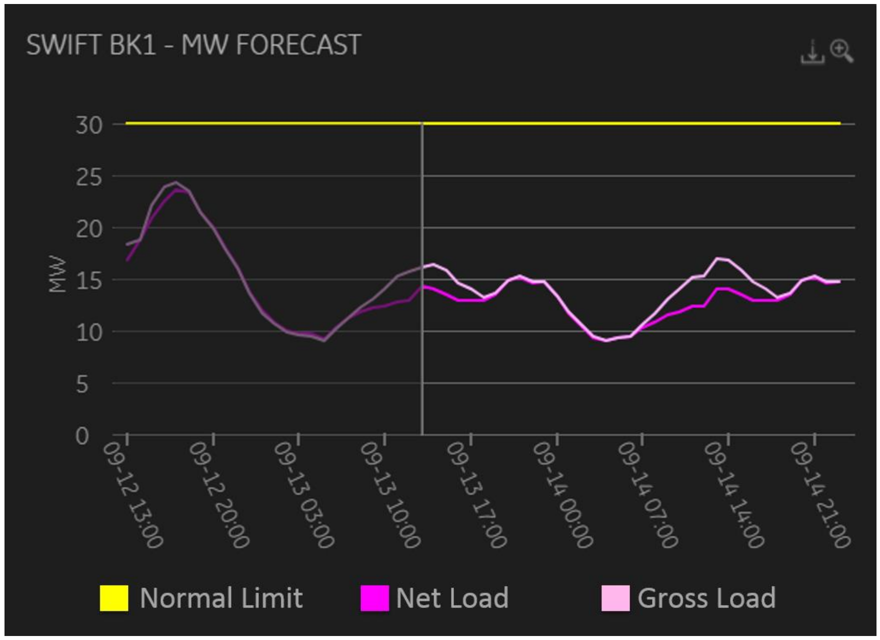


Figure 18: DERMS Screenshot of Historic and Forecasted Net and Masked Load

Solar PV generation forecasting was based on PG&E's SolSource tool that uses National Renewable Energy Lab's PVWatts generation model. Forecasts of generation were compared against actual generation at solar sites participating in the DERMS Demo. In general, the forecast was found to be slightly less than the actual at peak generating hours of the day. Figure 19 shows a comparison of the forecast to actual solar generation of 17 PV installations, by averaging the hourly values across 2 months of data.

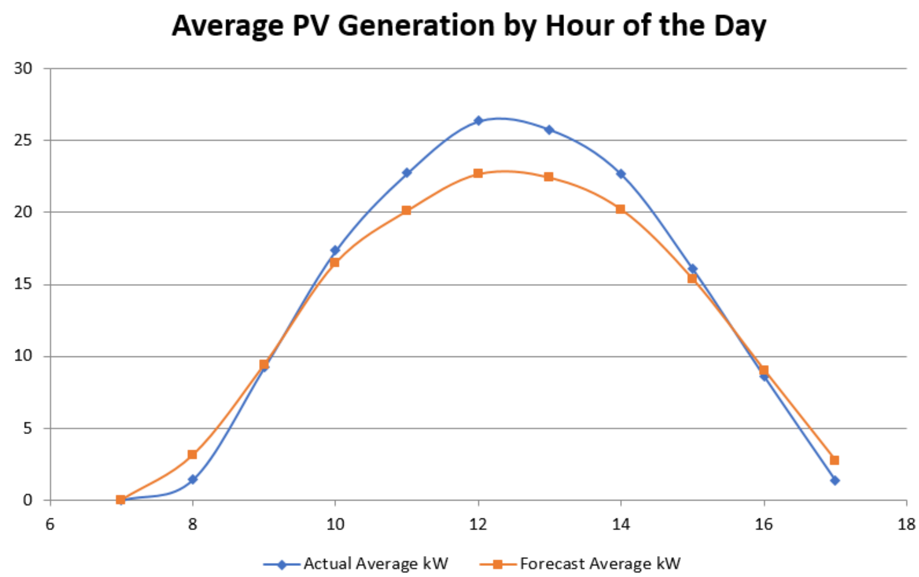


Figure 19: PV Generation Forecast vs Actuals – 17 DERMS PV Sites 11/8/17-1/3/2018

The DERMS ADMS vendor created a 24 to 48-hour short-term load forecast at the feeder head level using an hourly linear regression model that incorporated PG&E's solar forecasting, weather, load patterns, corrections based on recent data, and filtering. This forecast was updated hourly and integrated with the ADMS power flows to allocate those forecasts at every point along the feeders.

MAPE was used as the metric to compare the DERMS forecasts to the actuals. Details of this analysis can be found in Section 18 – Appendix showing the difficulty in forecasting with the YB BESS participating in the frequency regulation market. The analysis also showed the drawbacks of using a percentage as an accuracy indicator, where low loading times in the early morning resulted in the highest MAPE values even if the absolute error may not have been as large.

6.4.3.2 Voltage Forecasting

The load forecast was a direct input into the ADMS power flow calculations to determine the loads and voltages at devices downstream from the feeder heads. The methods used by the ADMS vendor for voltage at the substation were difficult to implement given the telemetry available from PG&E, causing reduced accuracy for voltage forecasts. The voltage forecast could be improved by including the impacts from transmission unbalance, distribution reactive power effects, and historical SmartMeter voltage data. The power flow model assuming balanced voltages for the substation transformer LTC controller did not generally match field observations as shown in Figure 20 for a 24-hour snapshot.

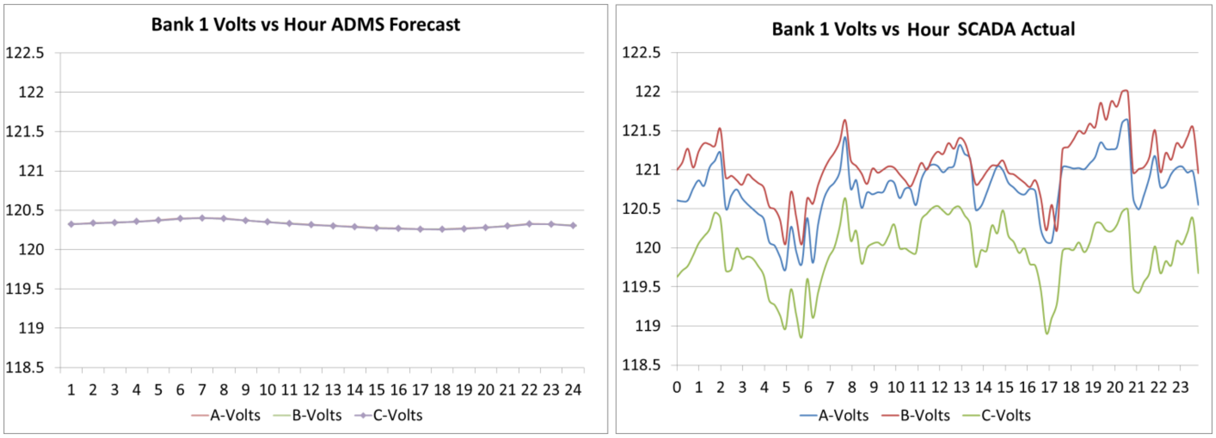


Figure 20: Voltage Forecast vs Actuals – 24-hour Snapshot

6.4.3.3 Forecasting Dependencies

For all forecasting applications (and real-time power flows) there is a need to ensure proper failsafes in the event that there are abnormal conditions or issues with the data feeding the engine.

Field switching is one area that can impact the load forecast as it can either nullify historical load or change the devices that need to be monitored and forecasted. One of the feeder breakers went out of service twice during the demonstration. For an extended time, the feeder was abnormally switched through a substation auxiliary breaker. This aux breaker had no SCADA values and therefore could not be used for forecasting and power flows as it was. A workaround was developed to create a calculated load using the bank load minus adjacent circuit loading to approximate the aux breaker load for DERMS.

Data problems are another potential pitfall for more complex systems. For example, an issue was found with the temperature data coming only intermittently to the load forecast engine. The default value for temperature was set to be 65 degrees Fahrenheit in case there was missing incoming temperature data. This was fine for most days in San Jose but led to large forecasting errors during hot days when it would have been most needed (Figure 21). **It is important to properly assess what failsafe mechanisms are in place during potential data loss or data integrity scenarios, especially if actions are taken as a result of these forecasts.**

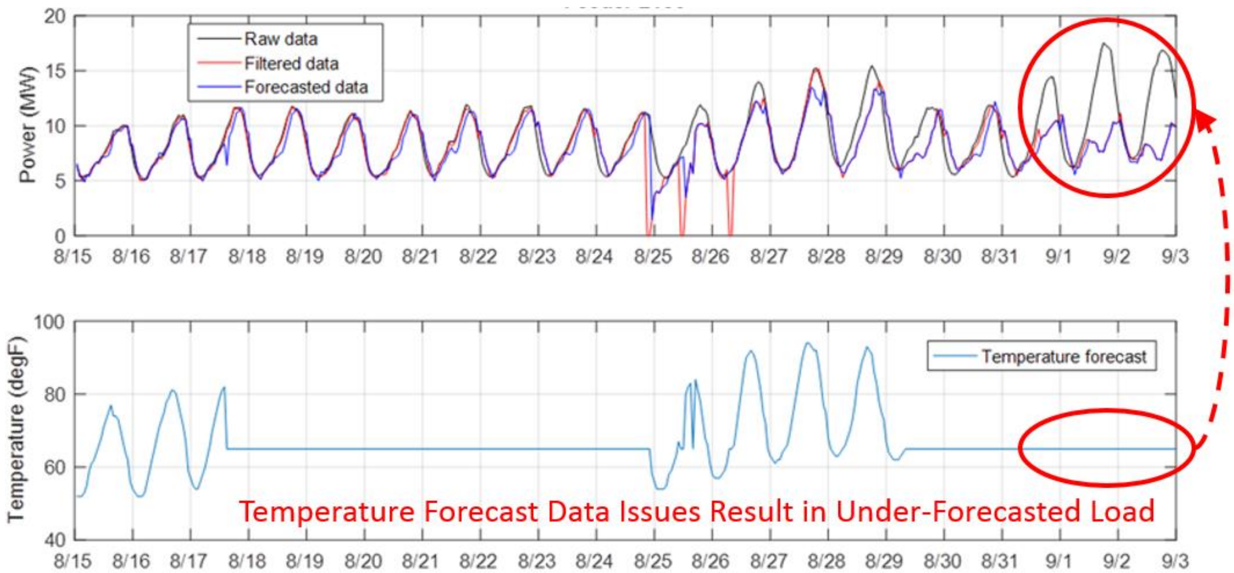


Figure 21: Impact of Intermittent Temperature Data on Load Forecast

The forecasting methods applied during the DERMS Demo are not necessarily those that would be implemented in a production system. However, the learnings and results provide a good baseline from which to progress and improve functionality. The accuracy of forecasting will become increasingly important as Operations and potential Market Functions begin to rely on it to a greater extent. Further development is needed in this area as reliance on forecasting grows.

6.4.4 Aggregator Flexibility Forecasting

In addition to the utility forecasts, DER aggregators also forecasted their flexibility for use in the DERMS optimization). Similar to utility forecasting, there is room for improvement, and **it is expected that aggregator forecasting will advance over time as the value for these types of services increases.** It should be noted that there were no penalties for errors in the reported flexibilities for the DERMS Demo. Vendors would likely improve the processes and accuracy of their flexibilities using learnings from this demonstration for any future production system where the consequences of inaccuracy are greater. The aggregators were both able to respond appropriately to dispatch requests from the DERMS in the demonstration.

The storage-only assets faced challenges coordinating their flexibility algorithms with their local demand-charge management schemes and non-export interconnection limitations (Section 0 - Appendix).

Combined solar and storage residential assets faced different challenges related to solar forecasting and considerations in the dispatch of a DC-coupled PV and storage system (Section 20 - Appendix). For these particular residential PV and storage assets, the battery was idle if not getting commands from DERMS which simplified the flexibility forecasting.

Unlike solar forecasting where a certain generation output is projected in time, a subtlety of storage flexibility forecasting is that it provides an initial state of charge and bounds for a dispatch that an entity like a DERMS needs to adhere to and manage when creating a dispatch. This provides mature energy storage vendors the ability to take actions to prepare for a future dispatch, or take actions to correct for potential errors in the forecast. However, dispatches in the immediate future where there may not be enough time for correction could be more affected by forecasted errors.

7 Distribution Services: Project Activities, Results, and Findings

7.1 Overview

PG&E envisions two primary types of DER dispatches through DERMS to provide distribution services (as described in Section 3.1.2) and enable DERs to be good citizens of the grid:

- **Constraints (Do No Harm):** If there are limitations on the distribution system where unbridled DER actions could cause issues for customers and the system, then the DERMS would impose upper and lower constraints on the output of DERs. This would allow the DERs to act independently provided they stay within the given constraints.

- **Active Management:** If there are issues on the distribution system that could not be mitigated via DER constraints (for example, issues caused by loads and DERs not under the control of the DERMS system), then a DERMS would call on available DERs to mitigate the issue to prevent customer and system issues.

It is assumed that management of DERs is preferable to the potential hazards or outages that would occur if actions were not taken. **Any DER actions would be used in concert with other tools the utility has available including utility device settings, switching, or additional infrastructure to provide a least cost-best fit solution.** Depending on the issue, it may take one or all of the available tools to resolve issues, with a focus on using the most efficient path possible.

PG&E successfully demonstrated the technical feasibility that a DERMS paired with an ADMS can identify and mitigate real-time and forecasted distribution capacity and voltage issues using a combination of DER constraints with active and reactive power dispatches. Plans were dispatched in both day-ahead and hourly ad-hoc schedules to mitigate real-time and forecasted events.

7.2 Technical Development and Methods

Much of the underlying data driving the DERMS distribution services was based on the ADMS power flow results discussed in Section 6 – Situational Awareness. **The ADMS drove the calculations of real-time and forecasted electrical grid needs and DER sensitivities (V/kW, V/kVAR, A/kW) to determine where there were specific voltage or capacity needs and the effectiveness of a particular aggregated DER to address those needs** (Section 13 - Appendix).

Because the demonstration feeders did not have actual grid needs in the field, the general approach for testing the DERMS system was to manipulate the existing capacity or voltage limits in ADMS at device locations based on the present or forecasted loading or voltage levels. This would trigger the ADMS and DERMS into sensing there was a violation to mitigate. For example, to mitigate a capacity overload on a switch having an actual load limit of 600A, if the forecasted or real-time load was found to be over 100A, the load limit on the switch was overwritten to be 100A. This was tested under both the as-built system and the as-operated system to confirm that DERMS could operate under any abnormal switching conditions in the field.

The DERMS provided Operators with a dashboard showing the existing and forecasted issues, as well as three types of DER dispatch plans: Day-Ahead kW, Hourly Ad-hoc kW, and Hourly Ad-hoc kVAR (Figure 22).

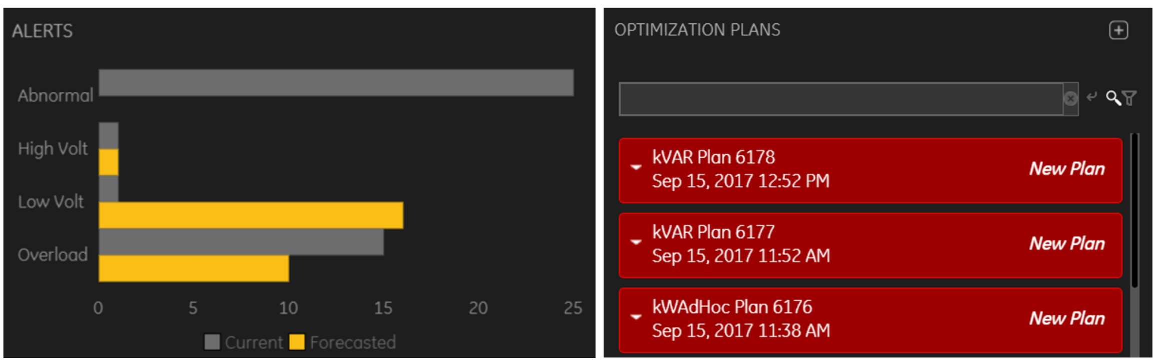


Figure 22: Alert and Optimization Dashboards

The actual dispatch of DERs was based on a least-cost optimization. The DERMS Demo did not attempt to determine the underlying value of distribution services, nor did it specify how distribution services should be enabled as these are being explored separately through the DRP and IDER Proceedings. Therefore, the costs used in the optimization were geared toward eliciting a desired response rather than based on trying to determine actual valuation in the market.

In general, the optimization used costs for violations, costs for using a particular DER, DER sensitivities to the violations, and specific constraints including limits, ratings, available flexibilities, and battery state of charge. For the purposes of proving distribution services, the costs of distribution capacity and voltage violations were made very high (e.g. $10,000/kW and $10,000/Volt) to prioritize mitigating distribution issues over DER costs. Further discussion of the least cost optimization and the running of the day-ahead and ad-hoc markets is in Section 8 – Market Operations.

While possible for the DERMS to determine violations and optimizations for any point in the system, it was decided that the team prioritize specific locations based on reasonable aggregation zones, analysis locations, and available telemetry to reduce the computational burden on the system. These locations, called flow gates (orange boxes in Figure 23), were at specific known SCADA devices on the feeders. In addition, these devices were field verified for accuracy to help in the analysis.

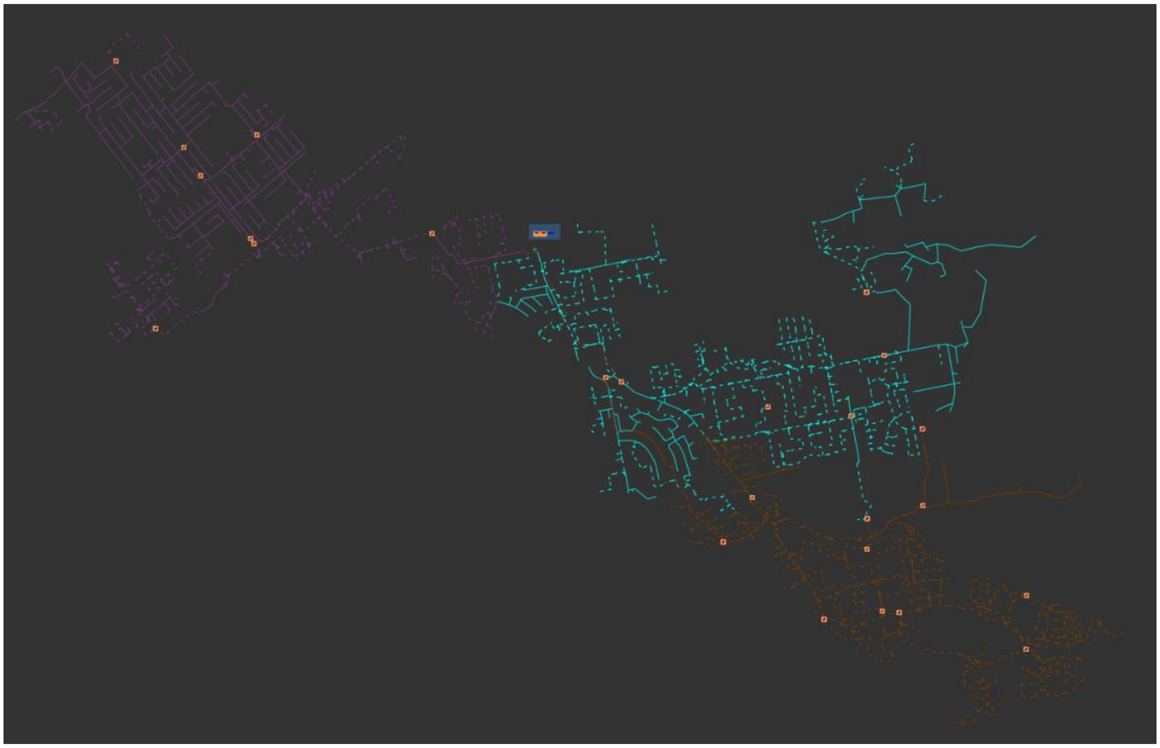


Figure 23: Flow Gate Locations

Although the amounts of BTM DERs under control were relatively small, the DERMS algorithm would use all available capacity to mitigate issues to the extent possible. Therefore, even if a violation wasn't eliminated, its magnitude would be reduced. The participating DER aggregators were also evaluated in their ability to respond to the DERMS dispatch requests.

7.3 Challenges

7.3.1 DER Capacity and Availability

As described earlier, there were challenges in obtaining targeted DER deployments on the demonstration feeders. Therefore, the resulting DER capacity available to DERMS, specifically from aggregators, was relatively small when compared to trying to solve capacity or voltage issues. Fortunately, the PG&E-owned YB BESS provided a significant amount of kW and kVAR to show potential impacts on the system under larger penetration scenarios.

Voltage was even more difficult to impact than capacity, with the DERs having a relatively small voltage sensitivity compared to their kW or kVAR output. This meant that larger amounts of DERS were required to substantially impact voltage.

When dealing with non-three-phase customers, like residential installations, phasing becomes more important. Customers may be unequally distributed among phases where the total capacity is sufficient to resolve an issue, but the uneven dispatch would not actually solve the issue or could even create new issues like unbalance.

Recommendations:
In the near-term, there may be difficulty obtaining enough DERs in terms of sufficient locational value, volume, availability, and dispatch assurance to offer grid services. **Targeted grid services projects in the future must consider the difficulties of timely acquisition and deployment of enough willing DER customers to significantly impact the system.** Therefore, DERs should be viewed as one tool in conjunction with existing utility mechanisms for capacity and voltage issue mitigation to provide customers with a least cost-best fit solution.

7.3.2 Accuracy of Real-Time and Forecasted Values

The importance of the foundational evaluations done in Section 6 – Situational Awareness, were made apparent during the actual mitigation of issues. The ability to efficiently mitigate issues depends on how well the system can initially identify those issues and calculate the requirements of dispatching DERs to address the violations. Forecasting of possible violations, and positioning of DER assets (e.g. state of charge management) relies heavily on accurate models for loads, generation, and battery state of charge. If violations were either over reported or under reported, that directly affected the amount of DERs dispatched. Moreover, mitigation success is also dependent on the ability for aggregators to provide accurate real-time and forecasted flexibilities of their assets.

Recommendations:
Significant investment is needed in the underlying data, modeling, and forecasting that underlie advanced applications like DERMS. PG&E is proposing these types of investments through their IGP strategy and 2020 and 2023 GRC filing.

7.3.3 Optimization Complexity

The complexity of the analysis and optimization performed by the DERMS system required certain simplifications to allow it to produce solutions in a meaningful timeframe. Although the DERMS Demo was an MVP, the combined modeling and optimization solution execution times were exceedingly long, almost reaching an hour at times. Future DERMS systems will need to rely on methods and algorithms to speed processing times. The following are some simplifications made for this particular project.

7.3.3.1 Static Aggregations

DERs were divided into static aggregation zones, with each zone having multiple ADERs as described earlier. For the purposes of simplifying the calculations for this DERMS MVP, the impacts of all DERs within an ADER were consolidated to one point on the feeder, rather than distributing those impacts among the specific locations of each DER.

Recommendations:
While suitable for an MVP, more dynamic capabilities for aggregation zones and ADER contributions are expected to be required at scale under more frequent switching conditions (See Section 13 - Appendix).

7.3.3.2 Linear Estimations

The optimization used a linearized power system model to determine the required DER capacity for mitigating violations. For example, capacity and voltage sensitivities (e.g. A/kW, V/kW, or V/kVAR) were calculated at one point in time and then scaled based on different types of dispatches. While this provided relatively good results, there were some instances where the linear approximation got close to resolving a violation but did not completely mitigate it, even if there was DER capacity remaining.

Recommendations:
Small scaling factors were put in place to slightly modify the sensitivities to ensure issues were fully mitigated. This provided adequate coverage for the approximations of the linear estimations.

DERs with very small sensitivities should be excluded to avoid nuisance dispatches. For example, the medium voltage sensitivities for many aggregated DERs were very small, meaning that even if they were fully dispatched the voltage on the primary feeder would not see a measurable change. Therefore, it was not worth the cost or wear on the device to dispatch it at all.

7.3.3.3 Valuation of Violations

The DERMS Demo did not attempt to determine the underlying value of distribution services, nor did it specify how distribution services should be enabled. Therefore, violation costs did not reflect real market costs.

Recommendations:
There needs to be continued involvement by diverse parties in the policy and regulatory forums that are shaping the valuation discussion, including the DRP and IDER Proceedings.

Additionally, when optimizing both capacity and voltage, the sensitivities for voltage (V/kW) are generally lower than those for capacity (A/kW) when addressing a grid need. Therefore, **with equal cost weightings, capacity violations are inherently prioritized.** Thus, valuation of capacity and voltage will need to be adjusted depending on the goals of the optimization.

7.3.3.1 Separate Active and Reactive Power Optimizations

The DERMS Demo provided separate active power and reactive power optimizations to simplify the process and calculations for the DERMS vendor. This led a non-holistic approach to DER management that can introduce inefficiencies in the optimizations based on the interplay between active and reactive power dispatches.

Recommendations:
There should be a single combined optimization that considers the impacts of active and reactive power DER dispatches.

7.3.3.1 Limited Smart Inverter Controls

The DERMS Demo limited the types of smart inverter controls to on/off, setting active power, and setting power factor. While adequate for the DERMS Demo, power factor control in particular made it difficult to dispatch reactive power effectively.

Recommendations:
A direct kVAR dispatch would be simpler and more efficient than power factor controls, especially if there is a need for reactive power only dispatches.

7.3.4 Rules of Operation

Consensus among parties regarding the rules of operation are important, especially when creating the new interactions required for the DERMS Demo. Even with existing standards, interpretation can differ among vendors. Table 8 provides a few example situations that were approached differently by vendors during the DERMS Demo prior to clear rules being established.

Table 8: Differing Approaches to Operational Rules

Scenario	Differing Approaches
Dispatch Request Beyond Present Capabilities	• Dispatch to maximum of capabilities • Cancel entire dispatch
Overlapping Schedules	• Layer dispatch schedules with latest schedule having priority • Cancel any previous dispatch schedule
Overlapping Control Modes	• New control mode layered within capabilities over existing mode (e.g. active with reactive power dispatch) • Only most recent control mode allowed, even if asset could support both
Schedules Arriving After the Start Time	• Dispatch schedule for remaining amount of time • Do not dispatch schedule
Sign Conventions	• Generator sign convention • Load sign convention
Rating Provided	• Full Rating (including any reserve that may not be able to be dispatched) • Available Rating

Flexibility Reporting	• Raw Flexibility: kWh • % Flexibility: Percent of capacity (Needs to incorporate or send potential changes to overall capacity arising from equipment issues or ADER changes)

Recommendations:
Industry should work towards standardizing rules of operation in the long-term, but in the near-term, clear documentation is required to establish rules among parties, similar to what was created for the DERMS Demo. In addition, it was found that clear examples of the expected functionality should be included, as there could be different interpretations of the written rules. Clear test procedures are also needed to ensure compliance.

7.3.5 DER Capabilities

DER capabilities also have room to grow based on issues faced during this project. These types of challenges can be overcome as technology matures, but they provided a good backstop to ground the project in the current state of the industry.

7.3.5.1 Solar + Storage

The residential solar plus energy storage setup used in this demonstration could not provide full flexibility in the load direction, to both curtail solar and simultaneously charge from the grid. If PV was generating, the battery would only charge to its rating minus the PV production. If the PV production was more than the rated charging ability, they would just curtail the PV to zero, and have no charging of the battery. There were also some issues with the vendor being able to use the full flexibility if more than one battery was installed at a residential location.

Recommendations:
To provide full flexibility, solar plus storage assets should be able to operationally run the spectrum of full load (charging the battery and curtailing all solar generation) to full export (solar generation plus export from the battery). However, this needs to be in compliance with any interconnection requirements, such as non-export, and coordinated efficiently with storage to minimize any solar curtailment. Additionally, the ability for inverters to properly manage multiple assets if DC-coupled should be properly verified before providing grid services.

7.3.5.2 Delta-Gen and Curtailment Values

DERMS dispatched active power through a delta-gen command that set the DER control at an incremental or decremental delta generation level as a percentage of the nameplate rating of the aggregated DER. Dispatching a delta-gen command was difficult for the solar providers because smart inverters presently cannot tell the max solar power available if they are being curtailed. This causes issues not only for reporting actual curtailed amounts, but for also dispatching commands like delta-gen, which ask for a decrease from the non-curtailed generating capabilities. One vendor implemented a method to periodically check the max power output as shown in Figure 24. While this method was acceptable for the MVP, there are definite drawbacks in under and over dispatch, especially during times of high variability.

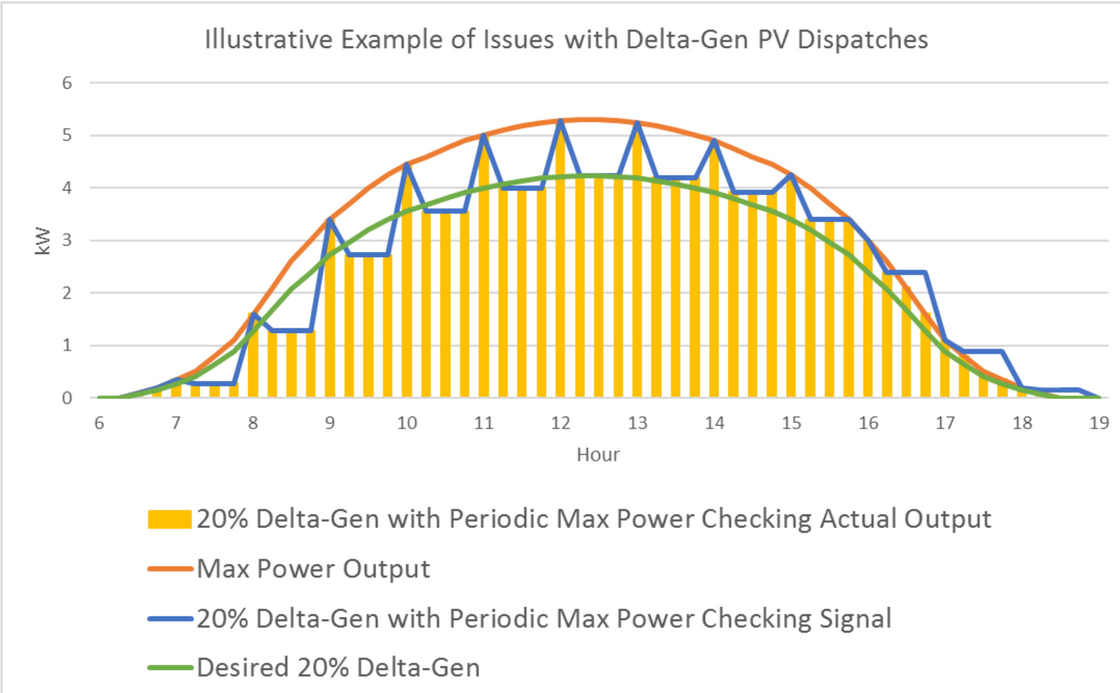


Figure 24: Issues with Implementing Delta-Gen for PV

Recommendations:
Inverter manufacturers and DER developers should work on developing accurate and standardized methods to determine max power capabilities for solar generation under curtailed states. While helpful for dispatches like delta-gen during this demonstration, it is also important for accurately determining the energy and financial impacts of curtailment commands.

7.3.5.3 Smart Inverter Standards

The latest IEEE 1547-2018 standard[33] does not call for the full potential reactive power capability of smart inverters as a minimum requirement. For example, there are only two performance categories (A and B as shown in Figure H.3 of IEEE 1547-2018) defined in the standard, and neither ask for a minimum reactive power capability of more than 44% of the device volt-ampere rating, nor do they require any minimum kVAR capabilities when providing active power absorption. The application of reactive power for distribution services would most likely require

[33] https://standards.ieee.org/standard/1547-2018.html

capabilities outside of the minimums established in 1547-2018. Therefore, if a DER provider or utility wanted to certify a particular inverter beyond these minimum capabilities, they would need to establish a separate (non-standard) certification criteria and process for such functions. For storage assets this would include any reactive power output during charging scenarios.

Recommendations:
Standardized performance categories should be expanded to include greater capabilities for reactive power dispatch of inverters. This is especially apparent for storage, where reactive power dispatches should include the active power absorption quadrants. This would negate the need to establish separate certification criteria and processes for such functions if such assets are expected to provide grid services in the future.

7.3.6 DER Communications

7.3.6.1 Communication Standards

As mentioned in Section 5.3, there was no clear-cut communication standard when the project began. IEEE 2030.5 was chosen as the most practical, but custom extensions were still required to fully implement the project use cases.

Recommendations:
The DERMS Demo was ahead of the industry, and thus customizations like those required for the project were expected to be ahead of existing standards. PG&E and the project vendors are working with various standards bodies and industry leaders to understand these extensions and their justifications to determine what should be included in future iterations of applicable standards.

7.3.6.2 Communication Uptime of DER Assets

For the DERMS Demo, the aggregator was responsible for all communications to the individual inverters. While communication between PG&E and the aggregator was robust, the individual DER asset communication uptime needed improvement over the course of the project through various troubleshooting efforts[34]. The aggregator to DER communications was proprietary.

Recommendations:
Some level of communication issues should be expected in the future. It will take a combination of methods to mitigate potential effects including aggregators maintaining sufficient liquidity of

[34] Additional information about DER communications on the demonstration feeders can be found in Section 7.4.4.2 and the EPIC 2.19 final report.

assets to manage dispatch compliance, potentially de-rating of an aggregation, local memory for scheduled functions and data history, etc.

7.4 Results and Observations

7.4.1 Capacity Violation Mitigation

The DERMS Demo confirmed that a DERMS can identify real-time and forecasted capacity violations on the system and provide mitigation solutions given enough available DER active power (kW). Both forward and reverse violations were considered in the day-ahead ask-bid-commit process as well as the ad-hoc hourly simulated markets. Once fully mitigated (or if no issues existed) the DERMS would dispatch based on energy arbitrage to make as much money as possible for the DER provider. Figure 25 shows an example of the before and after analysis of a DERMS dispatch for a capacity (overload) solution.

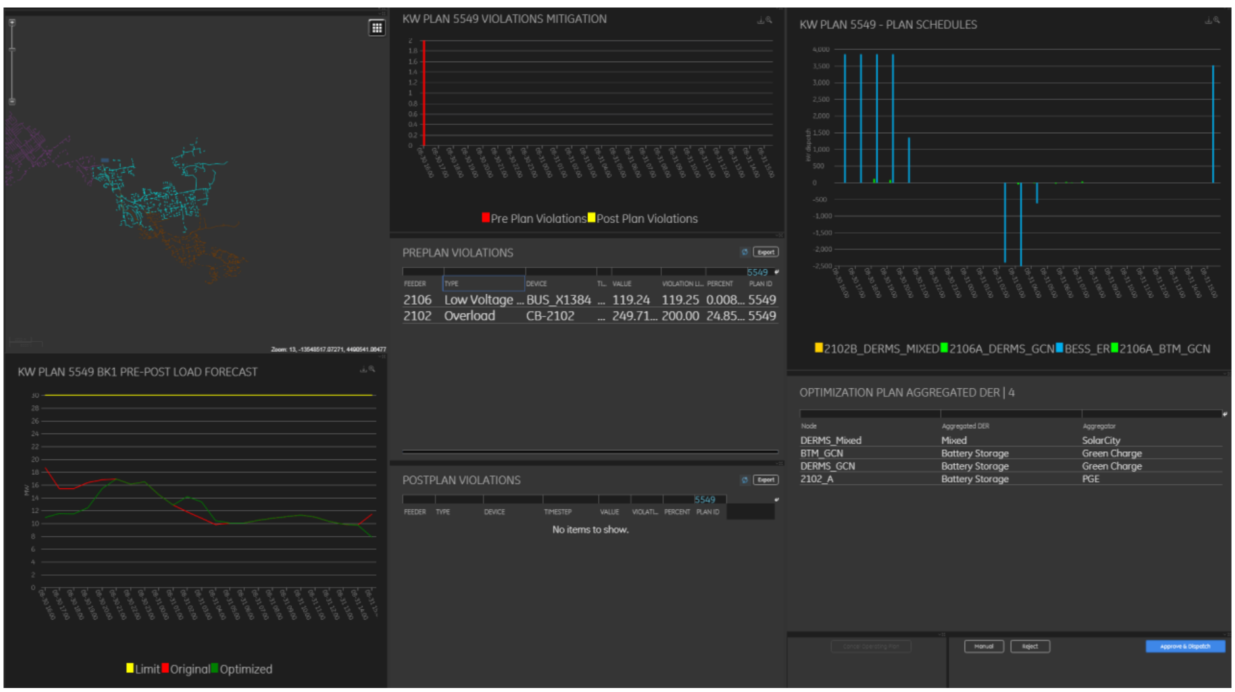


Figure 25: Screenshot of Mitigation Plan from the demonstration DERMS

Among the types of distribution operational constraints, the DERMS was the most effective at detecting and mitigating real-time and forecasted capacity violations. The DERMS effectively alarmed within the 5-minute online power flow run cycles for all types of capacity violations based on the real-time and forecasted calculations. The DERMS consistently mitigated capacity constraints through active power dispatch of available resources while considering nameplate and state of charge constraints. As shown in Figure 26, due to insufficient DER capacity available, mitigation was often just reducing the magnitude of the violation, and not completely resolving it.

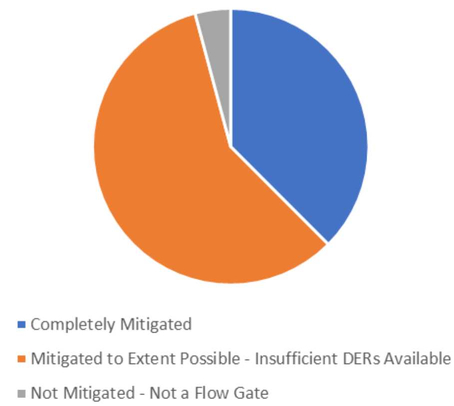


Figure 26: Results of Real-time & Forecasted Forward Capacity Constraint Mitigation Testing

For the purposes of the DERMS Demo, backfeed violations for line devices referred to their thermal capabilities (therefore the forward and backfeed overload magnitude limits were equivalent). Backfeed violations for the substation bank/LTC were configured to alarm for reverse flow (MW < 0) at the bank level. The DERMS Demo was always able to mitigate backfeed violations because the DERMS had control over the only DER capable of creating a backfeed (YB BESS) on the demonstration feeders.

The DERMS also adjusted properly to any new constraints placed on any of the DERs. This helped show the technical implementation of potential de-rating either based on DER provider limitations or grid limitations. For example, the DERMS was given a hard constraint that the YB BESS could not be dispatched beyond 500kW for a particular test. It then updated and lowered its original planned dispatch from 3.9MW to 0.5MW.

The size and location of the YB BESS also allowed demonstration of potential back-tie switching to provide support on an adjacent feeder as shown in Figure 27.

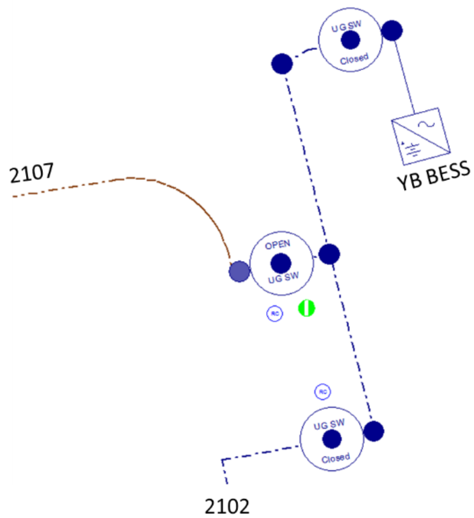


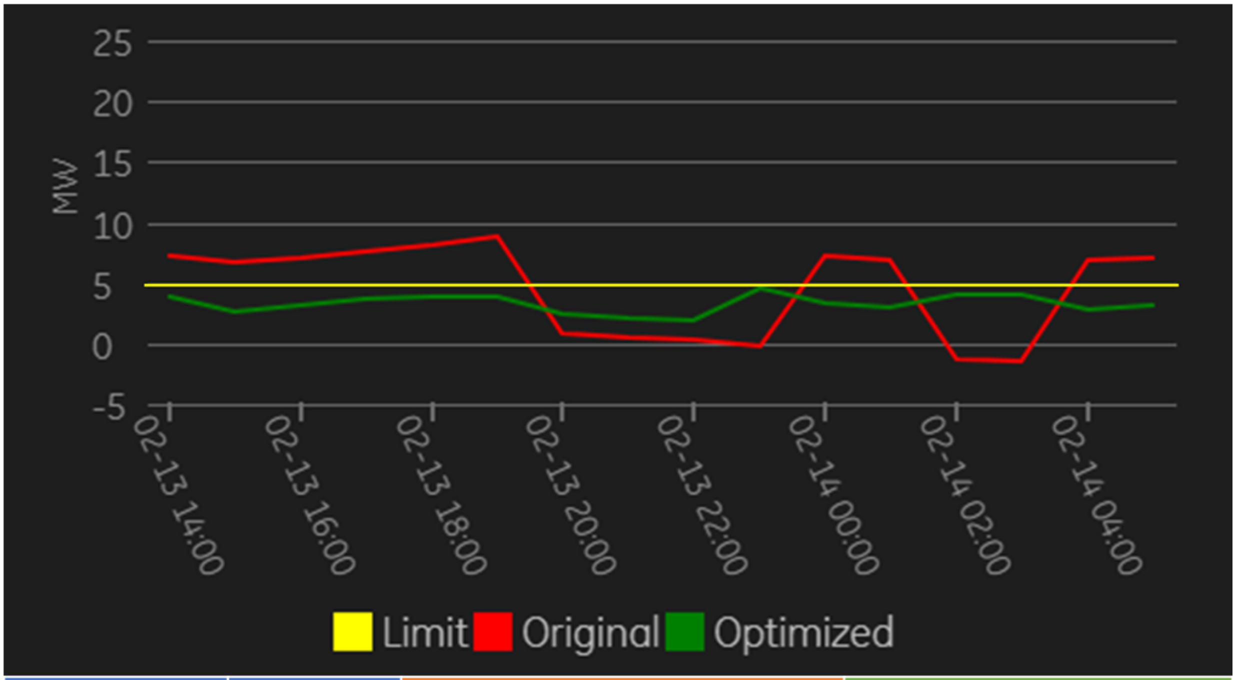
Figure 27: Diagram Showing Ability to Switch YB BESS between Adjacent Circuits

The DERMS successfully mitigated violations after simulating switching operations to move YB BESS to the adjacent feeder. While technically these types of assets could be switched around to help support reliability or resiliency, this demonstration did not evaluate the contracting or coordination efforts to enable that type of functionality.

7.4.2 Voltage Violation Mitigation

The DERMS Demo confirmed that a DERMS can identify real-time and forecasted voltage violations on the system and provide mitigation solutions given enough available DER active (kW) and reactive (kVAR) power. Similar to capacity, voltage violation mitigation via kW was considered in the day-ahead ask-bid-commit as well as the ad-hoc hourly simulated markets. Voltage mitigation via kVAR was only available in a separate hourly ad-hoc market from kW based on the MVP implementation.

The DERMS alarmed within the 5-minute online power flow run cycles for voltage violations based on the real-time and forecasted calculations. The DERMS consistently mitigated voltage constraints through real and reactive power dispatch of available resources while considering nameplate and state of charge constraints. For kW dispatch, the DERMS could solve simultaneous voltage and capacity issues. However, care needed to be taken to create violation costs that overcame the challenge of capacity being inherently prioritized with equal cost weightings as shown in Figure 28.



Violation Type	Violation Cost	Pre-Plan		Post-Plan	
		Count	Cost	Count	Cost
Voltage	$120k/Volt	6	$562,800	0	$0
Overload	$10k/kW	10	$381,690,434	7	$28,101,008
Backfeed	$30k/kW	6	$220,494,163	0	$0
	Grand Total	22	$602,747,397	7	$28,101,008
Percent Cost Reduction			**95.34%**		

Figure 28: Simultaneous Voltage and Capacity Violation Mitigation with Unequal Violation Costs

As discussed in Section 6, there were challenges around the accuracy of the real-time and forecasted voltages. Because the allowable range of voltage is only +/-5% of nominal, on a 120V base this only allows for a 12V range. With potential accuracy in the 2% range (~2.4V), this can have a significant impact within the 12V allowable range.

Whereas system capacity changes have a more direct relation to the output of the DER, voltage impacts can be more influenced by specific circuit characteristics, as well as other devices on the system like LTCs, voltage regulators, and capacitor banks. **Therefore, the DERMS must be able to coordinate with these other systems in real-time to ensure they work together and do not oppose or undermine one another.**

Another complexity of voltage sensitivities, is that DERs will only impact the capacity of the lines directly upstream of them, but can impact voltage of lines upstream, downstream, or even not in line with the DER at all as shown in Figure 29. **Therefore, although the original aggregations were based on topology, it may make more sense for future electrical aggregations to be based on sensitivity, especially for voltage support.**

Figure 29: Modeled Voltage Sensitivity of YB BESS kVAR Dispatch at Multiple Locations on the Demonstration Feeder

7.4.2.1 kW vs kVAR

Given the stated challenges around voltage, **DERMS successfully used both active and reactive power dispatches to mitigate voltage violations to the extent possible given the available DERs.** Voltage mitigation was especially constrained by the limited amount of DER capacity available due to the small and variable V/kW and V/kVAR voltage sensitivities.

The team attempted to measure and calculate the voltage sensitivities at different locations based on the output of the YB BESS as shown in Table 9. Note that calculating the voltage sensitivities from field measurements have errors introduced through the limited accuracy and precision of the SCADA voltage measurements. However, given that sensitivities will vary depending on feeder characteristics and locations, directionally it can be seen that voltage sensitivities can be quite small, especially on stiffer feeders like those in the DERMS Demo.

Table 9: Measured Voltage Changes with Variable kW and kVAR YB BESS Dispatches at Multiple Feeder Locations*

YB BESS Dispatch	Site A	Site B	Site C	Site D	Site E	Site F	Site G	Site H
-1000 kW	-0.54	-0.10	-0.10	-0.32	-0.20	-0.39	-0.21	-0.10
-500 kVAR	-0.87	-0.69	-0.60	-0.52	-0.70	-0.56	-0.36	-0.60
+500 kVAR	0.92	0.67	0.67	0.44	0.66	0.60	0.40	0.59

*These measurements were taken within the same hour on the same day with varying YB BESS dispatch. No changes in LTC position or significant capacitor bank VAR change was observed during this period.

Furthermore, as can be seen in Table 9, it was also observed that kVAR seemed to have a greater effect on voltage than kW dispatches on the demonstration feeders**. While the specific sensitivities will vary depending on circuit and DER location, certain locations may be more conducive to kVAR dispatch for resolving voltage issues.** This is a potential avenue for DERs to realize additional value, where a DER can simultaneously provide kVAR, which minimally impacts the state of charge (SoC), and kW, which is the primary source of DER value and revenue.

While kW and kVAR dispatches were separated in the implementation of the MVP demonstration, future optimizations should combine both into a single optimization for both capacity and voltage. Figure 30 shows how **the DERMS can mitigate the voltage rise at a nearby field device caused by a kW dispatch by using available kVAR at the same time.**

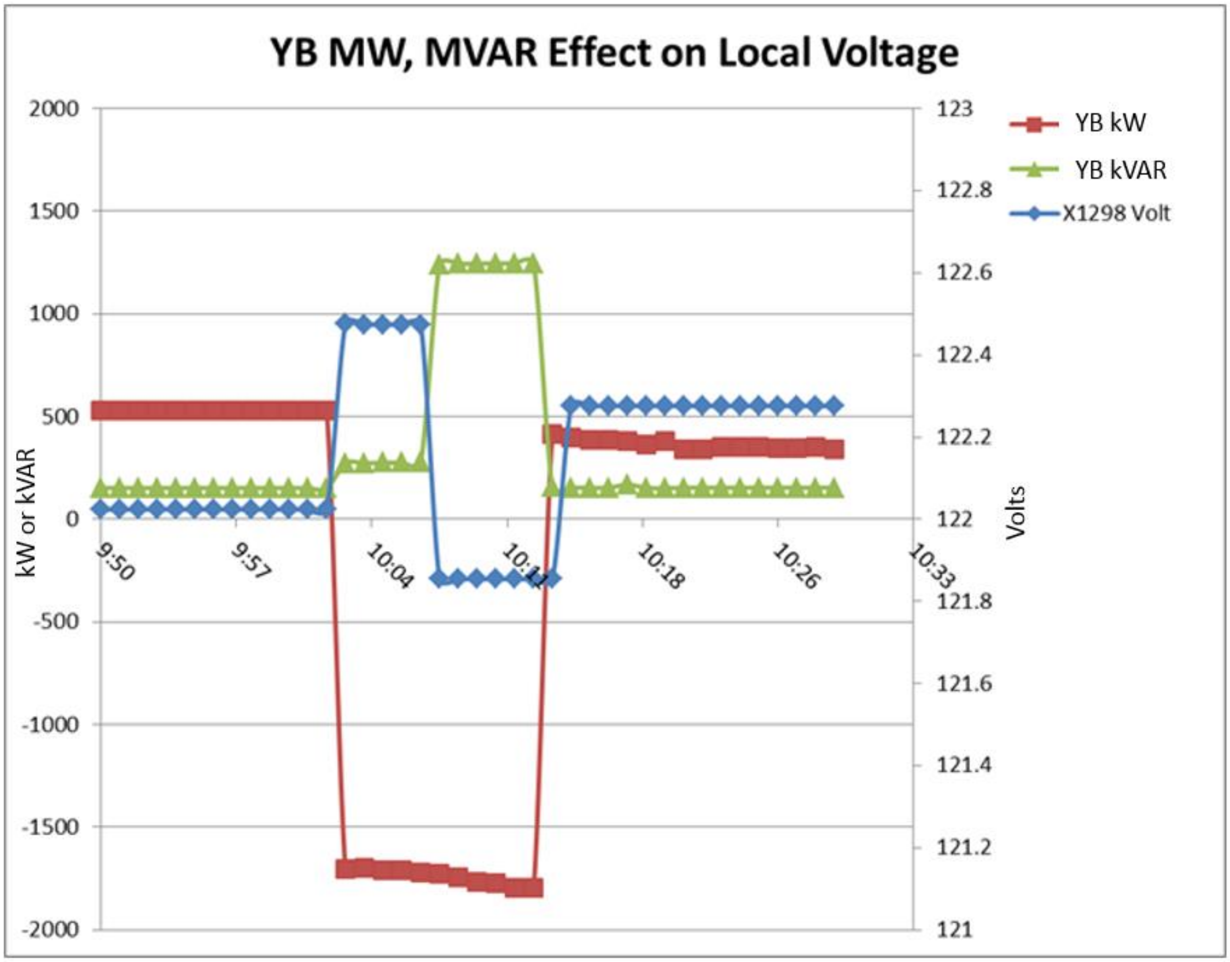


Figure 30: Using kVAR to Mitigate the Voltage Effects of a Simultaneous kW Dispatch

7.4.2.2 kVAR vs Power Factor Dispatch

The DERMS Demo used fixed power factor to dispatch VARs to the two aggregators primarily because it was already specified by the California Electric Rule 21 SIWG as a Phase 1 function.

Power factor control was found challenging because the reactive power output depended directly on the active power output. A kVAR only dispatch was not possible via power factor, even though assets like storage could technically provide it. This meant available assets would be automatically excluded for a reactive power dispatch if they had no active power output. Furthermore, particularly for solar generation, the VAR output when using power factor was less consistent if there was variability in the kW production.

Direct kVAR dispatches would have provided more predictable control over assets regardless of their active power output. While power factor control does have a place in maintaining efficiencies and system compliance, it can also significantly limit the potential output of an asset if required to be maintained within a particular power factor (e.g. ±0.9). Therefore, coordination with existing utility controls and equipment will be needed even if using direct kVAR dispatches to ensure compliance with system power factor needs while functioning within the kVAR capabilities of a particular DER.

7.4.2.3 Coordination with Grid Devices

Another consideration with kVAR and kW control for voltage is the coordination with substation LTCs, voltage regulators, or capacitor banks that may counteract or potentially even amplify what the DER dispatch was trying to achieve. Similarly, because power factor at the substation must be maintained to support transmission, coordination is needed to ensure any DER kVAR dispatches do not put the substation out of compliance for power factor.

Another potential impact from kVAR dispatch is the creation of harmonic resonance conditions on the feeder that may exacerbate harmonic problems for customer equipment. While further study is needed in this area, testing of the YB BESS at different kVAR levels did not show any particular harmonic issues for the demonstration feeders.

7.4.3 Abnormal Topology

The tight integration of DERMS with ADMS made handling of abnormal topology fairly seamless for both voltage and capacity mitigation, with field changes being automatically processed and included in calculations in real-time. Figure 31 shows an example of mitigating a forecasted backfeed violation at the substation bank after field switching.

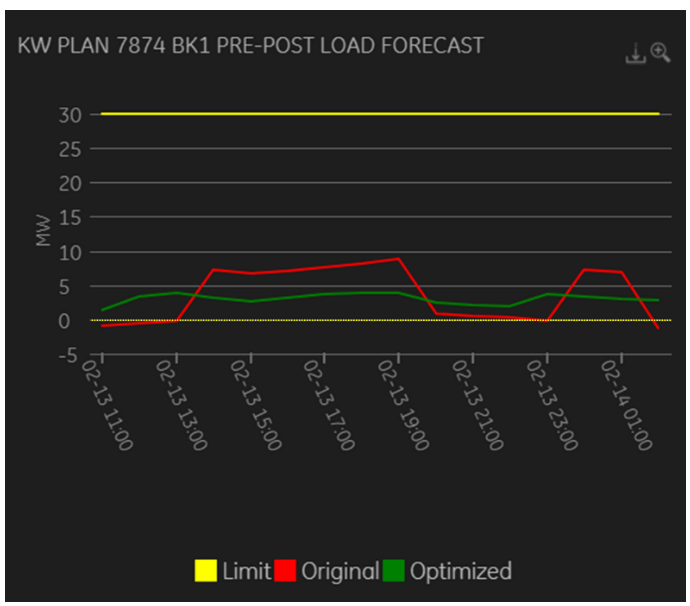


Figure 31: Forecasted Substation Bank Backfeed Mitigation after Switching

7.4.4 Aggregator Analysis

The availability and reliability of the underlying DER assets are critical to the DERMS process. This requires both accurate input data to let the DERMS know flexibility (Section 6.4.4), capabilities, and constraints, as well as confirming output based on DERMS commanded dispatches or constraints. Furthermore, communications reliability is important to ensure the DERs can be called on when needed.

7.4.4.1 Aggregator Response Confirmation

As part of the commissioning process for the aggregator interface, PG&E, the DERMS vendor, and the 3rd party aggregators jointly tested multiple types of exchanges including controls, flexibility forecasts, and SoC to confirm accuracy and that aggregator responses were properly received and scheduled. The team used aggregator vendor portals to remotely monitor DER assets to compare with the aggregator interface. As this was a new process, there were initial hurdles, but by the end of testing the aggregators were able to reliably dispatch assets in accordance with DERMS requests.

7.4.4.2 Aggregator Communication Analysis

The assets used in the DERMS project were shared among three EPIC projects: 2.02 DERMS, 2.03A – Test Smart Inverter Enhanced Capabilities – Photovoltaics (PV), and EPIC 2.19 – Enable Distributed Demand-Side Strategies & Technologies. Communication up-time was tracked for the field DER assets for a period of four months for the demonstrations. To assess the communications reliability from a DERMS perspective, the communications up-time data was split into an hourly analysis per month. Since the DERMS created an optimization plan every hour, the communication up-time was analyzed for one-hour advance availability for communicating the dispatch schedule to the DER. Communication reliability analysis was combined for all the assets of a given aggregator.

One aggregator's communication uptime improved after early troubleshooting. The other aggregator had between two and three assets which were consistently having communication problems due to reliance on residential customer internet connections. Additional information about DER communications can be found in the EPIC 2.19 final report[19 above].

Figure 32 shows the results of assessing the availability of each aggregator's DER assets for communication at any point in the previous hour or previous 12 hours.

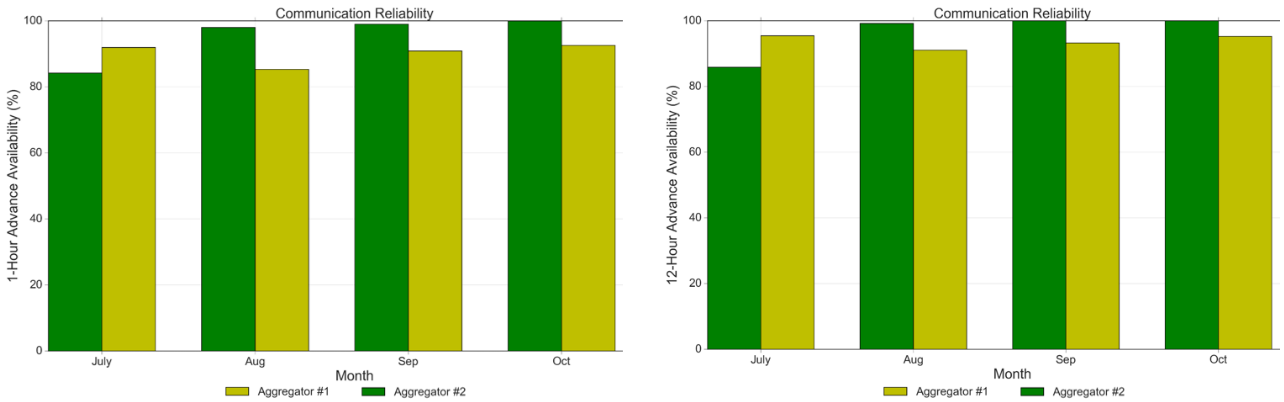


Figure 32: 1-Hour Advance and 12-Hour Advance Availability for Aggregator Asset Communications

8 Economic Optimization: Project Activities, Results, and Findings

8.1 Overview

The DERMS Demo explored the ability of individual and aggregated DERs to realize value via multiple avenues. By materially testing MUA across programs and DER providers, this demonstration furthered the discussion around potential challenges to address in forums such as the CPUC's Energy Storage MUA Working Group and upcoming research projects. The DERMS Demo focused on the technical utilization of DER resources across markets, while the DRP and IDER proceedings continue to explore the additional complexities related to distribution grid service valuation. **The learnings around MUA highlight a need for transparency, coordination, and rules across programs to ensure proper prioritization and equitable settlement.**

8.2 Technical Development and Methods

8.2.1 Least-Cost Dispatch

The DERMS vendor combined a QSTS-enabled offline power flow with a commercial MILP solver to create the least-cost optimization for distribution services. The optimization was coordinated with the day-ahead and ad-hoc distribution market processes (Section 0 - Appendix) created for the project, and ran autonomously via the aggregator interface, with dispatch plans being approved by the DERMS Operator. While this approach was suitable for the DERMS MVP demonstration, given adequate trust in the system, the processes for optimization and dispatch are likely to be automated in the future.

The least-cost optimization took into consideration various parameters (Table 10) to create an achievable dispatch.

Table 10: DERMS Optimization Parameters

Costs	Capabilities	Constraints
Offer Prices from DERs Wholesale Prices Violation Penalties Wholesale Deviation Penalties SoC Violation Penalties	DER Flexibility Capacity Sensitivities per Device Voltage Sensitivities per Device PV Forecasts Battery Starting Charge Levels Battery Charge / Discharge Rates DER Efficiencies	Violation Limits Vendor Based PV + Storage Dispatch Rules SoC Constraints SoC Hand-off Levels Non-DERMS Operating Plans Interval Length

The DERMS optimization had to take aggregator flexibility and pricing into account including the initial SoC for storage and any known dispatches. The DERMS was responsible for managing the SoC to fulfill any new dispatch requests given the initial and required ending SoC from aggregators.

The costs of violations and offers were manipulated to confirm that DER dispatches would change appropriately based on the least-cost for both the day-ahead and ad-hoc markets. In the absence of violations, the DERMS was designed to perform energy arbitrage, using the forecasted wholesale market pricing information and costs to operate DERs to make as much money as possible for the DER provider.

8.2.2 MUA

The DERMS Demo looked at various situations to determine potential priority needs for either constraint or active management controls between distribution and wholesale services, as well as potential settlement and other coordination issues. As discussed in Section 7.1, PG&E envisions two primary types of DER dispatches through a DERMS to prevent or mitigate issues on the distribution system: constraints and active management.

While most of the DER dispatches in the previous section for distribution services were based on active management, it is possible that a majority of the “controls” from a utility will be constraints, especially if trying to avoid infrastructure investments to increase DER hosting capacity. Constraints allow the DER operators to participate in the markets of their choosing while remaining good citizens of the grid.

For example, via the interconnection process to avoid costly infrastructure improvements, the YB BESS has specific hours in which it is de-rated to limit discharging to 2.0 MW between 23:00 and 09:00 year-round and to limit charging to 2.5 MW between 15:00 and 23:00 from May 1 to September 1. While these types of interconnection-based constraints are very infrequent today, PG&E is exploring how this may be expanded through upcoming research projects.

8.2.2.1 MUA Framework

Only the YB BESS and the aggregated commercial BTM energy storage assets were used for testing MUA. Similar to leveraging the other EPIC projects for the installation and location of

DERs, the DERMS Demo built off existing projects to implement MUA. Figure 33 shows how the project was set up to provide distribution services via the EPIC 2.02 DERMS Demo, and wholesale market participation via the Supply Side II DR Pilot and EPIC 1.01 Storage for Market Operations. For wholesale participation, an independent scheduling coordinator was used for the 3rd party DER aggregator, while PG&E's STES team acted as the scheduling coordinator for the YB BESS. The YB BESS generally participates in the wholesale ancillary services market as a front of the meter (FTM) resource using CAISO's non-generating resource (NGR) model originally implemented via EPIC 1.01.

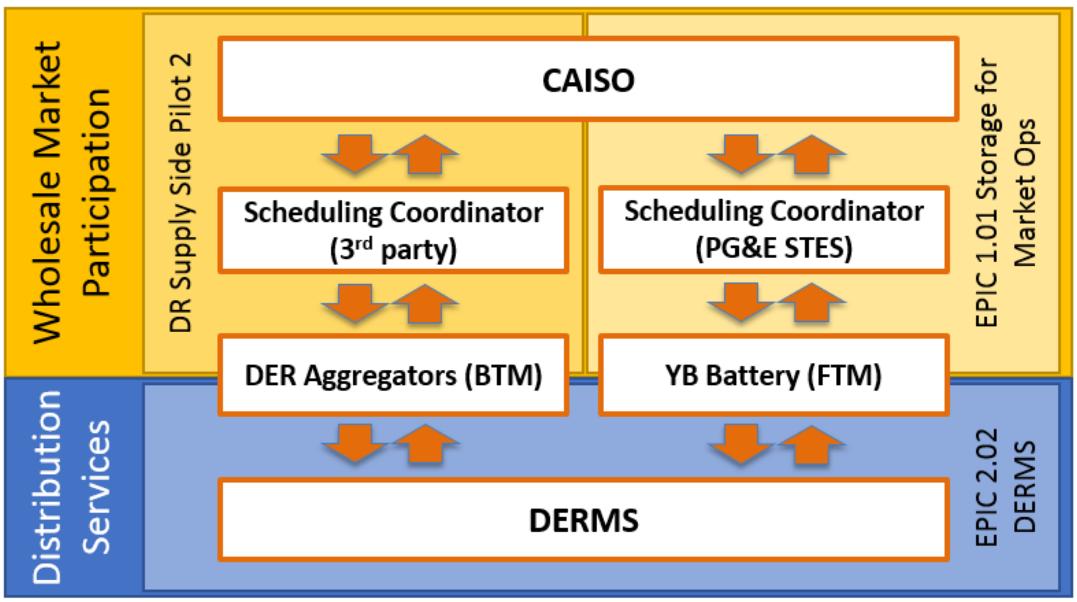


Figure 33: Overview of Demonstration Setup for MUA

The DERMS team coordinated with STES to schedule hours for DERMS testing, manage battery states of charge during hand-offs, and communicate any DERMS constraints for testing, estimated wholesale prices, and advisory day-ahead wholesale market participation schedules.

The BTM aggregator assets consisted of three 120kW batteries located at three different commercial customer sites. The primary intent for these batteries was customer demand charge management using the aggregator's proprietary peak shaving algorithm. To mimic wholesale market participation, these three batteries were aggregated into a single DER resource and were bid into a simulated market as a Proxy Demand Resource (PDR)[35] via PG&E's Supply Side II DR

[35] PG&E supports the use of CAISO's PDR / DR Provider Agreement (DRP-A) rather than NGR/DERPA to enable BTM DER participation into CAISO markets for its relative maturity as a wholesale market

Pilot (SSP II), with additional simulated load increase dispatches based on PG&E's Excess Supply DR Pilot (XSP)[36]. The three customers were enrolled in the SSP II via the asset vendor/aggregator.

The SSP II permits customers or aggregators to participate in either or both CAISO wholesale day-ahead and/or real-time markets by bidding the resource's opportunity cost (energy price), quantity, and desired operating window under the current PDR construct, which only includes load shedding. The XSP asks customers to nominate hours in which they can shift their load to increase energy consumption during specific windows of high renewable generation, when the market could be at risk of (or actually) experiencing negative prices[37]. Since there is currently no wholesale market product for load increase DR, load increase bids and awards are always out of market. This may change for some resources as the CAISO is developing a load shift product for behind-the-meter battery resources. However, as described below, all bids and awards (load decrease and increase) were based on simulated market conditions and handled out of market.

8.2.2.2 MUA Demonstration Testing

Basic operating rules and assumptions were established to help simplify the process for testing MUA within the MVP framework:

1. **Order of commitments must be kept:** This was used as a proxy for priority when dispatches are made within the same operating window. For example, if a wholesale award was given before a distribution award, the distribution award could not override the original wholesale commitment unless it was additive in the same direction. Multiple scenarios were tested in this use case to better understand if one system would need to take priority to maintain reliability
2. **Use of the day-ahead wholesale market only**: While wholesale markets are not fully settled until the real-time market is run and awarded, to simplify the testing, assets were only allowed to bid into the simulated day-ahead markets. This avoided the complexity and practical barriers of participating in, and coordinating with, CAISO real-time markets for the MUA demonstration.

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product. Additional context and rationale on this position can be found at http://www3.sce.com/sscc/law/dis/dbattach5e.nsf/0/0EF9A015334951F8882582E4007ACC53/$FILE/R1503011-SCE%20MUA%20Working%20Group%20Report.pdf.

[36] Both the SSP II and XSP are run by PG&E's Demand Response team and approved through D.16-06-029 and D.17-12-003. The SSP II enables customers to monetize BTM resources in the CAISO wholesale market via the existing PDR product.

[37] Details about the SSP II and XSP are available at http://olivineinc.com/services/our-work/ssp/ and http://olivineinc.com/services/our-work/xsp/, respectively.

3. **Locational Marginal Pricing (LMP) used as a proxy for value of wholesale energy:** In all cases of energy only testing, the study used day ahead forecast LMPs as proxy for the wholesale price to be paid for energy; this is consistent with how energy imbalances are settled in the CAISO markets for PDR or NGR resources.
4. **Market risk was managed carefully:** To prevent exposure to non-performance or other challenges that could arise from the demonstration, markets were simulated for SSP II participating assets. The YB BESS continued to settle all imbalances in the CAISO market as a market resource subject to tariff, but costs were closely monitored and minimized while meeting test objectives.

The MUA process was not as automated as the core DERMS distribution service dispatch because of the MVP framework. Coordination between the wholesale market and DERMS was done manually for this demonstration. Constraints for the purposes of the DERMS MVP were determined manually by the DERMS Operator.

The demonstration tested progressively more difficult to coordinate scenarios to determine challenges, needs, and priorities of DERs providing distribution services in coordination with wholesale market participation. In addition, there was an exploration around a DERMS' potential impacts to settlement and the demand response baseline.

8.3 Challenges

8.3.1 Valuation of Distribution Services Undefined

The DERMS Demo did not attempt to determine the underlying value of distribution services, nor did it specify how distribution services should be enabled. While certain costs were used from the wholesale market, violation costs were generally made exceedingly high to prioritize distribution needs over other costs. Therefore, violation costs did not reflect real market costs.

Recommendations:
There needs to be continued involvement by all parties in the policy and regulatory worlds that are shaping the valuation discussion, including the DRP and IDER Proceedings.

8.3.2 Market Mechanisms

The investments needed to create and support a dynamic market for distribution services on a system as large and dispersed as PG&E's will be significant. The DERMS Demo implemented a day-ahead ask-bid-commit process as well as an hourly ad-hoc simulated market since there were minimal existing policy or regulatory standards in the area from which to draw. These were used more as mechanisms for the demonstration rather PG&E purporting this as the preferred method for dispatch.

Recommendations:
Without the widespread need for DER distribution services at this time, **targeted solutions could provide an opportunity to fill existing gaps in the absence of clear regulations or policy**, and prevent unjustified spending on a system-wide DERMS when there may not be a system-wide need. **Targeted customer programs or competitively sourced bilateral market contracts in the near-term may provide a method to overcome ambiguity in the distribution market space to more readily enable DERs to provide distributions services where needed.** This is currently how candidate distribution investment deferral projects are being approached.

8.3.3 Scheduled vs Actual Dispatches

To provide the most economic value for DER owners, even if certain dispatches are scheduled in the day-ahead market, the actual dispatch may deviate from the schedule based on real-time prices to generate more revenue. Because DERMS uses the given day-ahead schedules from aggregators to determine forecasted needs, significant deviations in real-time from this schedule could potentially invalidate any DERMS requests based on the original scheduled dispatch.

Recommendations:
More exploration is required to determine methods to best handle these types of situations. The use of constraints and worst-case forecasting are two possible tools to mitigate these types of issues.

8.3.4 BTM Customer Coordination

The demonstration was designed to control certain variables and best understand the topic of multiple uses between wholesale and distribution services. However, the end use customer is another important player who can have local optimizations including demand-charge management. As this was a live field demonstration, the team also had to manage the risk of negative bill impact as well as coordinating with local demand-charge management schemes. These limitations and the impacts on the conclusions are described below.

8.3.4.1 Impacts of Peak-Shaving Algorithm

The vendor's peak shaving algorithm is the main DER value driver for the commercial energy storage customers in the DERMS Demo. It tracks the monthly energy consumption data and uses the battery to shift load to reduce the customers' peak demand charges. Although the vendor was paid to allow PG&E to control the battery during the demonstration, the vendor did not change some of the normal operating properties of the battery, including the peak shaving algorithm. To simplify the testing, PG&E had originally requested the local control algorithm to be disabled during testing. However, this could not be fully accomplished and as a result, extra coordination was needed during testing and analysis of the results to account for the customer level optimizations.

Recommendations:
MUA requires transparency and coordination across customer-level, distribution, and wholesale programs. The effects of one program will have impacts on the others and must be taken into account to avoid issues with priority, settlement, and accuracy.

8.3.4.2 Default Charge Setting

The vendor's default operation for state of charge management on batteries for demand charge management is to start charging as soon as the battery is not full whenever it is not in active use. Therefore, the batteries would not sit idle unless they were actively programmed to zero by the team or already charged. This meant that an additional layer of coordination was needed between the individual battery and the DERMS and may not be reflective of the way a market participating asset might behave.

Recommendations:
SoC management for energy storage can become complicated if multiple programs are simultaneously attempting to manage assets. Clear priorities, rules, and coordination are imperative to avoid conflict.

8.3.4.3 Premise-Level vs Device Level Metering

The DR program performance was measured based on the entire premise level metering to make settlement calculations. However, the premise level data did not reflect the changes in load that were expected based on the DERMS dispatches. Ultimately, the DERMS Demo had to obtain and rely on device level metering to ensure the customer responded properly to DERMS commands.

Recommendations:
Different programs may require different types of metering depending on their structure, goals, and methods for verification. To ensure proper settlement, coordination among programs is necessary to ensure that each is monitored and measured appropriately.

8.3.4.4 Manual Coordination

Coordination was ad-hoc and manual given the small scale of deployment. Although a set of rules and processes were established, they evolved over the course of the demonstration as previously unforeseen issues arose. For example, because the bids had to be provided to the Scheduling Coordinator and they were in a simulated rather than actual market, they were implemented manually. This required a person be available to run the manual test during a specific window of time, failing which, the test could not be run.

In addition, there was an example of a manual dispatch that didn't follow the automated flexibilities provided to the DERMS system via the Aggregator Interface due to DERMS Operator error. This manual integration resulted in an error dispatching more than the provided flexibility, causing extra demand charges for the customer.

Recommendations:
It is expected that future markets and production systems will be highly automated, and should relieve many of the pain points from the manual implementation during the DERMS Demo.

8.3.4.1 Manual Constraints

There was no automated constraints engine as part of the DERMS Demo MVP. This meant the DERMS Operator had to manually determine any dynamic constraints and send them to participating assets.

Recommendations:
The ability to create, communicate, and verify adherence to constraints for DER customers is an active area of research for PG&E in upcoming DR and EPIC demonstrations. Limited constraints may be an effective method to cost-competitively increase hosting capacity while providing flexibility for DERs, given that these constraints are efficiently dispatched and strictly adhered to.

8.4 Results and Observations

8.4.1 Least-Cost Dispatch

The least-cost optimization successfully incorporated the pricing of violations, asset flexibility, and constraints to dispatch assets economically as shown earlier such as in Figure 28. The success of the least-cost dispatch was a prerequisite for testing all the scenarios. The optimization was successful as the costs for DER dispatches and violations were varied under different scenarios. In the absence of distribution violations, the optimization was able to dispatch assets based on energy arbitrage as shown in Figure 34.

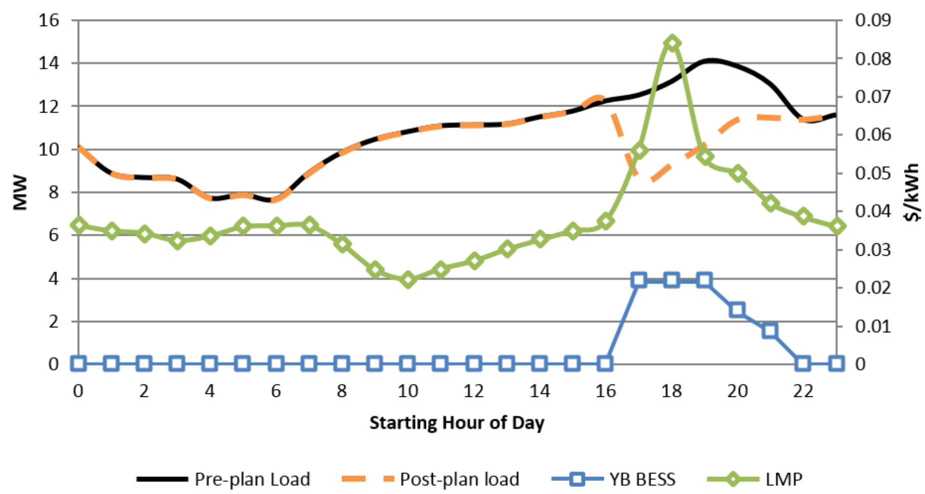

Figure 34: Energy Arbitrage Dispatch of YB BESS

8.4.2 MUA

8.4.2.1 Wholesale Price and Feeder Load Correlation

The demonstration was designed with a hypothesis that in *most* cases, the energy/capacity needs of the distribution grid are aligned with those of the transmission system. In other words, when the transmission system is peaking, most individual feeders around the service territory are also at or approaching their peak load. Assuming that DERs respond to these wholesale energy prices (LMPs), there may not be a need for separate distribution services for feeders aligned with wholesale energy pricing as shown in Figure 35.

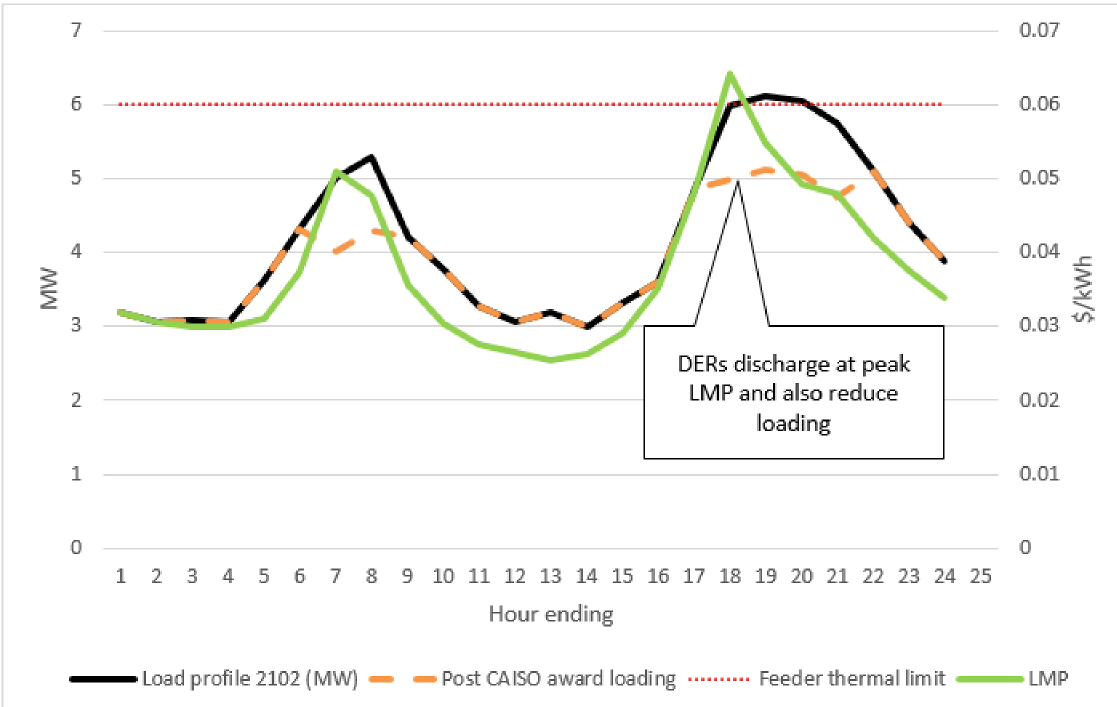

Figure 35: Effect of CAISO Wholesale Energy Awards on Demonstration Feeder with Simulated Feeder Limit

To support this hypothesis, an analysis compared the hourly wholesale energy prices at feeders in PG&E territory with feeder loading characteristics (Section 21 - Appendix). It found that less than 5% of the studied data points had a relatively significant inverse relationship. However, negative correlation does not necessarily mean there will be a problem on that feeder, as those negative correlations would need to line up temporally when and if a feeder is close to exceeding its capacity. As shown in Figure 36, this particular feeder has enough capacity (12MW) to absorb potential issues.

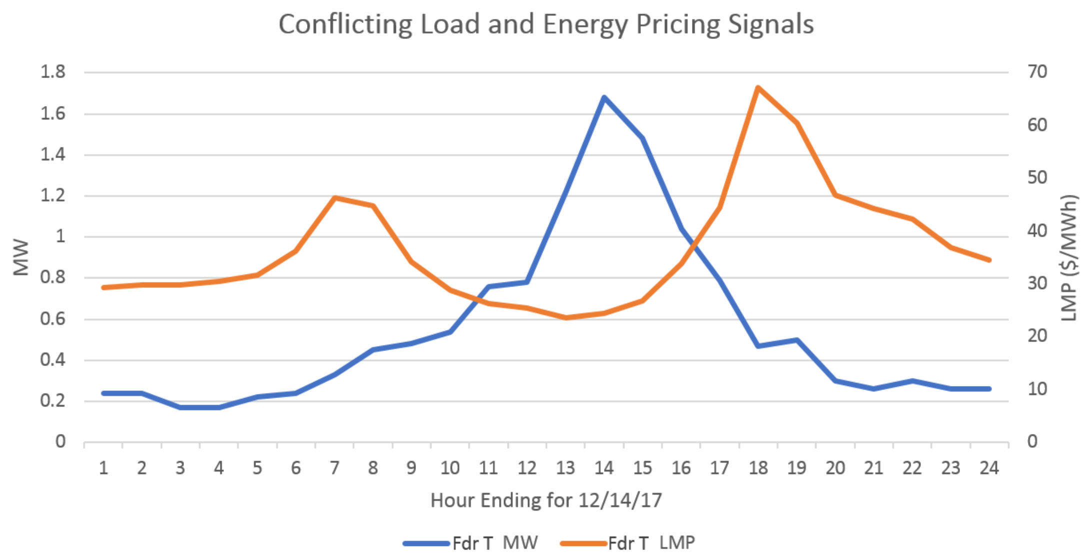

Figure 36: Conflicting Load and Energy Pricing Signals that Should Not Create Any Issues

However, if a negative correlation corresponds to times when that feeder is at or near capacity (forward or reverse) or voltage limitations, then it could potentially cause a compliance or safety issue if enough assets acted on that market signal. Figure 37 shows an actual feeder that is already near capacity limits in the morning when energy prices are low. If loads responded to these low prices, it could potentially create an overload condition. While these situations are rare today, as grid complexity grows, and system headroom is reduced for efficiency and affordability, it is expected that this issue will grow rather than decrease in the future.

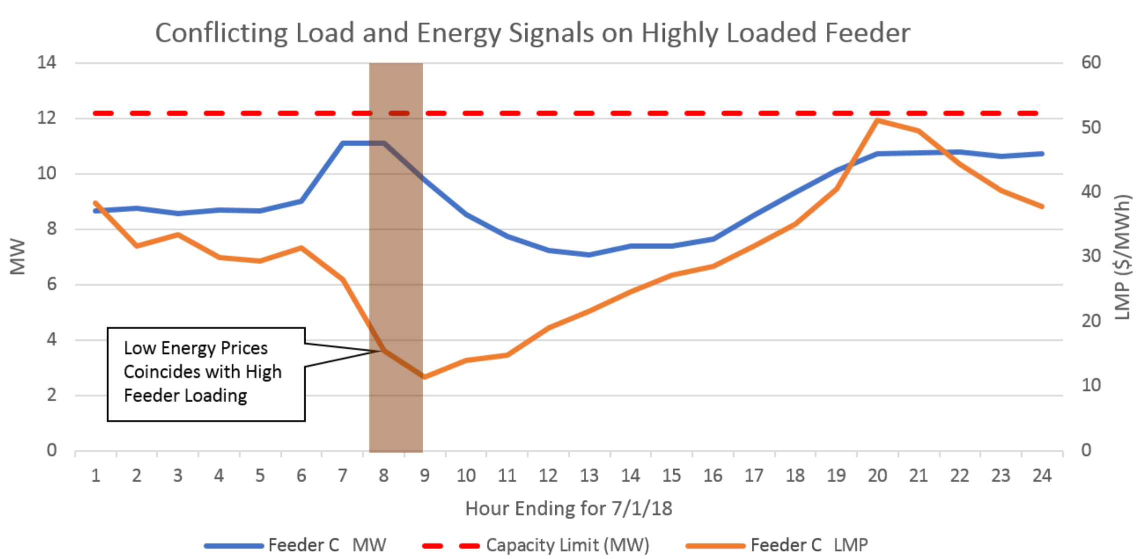

Figure 37: Conflicting Load and Energy Pricing Signals that Have the Potential to Create Issues

In addition, there are other wholesale markets besides energy that may not align with feeder loading including frequency regulation, or even customer end-use applications like demand-charge management. The demonstration tested the dual use of the YB BESS to offer frequency regulation in the wholesale market while applying a simulated constraint of 6 MW on the feeder. Because the frequency regulation market does not necessarily align with the LMP or general load shape and because of the wide swings in either direction around the net load when an asset is providing frequency regulation, the likelihood of exceeding a constraint can be even greater with assets participating in the frequency regulation market, as illustrated in Figure 38.

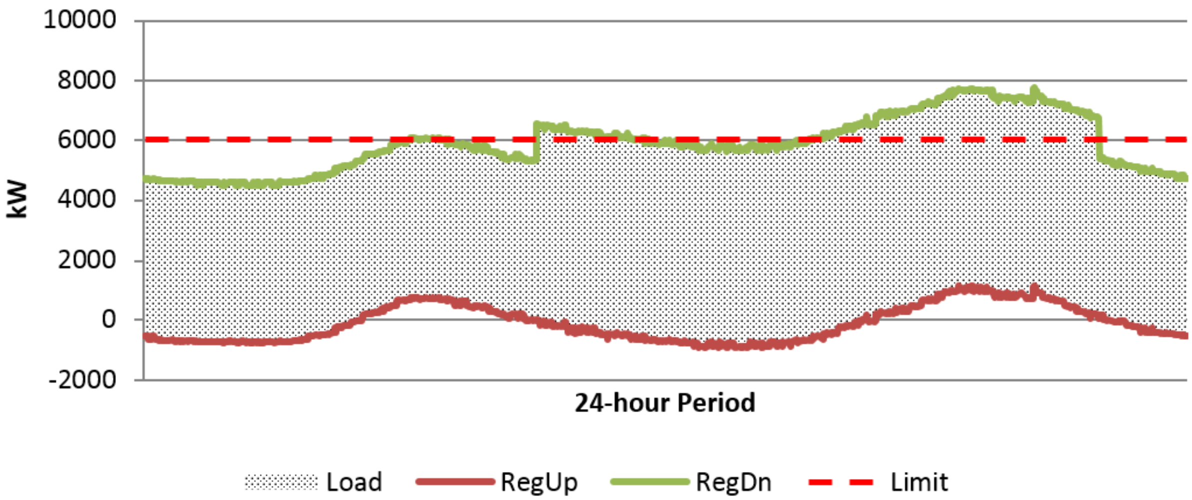

Figure 38: Frequency Regulation Awards with Simulated 6 MW Limit on Feeder

8.4.2.1 Priorities and Dispatch Needs

Table 11 shows the progression of tested scenarios from wholesale only signals to distribution priority, highlighting the need for distribution priority to overcome potential edge cases for distribution needs. Different constraint scenarios were tested with different products and different asset types and market rules (PDR for BTM and NGR for FTM). Conditions were simulated to test when distribution needs do not align with wholesale energy prices. For example, the LMP was time-shifted on the demonstration feeders to be highest around midday instead of in the evenings to simulate the potential negative correlation of wholesale price to load of say a noon-peaking type feeder. Section 0 - Appendix provides the background for each progressive scenario concluding that **to preserve distribution safety and reliability, distribution dispatch must have priority over wholesale market operations and visibility across both systems.**

Table 11: Progressive Scenarios Tested to Demonstrate Successes and Gaps of Different Prioritization and Control Schemes

#	Scenario & Market Construct	Demonstrated Successes	Demonstrated Gaps
1	CAISO Energy Pricing Aligns with Distribution Needs: **Wholesale Only**	Wholesale energy markets can provide distribution support when pricing aligns with feeder load profiles.	Relying solely on the wholesale market to provide distribution services is insufficient when feeder loading does not align with wholesale energy prices, or when DER assets are participating in non-energy markets (e.g. frequency regulation).
2	CAISO Dispatch Conflicts with Distribution Needs: **Wholesale Priority**	For certain cases, having wholesale priority over distribution dispatches can be successful.	If DERs in the wholesale market do not have enough residual capacity for a distribution market, then distribution needs will be unmet.
3	CAISO Dispatch Conflicts with Distribution Needs: **Distribution Priority**	For certain cases, having distribution priority over wholesale dispatches can successfully overcome issues found in Test 2.	Even with distribution priority for dispatches, constraints are still needed to avoid potential issues on distribution.
4	CAISO Dispatch Conflicts with Distribution Needs: **Constraints + Wholesale Priority**	For certain cases, having distribution constraints and then wholesale priority for active dispatch can successfully overcome issues found in Test 3.	Even with distribution constraints, there are issues that may remain if wholesale is prioritized for active management dispatch.
5	CAISO Dispatch Conflicts with Distribution Needs: **Constraints + Distribution Priority**	Prioritizing distribution constraints and active dispatches over wholesale can overcome all the potential edge cases shown in the previous tests.	**None when sufficient locational DER volume, availability, and dispatch assurance.**

8.4.2.2 DR Settlement Baseline Influence

An analysis to evaluate the potential effects of MUA on settlement was done using the same methodology that CAISO uses to settle Demand Response participation with the PDR product. The study (Section 0 - Appendix) used theoretical data to demonstrate multiple ways in which a DERMS dispatch could potentially influence the baseline used to calculate DR settlement. Lowering this baseline would make it more difficult for a customer to meet a load reduction DR award, while raising it would make it easier to meet a load reduction DR award.

Without proper transparency and coordination among programs, a customer being dispatched via a DERMS could be rewarded or penalized through this method of DR settlement. In addition, savvy customers may potentially be able to manipulate DR baselines with storage products to raise load during adjustment period times, and then take advantages of both DR and higher pricing to generate more revenue during the DR event window. While there are some protections built-in to prevent excessive deviations (±20% limit on "day-of" multiplier), further coordination and transparency would allow for a more equitable transaction. This could potentially include CAISO modifying how performance in the wholesale market is calculated to allow for exclusion of distribution events, similar to how it treats the impacts of wholesale awards on each other.

8.4.2.3 Conflicting or Additive Signals

Assets participating in multiple markets may encounter conflicting or aligned signals from distribution and wholesale markets. Without coordination and transparency among programs, including local customer systems like peak-shaving algorithms, customers may be penalized or overly compensated for their dispatches. In addition, rules need to be put in place for expected customer behavior, as well as potentially re-evaluating current penalty mechanisms to ensure penalties justly reflect the potential impacts on the system. PG&E and other stakeholders are continuing to work through these challenges in forums like the CPUC's Energy Storage MUA Working Group.

Additive Signals

Figure 39 provides an example of potential customer outputs when both distribution and wholesale energy signal a dispatch in the same direction.

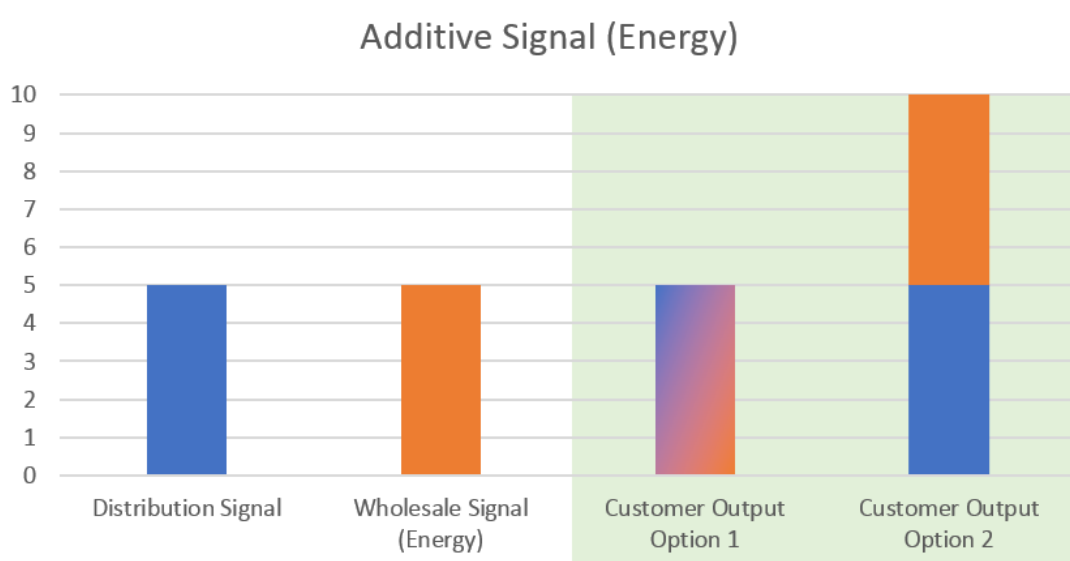

Figure 39: Additive Signals from Distribution and Wholesale (Energy)

Rules will need to be established to determine how customers and 3rd party DER aggregators should bid and then be evaluated to determine whether Option 1 in Figure 39 will be in compliance with both the distribution and wholesale signals, or if the customer must dispatch as shown in Option 2. There may be issues around compensation in Option 1, while Option 2 would want to avoid unintended consequences of over dispatching based on the request.

Conflicting Signals

Figure 40 provides an example of potential customer outputs when distribution and wholesale energy signal a dispatch in opposite directions.

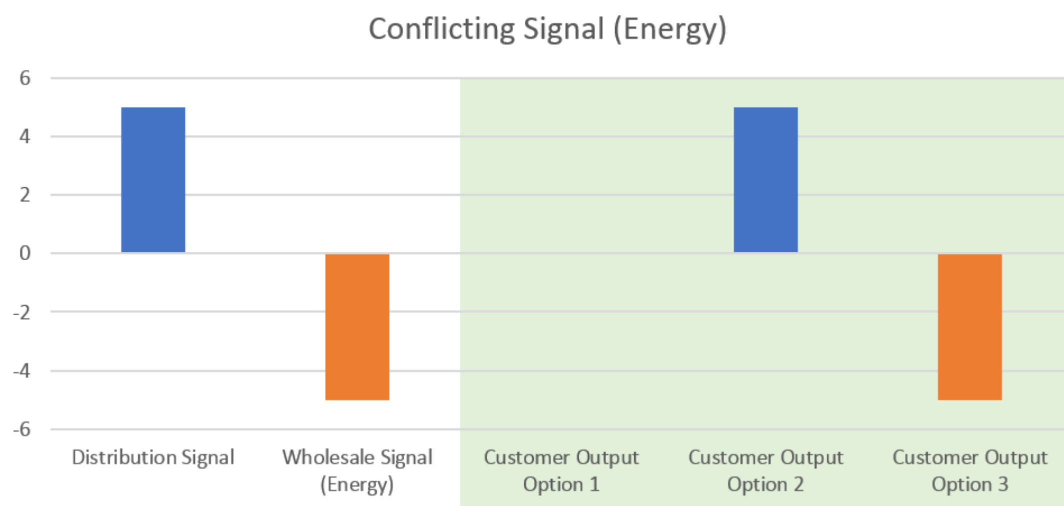

Figure 40: Conflicting Signal from Distribution and Wholesale (Energy)

Without established rules, it is unclear how customers should respond if given conflicting signals. Option 1 in Figure 40 could potentially be in compliance or out of compliance with both the distribution and wholesale signals, by effectively doing nothing. Options 2 and 3 are complying to one signal and not the other, however there is no structure to either implement penalties, or potentially remove penalties if say a particular dispatch has priority.

Figure 41 shows a similar example using a wholesale frequency regulation signal instead of an energy signal. In the graph, the shaded regulation signals indicate that there is the *potential* to be called up to that amount for a short duration of time. This can become more complex based on the variability of the regulation signals, where during certain times it may be in compliance with both, and at other times it is not.

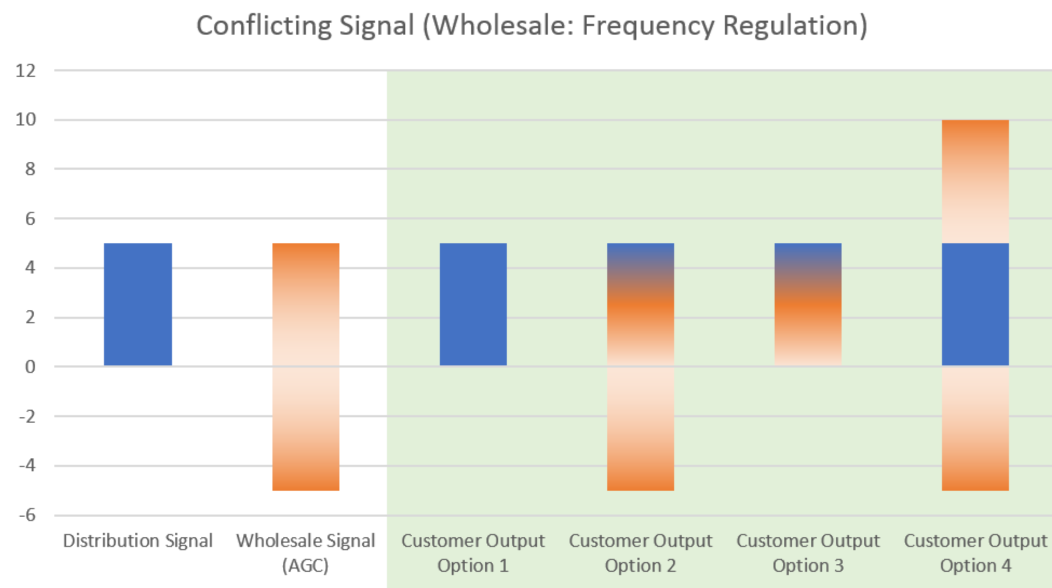

Figure 41: Conflicting Signal from Distribution and Wholesale (Frequency Regulation)

Penalties

Distribution priority over wholesale signals was discussed earlier, with the caveat of potential emergency distribution ratings under severe transmission system issues. If penalties are assessed for noncompliance, transparency and coordination of markets is foundational to ensuring these are equitable. Penalty structures may need to be re-evaluated to consider the additional challenges faced by distribution in terms of both a radial system, and the reduced scale and diversity of available assets. Meaning, a particular customer's non-conformance to a distribution signal may have a larger relative impact on the distribution system than non-conformance in the wholesale market. This may impact both the scale of penalties as well as the criteria for severe penalties like decertification.

The CPUC's Energy Storage MUA Working Group is in the process of evaluating these issues including additional rules and guidelines for enforcement, technical configuration (e.g., metering configuration to support multiple grid services delivery), primacy, transparency, and coordination. While technically feasible to implement, there will have to be a consideration of the overall benefits and costs for implementing MUA and the actual value to customers in the long run particularly if MUA principles and rules are expanded to all other in-front-of-the-meter and behind-the-meter DERs.

9 DERMS Next Steps

Because of the nascent state of the industry during the DERMS Demo, a primary goal of the project was to clarify DERMS requirements and characterize barriers to deployment at scale. The project took the opportunity to put a stake in the ground of a potential future and used those learnings to highlight the challenges of the proposed methods, barriers to scale, and also the steps that can be taken in the near-term to prepare for a grid with high DER penetration.

As shown in the preceding sections, there are significant challenges to building out a distribution market at scale at this time. Creating open markets for generators to participate in the transmission system was a long and complex process. Distribution systems, with more circuit and device diversity, and hundreds of thousands of independent generators already connected, are even more complex to model than transmission systems.

Additionally, the systems needed to support a dynamic market for distribution services on PG&E's large and dispersed distribution system will be significant. The enablement of DERs must be balanced with the reliability needs and operational parameters. If California moves toward a dynamic market for distribution services, PG&E is committed to working with 3rd parties and the CPUC to find cost effective and viable solutions to enable this transformation. PG&E's distribution grid can become an interoperable platform that will communicate and share the necessary information to maintain grid reliability and cybersecurity but allow transactions to create a sustainable energy future. The structure of this market has not yet been defined, so the exact technology requirements for market mechanisms are still largely unknown.

However, **PG&E believes certain foundational technology is required regardless of future market decisions.** These building blocks of situational awareness and grid analytics provide distribution Operators the tools they need to handle increasing grid complexity today, while providing the engine to enable distribution services in the future. PG&E is pursuing these technology investments through the Integrated Grid Platform as part of the 2020 and 2023 General Rate Case, specifically via a DER-aware ADMS.

9.1 DER-Aware ADMS

Without a clear industry definition of DERMS at the start of the project, PG&E took a "DERMS is everything" approach in order to solve the specific project use cases. However, through the implementation of the DERMS, it became evident that there were distinct areas of responsibility that fell into a utility ADMS application and a distinct DERMS application. The ADMS and the DERMS need to be tightly integrated and may even be provided by the same vendor.

The ADMS is the system of record for the real-time topology of the as-operated grid and has all the data to properly model the electrical characteristics of the system. A "DER-Aware" ADMS means that DERs are properly modeled in the system and considered in the calculations, applications, and situational awareness (e.g. masked load) of the ADMS. However, this does not necessarily mean that an ADMS will control or dispatch DERs. Regardless of having a DERMS, this type of information is necessary for operating the grid under high DER penetration.

The DER-aware ADMS provides the foundational information for any future DERMS. **The DER-aware ADMS is best suited to provide any information tied the electrical characteristics of the grid.** This means that it should be the source for:

- Real-time and Forecasted Situational Awareness
- Defining Grid Needs
- Creating Electric Based DER Aggregations
- Calculating Sensitivities of DERs to Impact Specific Grid Locations

For a separate DERMS to be able to provide these types of functionalities, it would create unnecessary overhead by duplicating the modeling and integrations of the existing ADMS. Furthermore, while regulations and policies of distributed DERMS are being developed, in the near-term the ADMS will integrate via SCADA with larger DERs through simple logic, decentralized DERMS, and microgrids.

9.2 DERMS vs ADMS

As previously discussed, PG&E discovered through this demonstration that it would not be prudent to build out a full-blown DERMS today based on the ambiguity of the market. However, the DERMS Demo revealed clear boundaries for PG&E between ADMS and DERMS helping define near-term ADMS requirements and future DERMS needs.

PG&E considers ADMS as managing the electrical characteristics, while a DERMS will ingest this information and incorporate non-electrical considerations such as pertinent program rules and cost to optimize dispatch of DER assets. Additionally, the ADMS does not need to directly communicate with all DERs, so the DERMS will be the platform that reaches out to the majority of DERs either through aggregators or direct connections. Figure 42 shows a breakdown of how PG&E currently views ADMS versus DERMS capabilities, allowing for increased capabilities and flexibility to address an evolving industry.

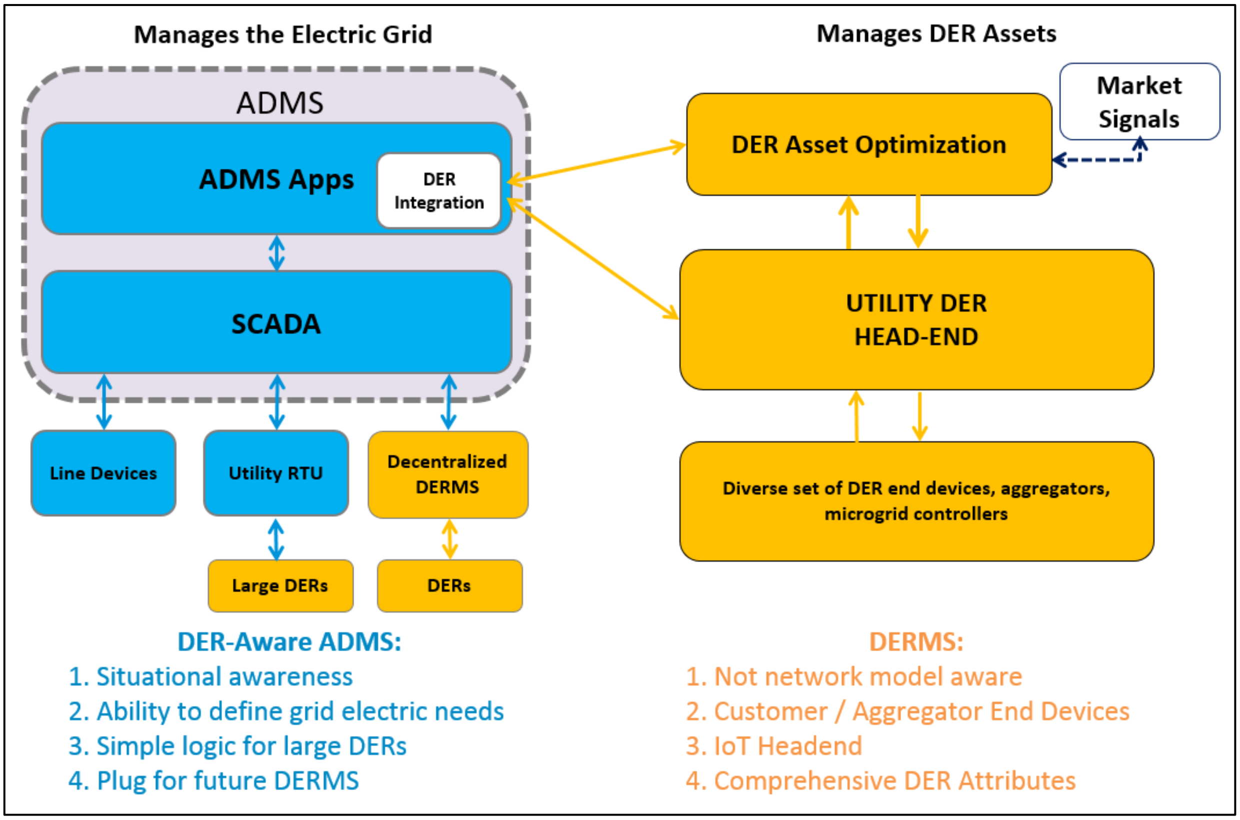

Figure 42: ADMS vs DERMS Capabilities

Figure 43 goes a step further, giving representative types of use cases that may be pursued by a utility and some of the required functionality to enable those use cases. The more immediate use cases are around being DER-aware through ADMS functionality with some limited control for large SCADA connected DERs, which should happen regardless of future market interactions of DERs. The more future based use cases address increasingly interactive DER exchanges with both large and small DERs. The required functionality shown for the use cases often builds on the technical functionality of preceding use cases in the time line. While this shows a technical progression, it does not show the correlating policy and regulatory frameworks required to enable future DERMS functionalities.

Figure 43 is meant for illustrative purposes, and is neither exhaustive nor a fixed roadmap for DER functionality at PG&E. However, PG&E is planning to implement items in the DER-Aware area via the IGP and ADMS projects proposed in the 2020 and 2023 GRC filing.

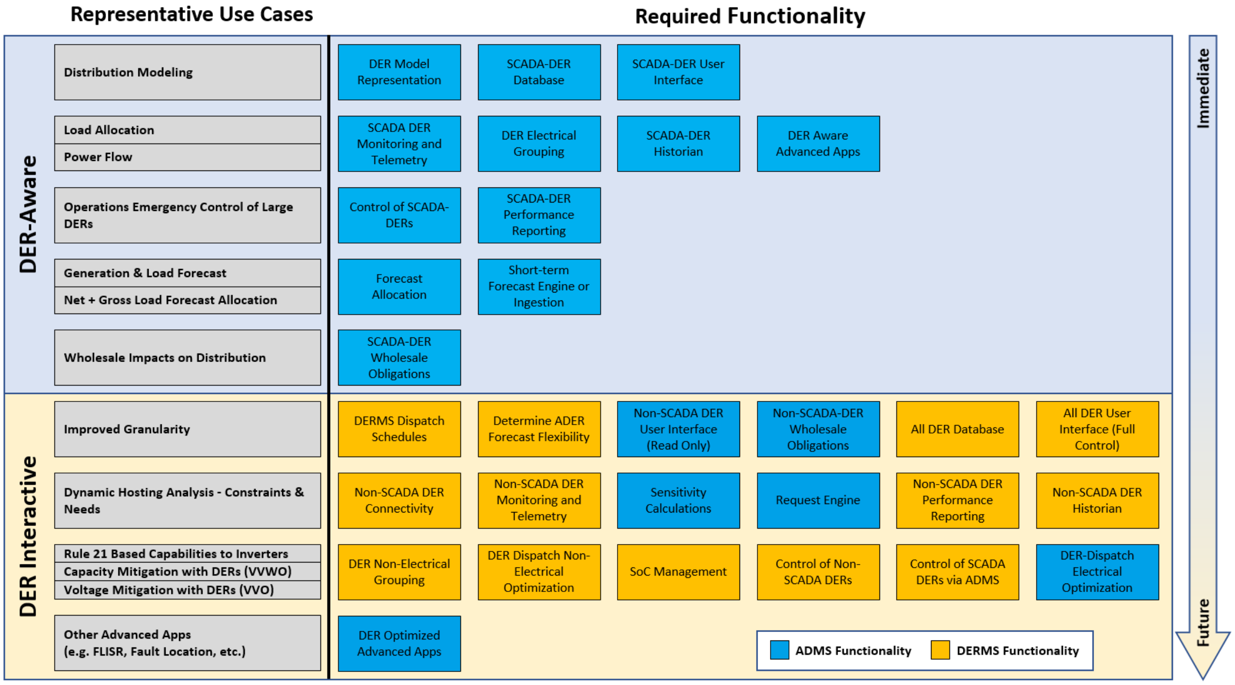

Figure 43: Illustrative DER Related Use Cases, Required ADMS or DERMS Functionality, and High-Level Time Frame

9.3 Planned Future DERMS Work

As previously discussed, PG&E is planning to productionalize a DER-Aware ADMS via the IGP projects proposed in the 2020 and 2023 GRC filing. While PG&E tested a broad market-based approach in the DERMS Demo, there are additional use cases for DERMS in areas like management of DERs for distribution investment deferral, enabling safe and reliable operations of market participating DERs under abnormal grid conditions, and avoiding capacity upgrades by automating operational constraints for DER customers. PG&E is focusing on methods for enabling DERs to realize value under constrained conditions either from the interconnection process, abnormal grid conditions, or resiliency scenarios, while providing the dispatch assurances required by the utility. These projects will be more near-term focused through the EPIC 3 portfolio and other avenues.

To use 3rd party DERs to provide distribution grid support functions, it is critical that structures, rules, contracts, and failsafes are created to ensure that the safety, reliability, and compliance of the grid are not compromised by reliance on 3rd party systems. Solutions for these challenges will also be explored by PG&E through EPIC 3, demand response pilots, candidate distribution investment deferral projects, and other research efforts.

10 Value proposition

The purpose of EPIC funding is to support investments in technology demonstration and deployment projects that benefit the electricity customers of PG&E, San Diego Gas and Electric (SDG&E), and Southern California Edison (SCE). EPIC Project 2.02 DERMS has demonstrated the use of DERMS technology to coordinate both 3rd party aggregator-operated and utility-operated DERs to manage capacity constraints and mitigate voltage issues. Such capabilities qualify DERMS technology as one of the solutions to manage the emerging issues resulting from high DER penetration, to respond to the changing net load profile in California, to coordinate DERs to support grid needs, and to potentially facilitate the continued growth and integration of DERs. However, the project also showed that a number of improvements are required at PG&E to fully leverage DERMS technology at scale.

10.1 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:

- *Reliability*: While significant problems experienced by PG&E because of DERs are relatively infrequent today (e.g. masked load, capacity and voltage violations, reverse power flow), DER penetration is expected to increase in the future and DERMS technology could address the associated increase in issues related to the planning and operation of an increasingly complex distribution grid.

- *Affordability*: DERMS technology may allow PG&E to avoid costly upgrades and plan the grid more efficiently. DERMS technology may also enable DERs to be more effectively used for wholesale market participation, unlocking additional value streams for customers and optimizations for front of the meter resources.

- *Safety:* Better visibility into DERs on the grid will give the utility more confidence that any switching operation on circuits with DERs accounts properly for the contributions of DERs, better preserving safety in situations where the grid is abnormally switched.

10.2 Secondary Principles

EPIC also has a set of complementary secondary principles. This EPIC project contributes to the following four secondary principles: societal benefits, greenhouse gas (GHG) emissions reduction, low-emission vehicles/transmission, and economic development.

- *Societal benefits*: By potentially enabling higher DER penetration without costly grid upgrades, this project supports California's clean energy policy goals and advances PG&E's mission to "reliably deliver affordable and clean energy to our customers...while building the energy network of tomorrow."

- *Greenhouse gas (GHG) emissions reduction*: Flexible resources can enable reliable operation of the grid with fewer fossil fuel-fired generating 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. This project helped PG&E better understand how these flexible resources could be used in future programs, via coordination of DERs with a DER Management System. Perhaps more importantly, this project showed PG&E what types of considerations the utility should make for program development.
- *Low-Emission Vehicles/Transportation:* Electric vehicles and their infrastructure may be a potential significant source of DERs in the future. Distribution grid operators will need the same types of situational awareness and management capabilities demonstrated in the DERMS demo to manage electric vehicle growth to avoid compromising grid stability. A DERMS platform may serve as a critical component in ensuring electric vehicles are good citizens of the grid as well as providing an opportunity to add value through distribution grid services.
- *Economic development:* California has dedicated substantial funding towards procuring BTM storage (Self Generation Incentive Program) and policy effort in developing the PDR model used for Demand Response. The DERMS Demo showed how DERs that were initially procured for BTM value, may also be able to provide value to the grid. This value has the potential to be taken even further by using assets as resources in Demand Response programs, thereby creating an additional revenue stream for customers who choose to participate.

10.3 Key Accomplishments

The following summarizes the key accomplishments of the DERMS Demo:

- **Successfully field demonstrated new DERMS technology** to mitigate real-time and forecasted voltage and capacity constraints using active and reactive power of 3rd party aggregated and utility DERs.
- **Progressed the state of the industry** by successfully defining, building, and demonstrating new DERMS capabilities while identifying challenges in the field through collaboration with participating vendors and industry leaders.
- **Demonstrated the capabilities of a least-cost dispatch** to efficiently dispatch DERs to enable distribution services or provide energy arbitrage.
- **Provided enhanced situational awareness (via ADMS) and DER distribution services (via DERMS)** under normal and abnormal switching conditions while incorporating wholesale participation into distribution forecasts and optimizations.

- **Evaluated a subset of MUA use cases** through coordination with customer sited demand charge management, distribution services, and CAISO wholesale markets.

- **Exchanged distribution grid services with aggregated 3rd party resources** through an IEEE 2030.5 interface with custom extensions.

- **Defined near-term and long-term ADMS and DERMS needs while establishing a cost-effective DER strategy**. Implementing the DER-Aware ADMS and DERMS strategy through PG&E's IGP Program, the 2020 and 2023 GRC filing, and upcoming research projects.

10.4 Key Recommendations

For industry stakeholders considering or involved with DERMS technology, PG&E provides a variety of recommendations:

10.4.1 Technology Recommendations and Next Steps

Invest in foundational technology: Investments in improved data quality, modeling, forecasting, communications, and a DER-aware ADMS are required to achieve any efficient dispatch of DERs in the future. Regardless of future policy or market trends, Distribution Operations will need these tools to safely and reliably operate the grid as complexity increases with the continued growth of DERs.

- **PG&E Next Steps:** The learnings and requirements gathered through the DERMS Demo directly influenced the development of PG&E's IGP strategy and requirements for implementation of a DER-aware ADMS for the 2020 and 2023 GRC filing, and proposed projects for EPIC 3.

Distribution services provided by DERs must be coordinated with existing utility mechanisms for capacity and voltage issue mitigation: DERMS is a tool for managing the grid in concert with traditional utility grid management tools. In some instances, it may be more efficient and cost competitive to use traditional grid infrastructure investments, manual/automated settings changes, circuit reconfigurations, or existing field devices to maintain grid safety, reliability, and compliance. Therefore, DERMS must be able to coordinate with these other systems in real-time to ensure cost-effectiveness as well as making sure they work together and do not oppose or undermine one another.

- **PG&E Next Steps:** The learnings from the DERMS Demo will be used to implement DER-related Operational procedures, processes, and integrations through the DER-aware ADMS implementation and candidate distribution investment deferral projects.

An ADMS should be the source of power system situational awareness, and provide power system calculations, grouping, and other information to an integrated DERMS: Demonstrating an ADMS integrated with a DERMS clarified what types of functions naturally reside in each system. PG&E considers a DER-aware ADMS as managing power system related parameters and potentially larger connected DERs. A DERMS builds on that foundation by layering on and incorporating more non-electrical considerations to optimize dispatch of DER assets regardless of size. Non-electrical information allows a DERMS to enhance baseline electrical groupings or optimizations based on pertinent economic, customer, or program specific information. Additionally, the ADMS does not need to directly communicate with all DERs. DERMS is expected to be the platform that reaches out to the majority of DERs either through aggregators or direct connections.

While tight integration is required (DERMS could even be an offering from an ADMS vendor), separating these functions reduces the complexity of maintaining redundant models and databases. Additionally, the ADMS is used for the day to day operations of the grid, and having a separate DERMS reduces the burden on the ADMS and allows for greater flexibility to evolve as conditions become more defined. PG&E is pursuing this vision of a DER-Aware ADMS through the 2020 and 2023 GRC filing.

- **PG&E Next Steps:** This strategy and approach is integrated into PG&E's DER-aware ADMS requirements being proposed in the 2020 and 2023 GRC filing, and will be pursued in further DERMS demonstration projects.

10.4.2 Operational Recommendations and Next Steps

Develop methods to ensure DERs provide sufficient availability and dispatch assurances to offer grid services: Distribution Operators have historically been the owners, maintainers, and operators of the equipment and systems assuring grid safety, reliability and compliance. To use 3rd party DERs to provide distribution grid support functions, it is critical that structures, rules, contracts, and failsafes are created to ensure that the safety, reliability, and compliance of the grid are not compromised by reliance on 3rd party systems.

- **PG&E Next Steps:** Solutions for these challenges will be explored by PG&E through EPIC 3, demand response pilots, and implemented in the near-term through candidate distribution investment deferral projects.

Enable DERMS capabilities on an as-needed basis at constrained distribution locations: Optimization technologies, control systems, regulations, and standards for incorporating wholesale transmission and distribution pricing signals into DER operations may be expected to evolve significantly, and to decrease in costs for both software and hardware over the next decade. Without the widespread need for DER distribution services at this time, targeted solutions would provide an opportunity to fill existing gaps in the absence of clear regulations or policy and develop critical DERMS functionalities. Targeted deployment would also help prevent unjustified spending on a system-wide DERMS when there may not be a system-wide need.

- **PG&E Next Steps:** PG&E plans to implement targeted solutions through candidate distribution investment deferral projects while continuing exploration in policy forums and EPIC 3.

Bilateral market contracts and targeted customer programs may be the most efficient transaction mechanism for distribution services in the near-term: The investments needed to support a dynamic market for services on a system as large and dispersed as PG&E's distribution system will be significant. While this may be required in the long-term, to ensure affordability for customers, it would not be prudent to prematurely scale complex markets system-wide. Targeted customer programs and competitively sourced bilateral market contracts in the near-term may provide a method to overcome ambiguity in the distribution market space to more readily enable DERs to provide distributions services where needed.

- **PG&E Next Steps:** PG&E plans to implement near-term DERMS functionality like candidate distribution investment deferral projects through competitively sourced bilateral market contracts and is exploring the use of the same targeted customer programs as those leveraged in EPIC 2.22 – Demand Reduction through Targeted Data Analytics to further enable DER value.

Advance maturity of standards, policies, and regulations: PG&E and industry leaders should continue to be engaged in the various standards, policy, and regulatory bodies that are shaping the industry. EPIC and other research and development initiatives around the country have helped push the conversation forward, but more investment is needed to help grow this evolving industry.

- **PG&E Next Steps:** Continued involvement in forums like EPIC, IEEE, CPUC Proceedings, and the Energy Storage Proceeding's MUA Working Group are necessary to shape technology and drive alignment between regulators, utilities, vendors, and customers.

10.5 Technology Transfer Plan

10.5.1 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

- *IPC Grid; San Francisco, CA |March 30, 2016*
- *EPIC Symposium; Sacramento, CA | June 22, 2016*
- *IEEE PES Smart Grid Technology Conference; Minneapolis, MN | August 31, 2016*
- *Verge Conference; Santa Clara, CA | September 19, 2016*
- *EPRI Power Delivery and Utilization Advisory Meeting; September 19, 2016*
- *DistribuTECH; San Diego, CA | Jan 31, 2017*
- *IEEE Smart Grid Webinar Series (on DERMS); Online | March 9, 2017*
- *SEPA Utility Conference; Tucson, AZ | April 25, 2017*
- *GE Mind and Machines Conference; San Francisco, CA | November 25, 2017*
- *DistribuTECH; San Antonio, Texas | Jan 23-25, 2018*
- *Silicon Valley Energy & Sustainability Summit; Redwood City | May 24, 2018*
- *2018 IEEE Power and Energy Society General Meeting; Portland, Oregon | Aug 7, 2018*
- *CIGRE Grid of the Future Symposium; Reston, VA | October 28, 2018*

Information Sharing Through Papers and Working Groups

- *NREL Whitepaper: Coordinating Distributed Energy Resources to Increase Grid Flexibility: A Case Study of Pacific Gas & Electric*
- *EPRI Whitepaper: Understanding DERMS Whitepaper*
- *Joint CA IOU Whitepaper: Smart Inverters*
- *Joint CA IOU Whitepaper: DERMS*
- *EPRI DERMS Working Group*
- *EPRI P174 DER Integration Program*
- *IEEE p2030.11 DERMS Functional Specification Working Group*
- *T&D World Article: Innovation Unlocks Grid Benefits*
- *Gridworks - Transmission-Distribution Operations Interface Working Group*

Information Sharing Forums Planned

- *DistribuTECH; San Antonio, Texas | February 1, 2019*
- *EPRI Standards and Protocols Working Group*

This list does not include PG&E press releases, PG&E internal workshops and seminars or external industry publications that have reported on the demonstration. Additionally, a nationwide benchmarking effort with other utilities is currently underway to share findings and scope future work.

10.5.2 Adaptability to other Utilities and Industry

The key takeaways and recommendations provided by this demonstration are applicable to all utilities and industry partners considering DERMS technology. While states like California have specific drivers fueling DER growth, these trends and related challenges are expected to grow in the future.

10.6 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.

11 Metrics

The following metrics were identified for this project and included in PG&E's EPIC Annual Report as potential metrics to measure project benefits at full scale.[38] Given the proof of concept nature of this EPIC project, these metrics are forward looking.

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[38] 2015 PG&E EPIC Annual Report. Feb 29, 2016. http://www.pge.com/includes/docs/pdfs/about/environment/epic/EPICAnnualReportAttachmentA.pdf

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
3. Economic benefits	
f. Improvements in system operation efficiencies stemming from increased utility dispatchability of customer demand side management	See Section 8 (Economic Optimization)
7. Identification of barriers or issues resolved that prevented widespread deployment of technology or strategy	
b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360)	See Section 6 (Situational Awareness)
d. Deployment and integration of cost-effective distributed resources and generation, including renewable resources (PU Code § 8360)	See Section 7 (Distribution Services)
9. Adoption of EPIC technology, strategy, and research data/results by others	
c. EPIC project results referenced in regulatory proceedings and policy reports	See Section 9 (DERMS Next Steps)
d. Successful project outcomes ready for use in California IOU grid (Path to market)	See Section 9 (DERMS Next Steps)

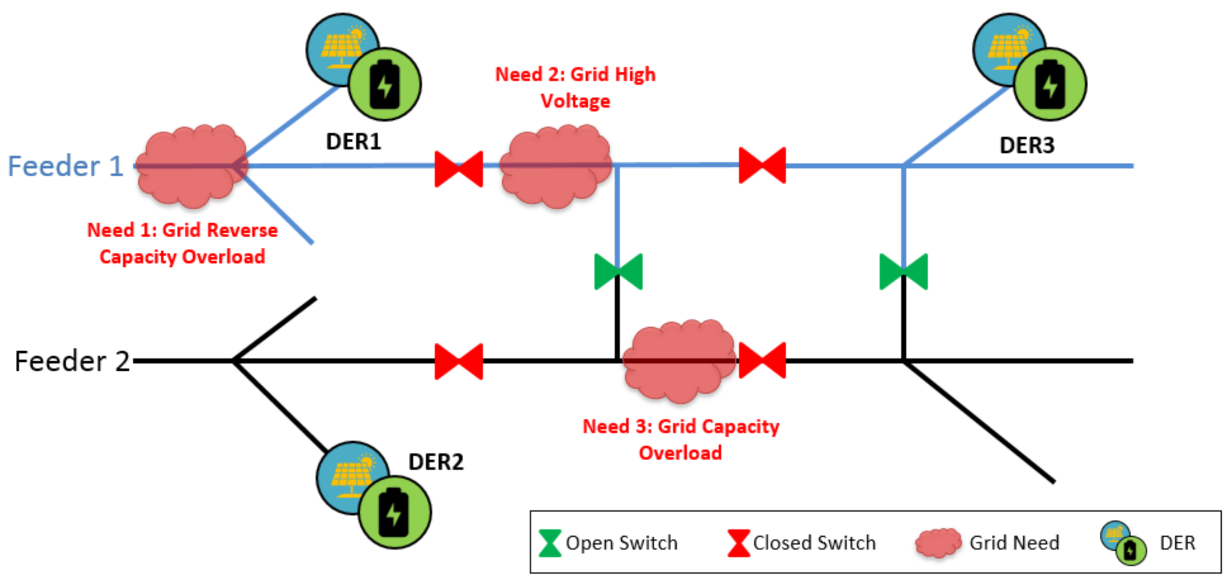
12 Conclusion

The DERMS Demo successfully demonstrated the potential of DERMS technology, while creating key learnings that helped further the industry and identify ADMS and DERMS needs for PG&E. The project successfully leveraged 3rd party aggregated and utility DERs to provide distribution services via an automated market structure while testing aspects of MUA. Through collaboration with the participating vendors, other PG&E demonstrations, and industry leaders, the DERMS Demo progressed the state of the industry. It also allowed PG&E to define near-term and long-term ADMS and DERMS needs while establishing a cost-competitive DER strategy.

Outstanding policy, regulatory, and program ambiguity make it imprudent to implement a full-scale DERMS immediately. However, results of this project provide clear next steps PG&E and the industry can take towards fulfilling near-term needs operating a more complex grid, while building foundational functionality that can be used to enable future grid services. Using the lessons learned through this demonstration, PG&E is pursuing these technology investments through the Integrated Grid Platform Program as part of the 2020 and 2023 General Rate Case filing. PG&E is also proposing further DERMS exploration in EPIC 3 and other avenues, building upon the learnings of the DERMS Demo to develop and demonstrate more near-term DERMS related functionality.

13 Appendix A: Grid Need Specific Sensitivities of DERs

The DERMS demo used DER sensitivities related to a particular grid need to determine how to best dispatch ADERs to resolve a problem. There were three types of sensitivities used: Amps/kW, Volts/kW, Volts/kVAR. ADERs will have different sensitivities based on location, grid needs, and circuit characteristics which can change based on abnormal switching. This varied response emphasizes the need for dynamic aggregations. The following two examples illustrate how sensitivities differ for capacity and voltage based on circuit characteristics, location, and abnormal switching.

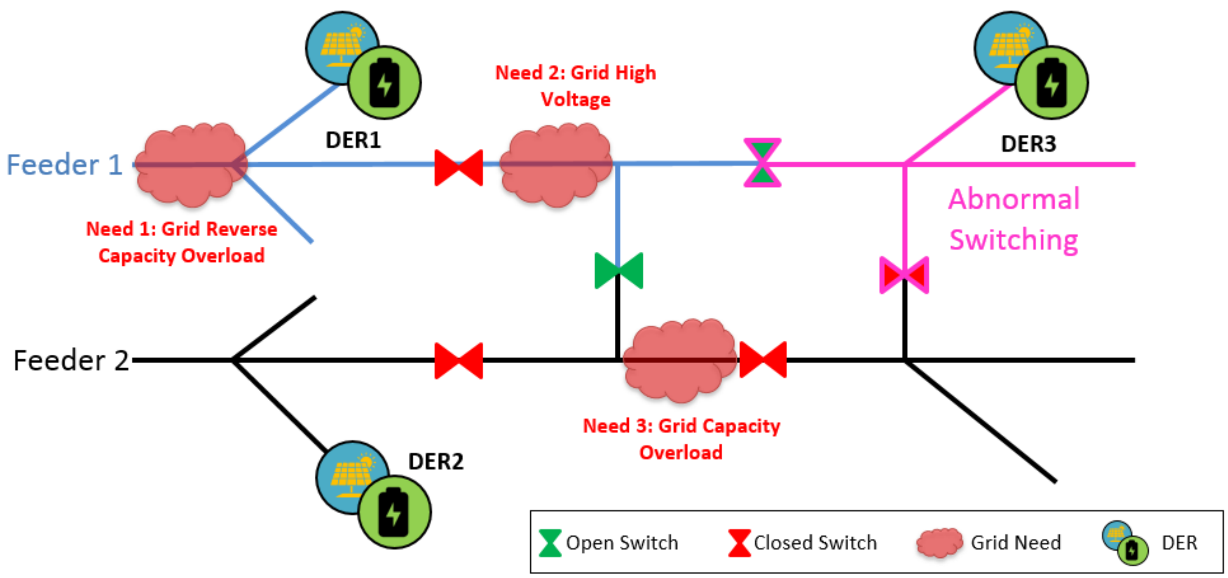


DER	Need 1 Support: Amp Sensitivity (A/kW)	Need 2 Support: Voltage Sensitivity		Need 3 Support: Amp Sensitivity (A/kW)
		V/kW	V/kVAR	
DER1	0.03	0.0006	0.0005	0
DER2	0	0	0	0
DER3	0.025	0.0005	0.0009	0

Figure 44: Example 1 of Grid Needs and DER Sensitivities in As-Built Topology

Figure 44 shows the sensitivities of each DER to different grid needs. For example, every kW that DER3 can dispatch (load/charge) will reduce the reverse capacity overload by 0.025A. The figure also shows the importance of topology for capacity constraints, where the capacity issue can only be mitigated if it is on the source-side of the DER. Accordingly, DER2 is unable to provide any support (0 A/kW) to resolve Need 3. Voltage support is not source-side topology dependent, and therefore both DER1 and DER2 can potentially mitigate Need 2. Circuit characteristics can also potentially affect the impact kW or kVAR can have when mitigating an issue. This suggests that ADERs formed to support voltage needs may be better grouped by voltage sensitivity, whereas those formed to support capacity needs can be done through topology or sensitivities.

The DERMS Demo used the given sensitivities in combination with pricing provided by aggregators to determine the most cost-effective dispatch within the constraints of the system and assets. For example, both DER1 and DER3 can support Need 1 to different degrees. If they were priced the same per kW, it would be more efficient to dispatch DER1 because each kW dispatched from DER1 has a greater impact on the grid need.



DER	Need 1 Support: Amp Sensitivity (A/kW)	Need 2 Support: Voltage Sensitivity		Need 3 Support: Amp Sensitivity (A/kW)
		V/kW	V/kVAR	
DER1	0.03	0.0006	0.0005	0
DER2	0	0	0	0
DER3	0	0	0	0.03

Figure 45: Example 2 of Grid Needs and DER Sensitivities under Abnormal Switching

Figure 45 shows abnormal switching causing DER3 to be transferred to Feeder 2. The sensitivities for DER3 have now changed based on the grid needs it is able to support under the new topology. Additionally, if DER1 and DER3 had been aggregated as an ADER in the as-built topology previously to help with Need 1 and Need 2, that ADER should be reconfigured to most efficiently address the grid needs under the new abnormal topology.

14 Appendix B: IEEE 2030.5 Considerations and Custom Extensions

The following list outlines other technology considerations that supported the longer-term use of IEEE 2030.5 in context of DER interoperability with the DERMS:

- IEEE 2030.5 is based upon the Internet protocol:
  - No application layer knowledge required at the gateways – can implement standard Internet routers
  - Allows for end-to-end security using TLS 1.2
  - Allows for multiple link layer technologies (e.g. Wi-Fi, ethernet, cellular)
- IEEE 2030.5 implements a RESTful HTTP interface:
  - Mature interface that is well understood and stable
  - Little risk of stranding assets or not being able to reuse interface code, if desired.
  - Easy to implement by a wide body of developers
- IEEE 2030.5 mandates the use of TLS 1.2 Security (HTTPS):
  - Same foundational security layer as used in standard Internet banking
  - Meets US National Institute of Standards and Technology (NIST) ECDHE Suite B requirements
  - All devices have certificates
- IEEE 2030.5 is based upon IEC 61968 Common Information Model:
  - IEC 61968 has widespread usage around the world in context of "Smart Grid" and leverages international developments and extensions
  - Where gaps existed in IEC 61968, IEC 61850 was included (IEC 61850-90-7 is the foundational model that has been used for all smart inverter functionality[39,40]).

14.1 Protocol Custom Extensions

As stated earlier, IEEE 2030.5 could not implement all the functionality required to perform the stated use cases. Custom extensions were needed for implementing the day-ahead market, the hourly ad-hoc market, time series controls, and flexibility reporting. Table 12, Table 13, and Table 14 describe the new extensions created for different parts of the process.

Table 12: New Data Objects for the Day-Ahead Process

[39] http://smartgrid.epri.com/doc/20150821/4_2015%20Industry%20Standards%20and%20Trends%20Integrating%20DER%20in%20US%20and%20Europe.pdf

[40] http://xanthus-consulting.com/Publications/documents/Advanced_Functions_for_DER_Inverters_Modeled_in_IEC_61850-90-7.pdf

IEEE 2030.5 Data Type	Extension	Purpose
DERControlBase	Add opModFlexibilityRequest control mode	For the DERMS to request flexibility offers
FlowReservationRequest	Modify to create a new data type to enable flexibility offer	For the aggregator to submit flexibility offers in the day-ahead process
FlowReservationResponse	Modify to create a new data type to enable flexibility award	For the DERMS to provide flexibility awards
FlowReservationRequest	Modify to enable submittal of forecasted flexibility	For the aggregator to submit flexibility forecasts
FlowReservationRequest	Modify to create a new data type to enable submittal of delivered flexibility	For the aggregator to submit delivered flexibility data
FlowReservationRequestList, FlowReservationResponseList	Modify to list flexibility offers, flexibility awards, flexibility forecasts and delivered flexibility reports	To list new data objects

Table 13: New Control Mode for Intra-Day Dispatch and Flexibility Forecast

IEEE 2030.5 Data Type	Extension	Purpose
DERControlBase	Add opModEnergize, with the value 1 for effective connect and 0 for effective disconnect[41]	For the DERMS to request the connection to, or disconnection from, the PCC of all actual DERs belonging to an Aggregated DER.
DERControlBase	Add opModDispatchDeltaGenW	For setting the DER control at an incremental or decremental (negative) delta generation level as a percentage of the name plate rating of the aggregated DER
DERControlBase	Add opModFlexibilityRange	For reporting the forecasted range of flexible power and storage energy

Table 14: New Data Objects for Time Series

Extension	Purpose
Add a DERDispatch data type to hold a time interval	For constructing a time series of DERControl values

[41] To effectively connect means for all the physical DERs underlying an aggregated DER to electrically connect to their respective PCCs and either enter the default control mode absent of the utility dispatch and execute utility dispatch. To effectively disconnect means for all the physical DERs underlying an aggregated DER to cease inject and withdraw of active and reactive power from their respective PCCs.

and zero or more DERControlBase values	
Add a DERSchedule data type to hold one or more DERDispatches and a DERType	For the DERMS to exchange DERControl values in a time series
Add a DEROffer datatype to hold a DERDispatch and offer price for the time interval	For constructing a time series of DER flexibility offer

15 Appendix C: Ad-hoc and Day-Ahead Market Flow Charts

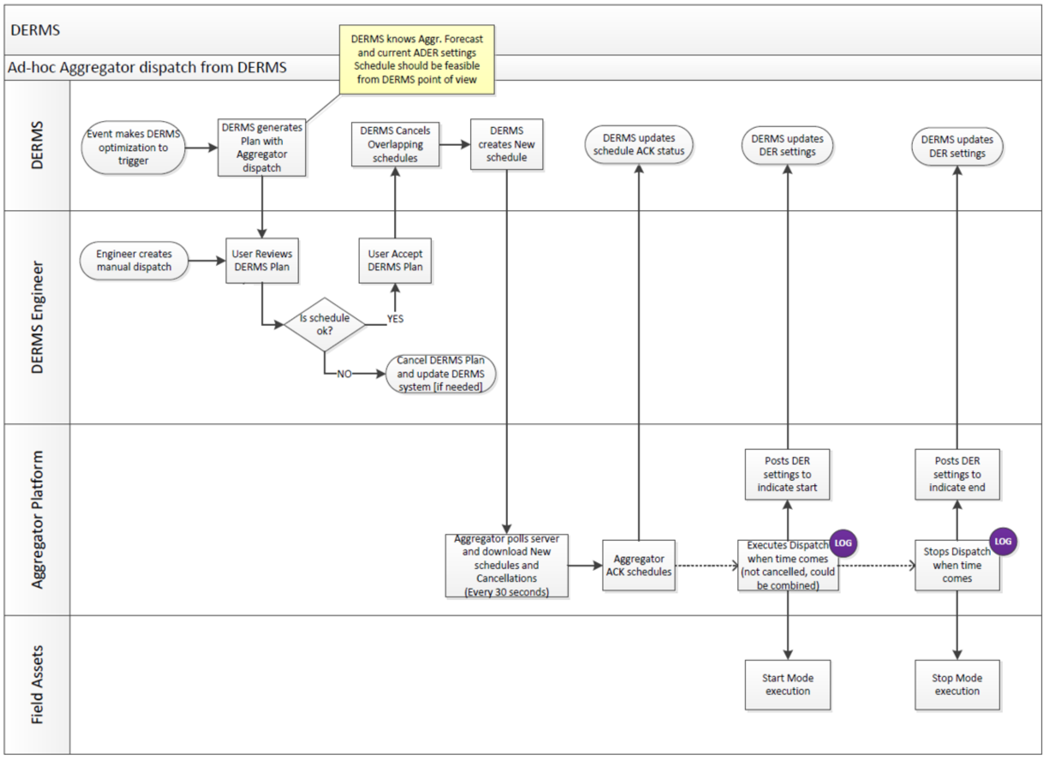


Figure 46: DERMS Hourly Ad-hoc Market Flow Chart

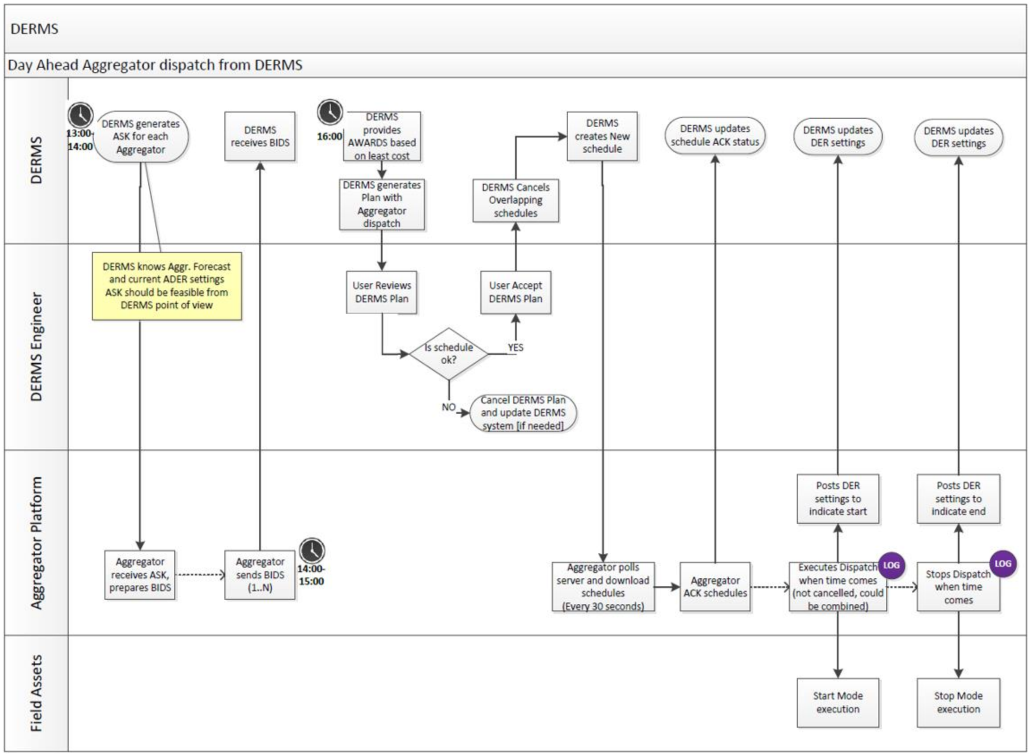


Figure 47: DERMS Day-Ahead Market Flow Chart

16 Appendix D: MAPE

Many of the tests regarding situational awareness compared the calculated real-time or forecasted power flow values via DERMS and CYME to the actual field measurements. In general, Mean Average Percent Error (MAPE) was used as the metric to compare the calculated versus actual values as given by Equation 1:

$$MAPE = \frac{100\%}{N}\sum_{t=1}^{N}\left|\frac{Actual_t - Calculated_t}{Actual_t}\right|$$

Equation 1: Mean Average Percent Error (MAPE)

While MAPE is a common method of comparison, it should be noted that there are potential drawbacks to using this metric. Because the results are given in percentages, these can be skewed by the size of the number being measured versus the actual difference in value. Because the team was comparing different types of values from different locations on the circuit, there was a wide range of magnitudes. For example, if comparing a calculated value of 99A to an actual 100A, the MAPE is 1%, but if comparing a calculated value of 9A to an actual 10A, even though the difference is still the same (1A), the MAPE is now 10%. This is particularly important given the relatively low resolution of some of the field measurements like amps and voltage, or when there may be SCADA dead bands in place to reduce communications traffic.

Beyond looking at one particular metric, there often needs to be a holistic approach to verifying the power flow results. This may depend on the importance of the measurement location, and the magnitude of the issue. This includes looking beyond the basic percentages to include the convergence of power flow sections, magnitude changes, and error bands.

17 Appendix E: Unbalanced vs Balanced Power Flow Results

Figure 48 shows the improvement in MAPE at different locations on the feeder when using CYME to model a balanced system (red) vs and unbalanced phased system (blue).

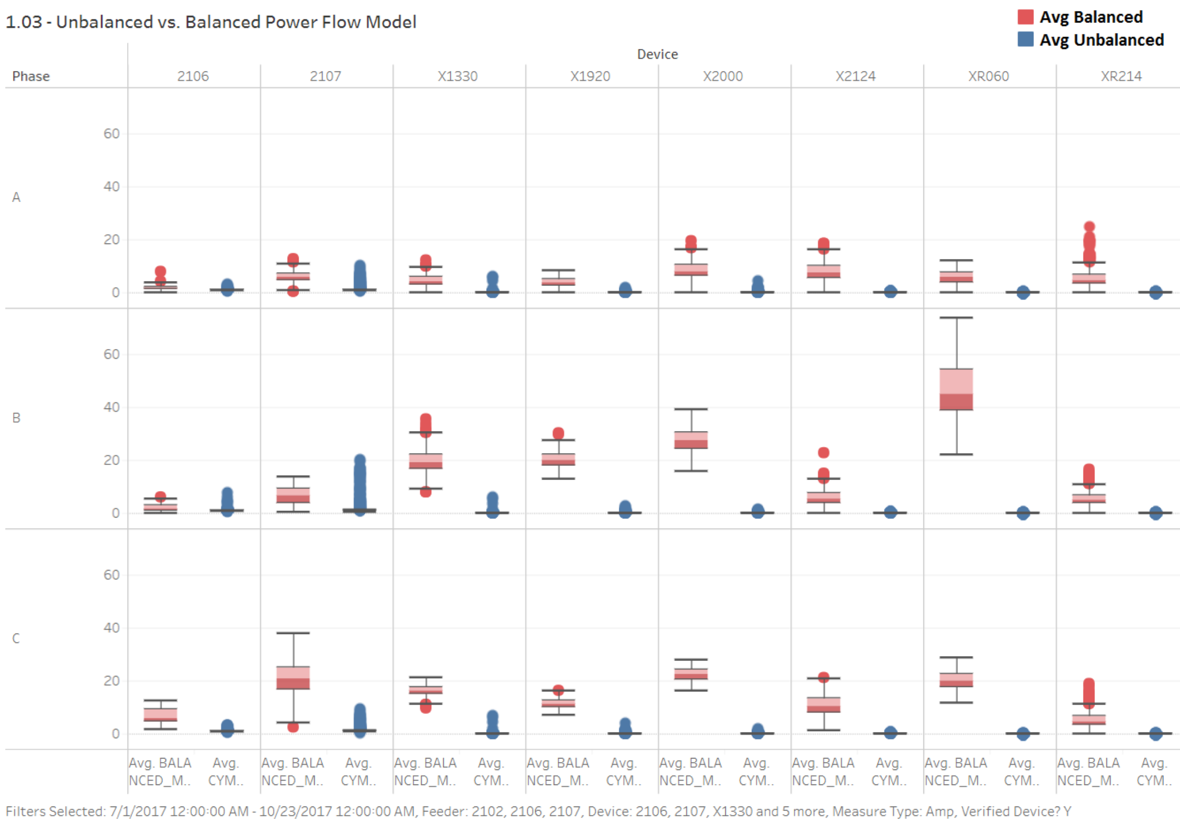


Figure 48: Balanced vs Unbalanced MAPE – Multiple Devices 7/1/17-10/23/17

As expected, certain types of values that are not phased, such as total 3-phase watts, have little to no impact from having phasing information (Figure 49).

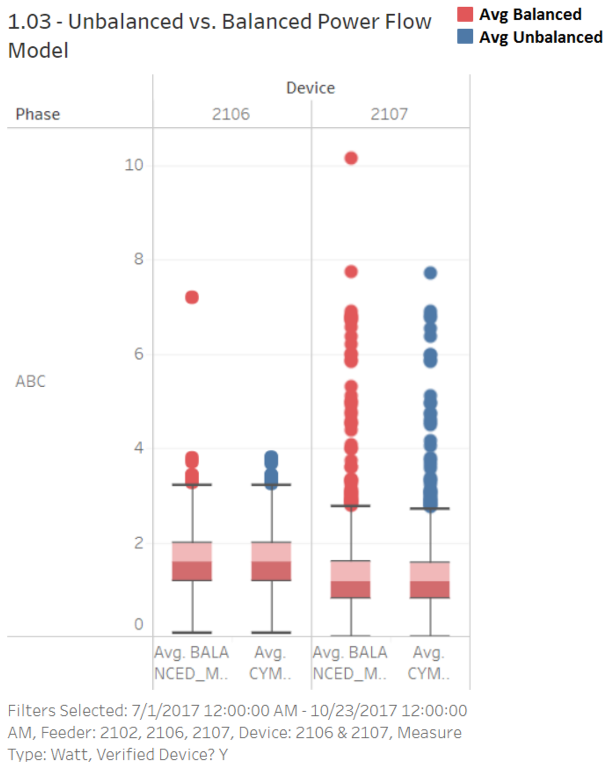


Figure 49: Balanced vs Unbalanced MAPE – 3-phase kW 7/1/17-10/23/17

Figure 50 shows the comparison between the DERMS ADMS, CYME, and field measurements with the inclusion of PMU data over the course of two days for every 5-minute power flow run with the YB BESS participating in the Frequency Regulation Market. The green boxed devices were used for load allocation.

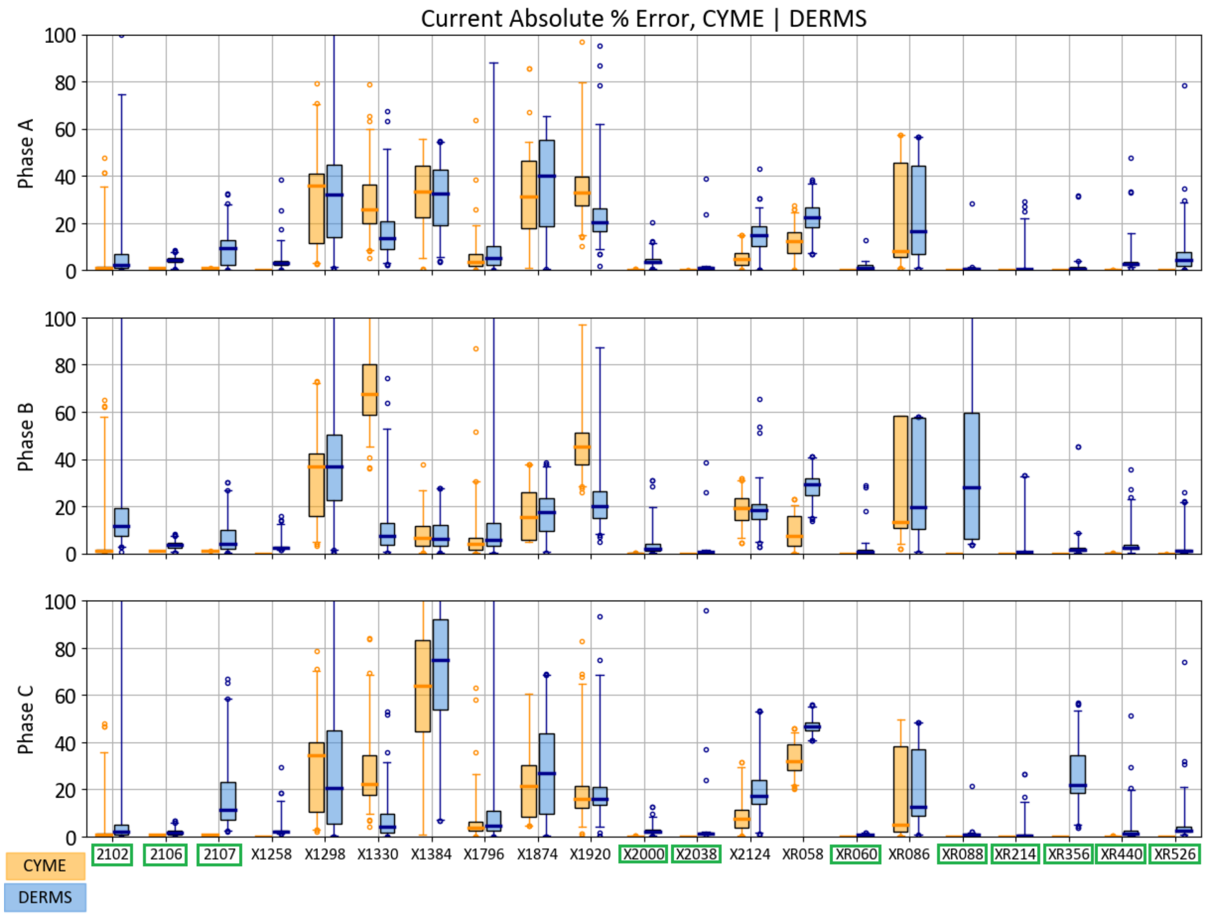


Figure 50: Unbalanced Power Flow Comparison of Amps at Multiple Devices over 2 Day Period in March 2018 using PMU Data

18 Appendix F: Forecasting Analysis

Figure 51 shows a comparison of the forecast values versus the time of day for the two feeders not serving the YB BESS. Since MAPE is percentage based, the error percentage is larger for times where load measurements were generally smaller.

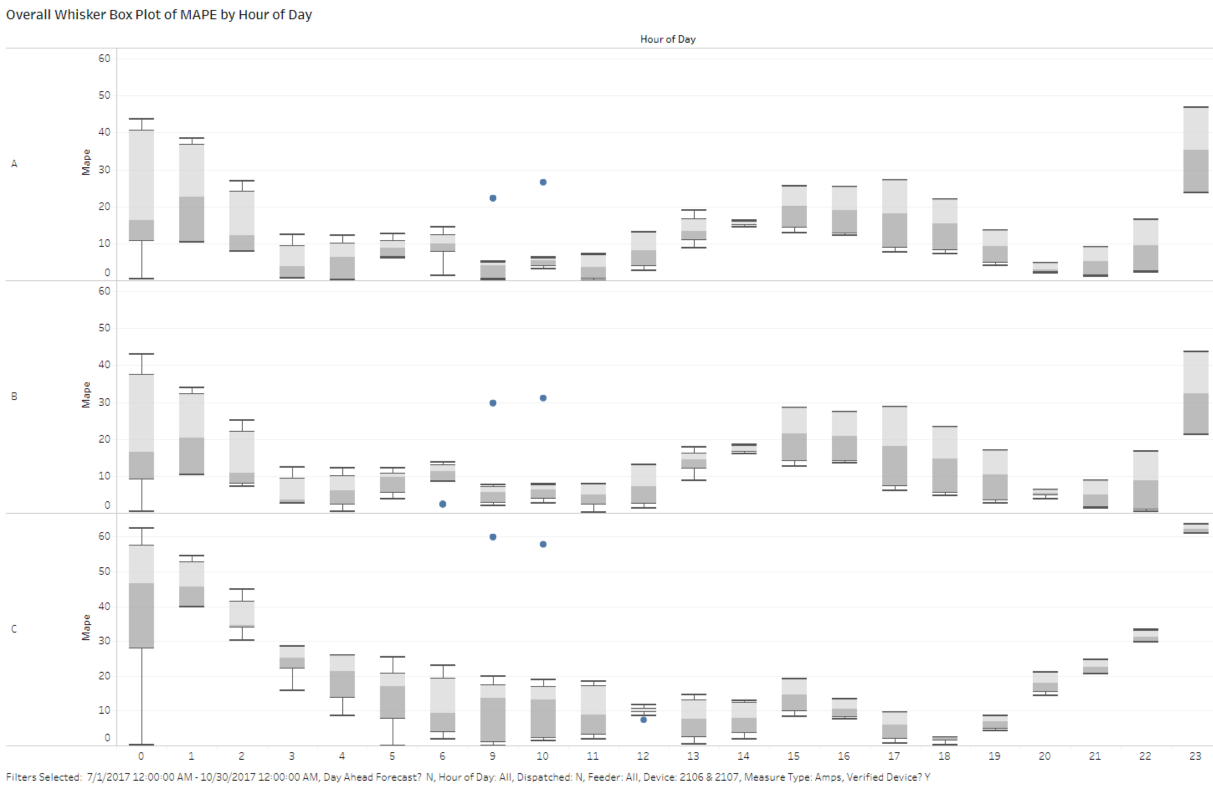


Figure 51: Feeder Head Forecasted Amps MAPE by Hour of the Day – 7/1/17-10/30/17 – Not including YB BESS Feeder

The impact of the YB BESS in the Frequency Regulation Market made it very difficult to forecast as shown by the high MAPE values in Figure 52.

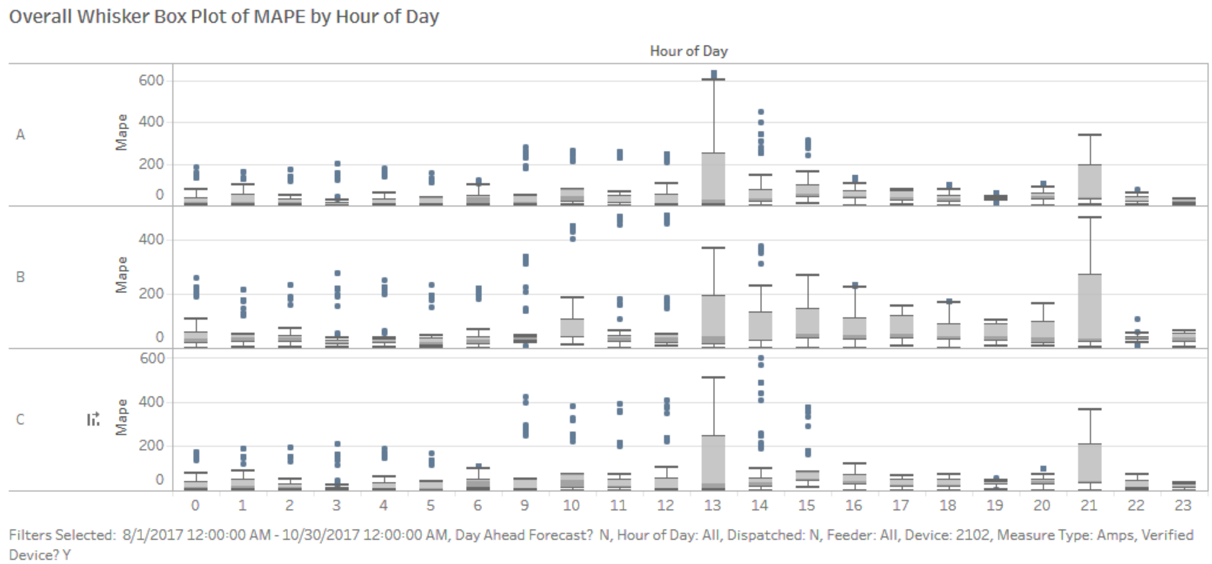


Figure 52: Feeder Head Forecasted Amps MAPE by Hour of the Day – 8/1/17-10/30/17 –YB BESS Feeder Only

Accuracy by hour of the forecast was also evaluated, with Figure 53 showing the generally expected trend of the more immediate forecast hours having better accuracy than hours farther in the future.

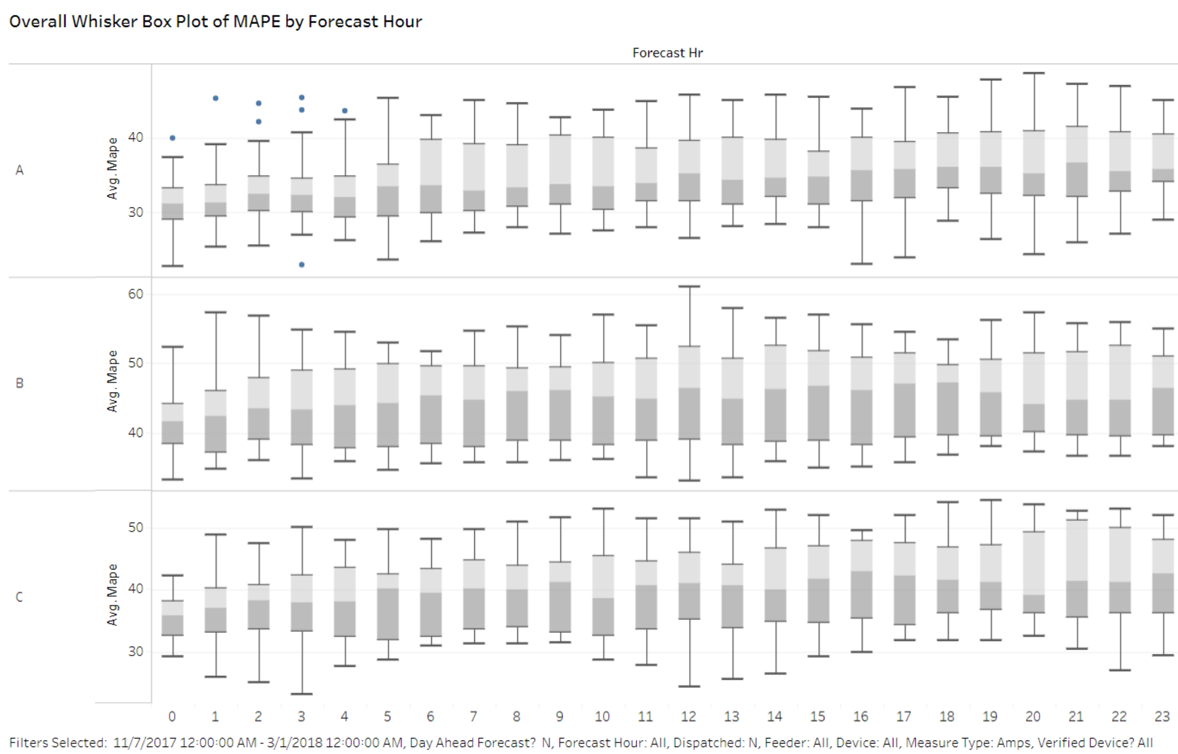


Figure 53: All Devices Forecasted Amps MAPE by Hour of the Forecast – 11/7/17-3/1/18

19 Appendix G: Commercial Storage Only ADER Flexibility Forecasting

There are inherent complexities in forecasting energy storage because future flexibilities can change based on dispatches, and one can operate the storage in a way to prepare for known future dispatches. Therefore, aggregators need to provide an accurate starting point for potential future dispatches and forecast accurate constraints of the system in the longer term.

For the storage only ADERs, the battery control system flexibilities provided an initial SoC and bound a DERMS dispatch within the constraints of their non-export interconnection agreement and customer demand charge management impacts. For example, Figure 54Figure 10 shows that up flexibility (generation) is constrained during the late evening and early morning periods when loading at the site would be lower to conform with non-export limitations. Similarly, down flexibility (added load) is constrained during periods that could negatively impact the customer's demand charges.

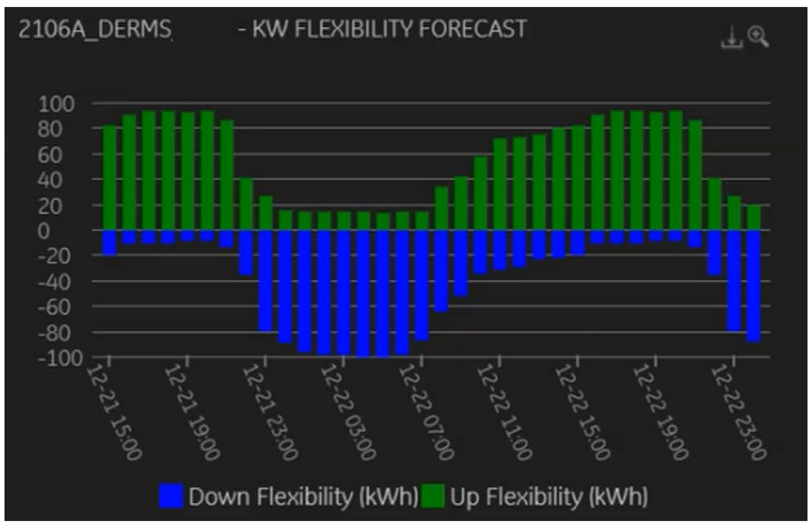


Figure 54: Commercial Storage Aggregator Provided Flexibility Example

The DERMS uses the initial SoC and known capacity limitations of the storage to dispatch within these bounds. For example, it would be incorrect to read Figure 10 as the storage asset being able to provide 90kWh of generation for hours 16-21; the DERMS knows the actual 240kWh capacity of the unit could not provide 90kWh for 5 hours (450kWh) and would manage the SoC to dispatch within those constraints to best meet its objectives.

The SoC or available capacity of the storage determines the available flexibility for the energy storage asset. Figure 55 shows the correlation between measured capacity and available flexibility for one ADER site over a 2-week period.

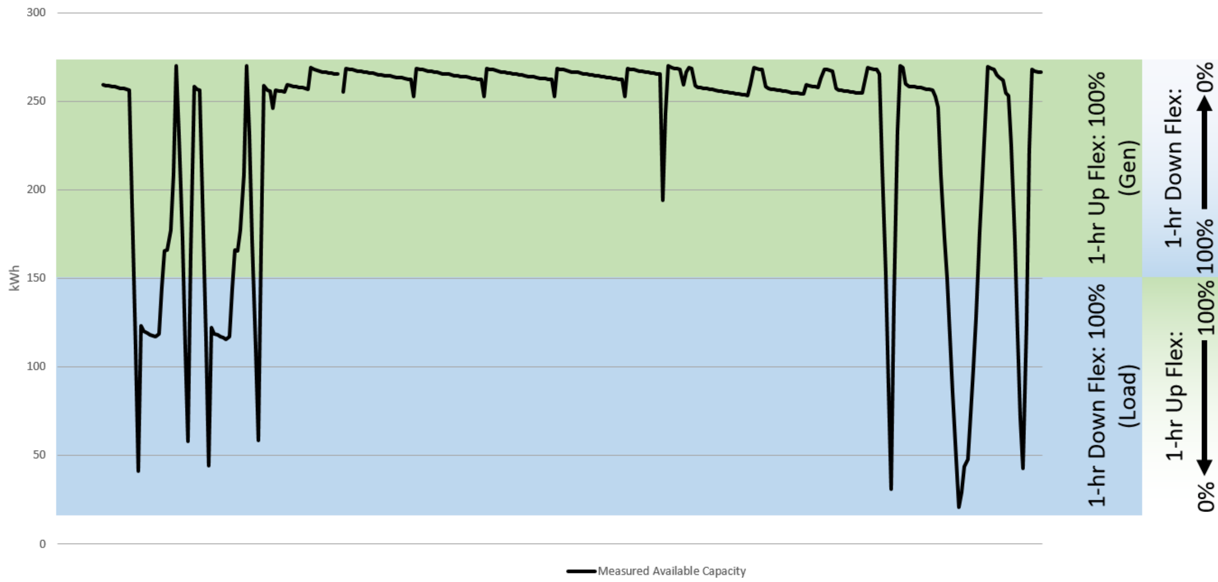


Figure 55: Flexibility Impacts of the Measured Available Capacity for Storage Only ADER Site 1 over 2-week Sample Period for Storage Only ADER Site 1

In addition to the bounds given by the flexibility, because the DERMS is managing the SoC of the storage asset, the initial SoC given with the flexibility is very important. For the DERMS Demo, this flexibility and SoC information was updated hourly. This allowed some ability for the energy storage operator to adjust the SoC over the course of the hour to make up for any inaccuracies in the SoC forecast before a DERMS dispatch. However, the amount of possible correction was limited by the capabilities of the device and premise constraints such as demand charge management and non-export interconnection agreement. Therefore, for the given 120kW assets, if the SoC was inaccurate by more than ~120kWh, there wouldn't be enough time to correct the SoC before a DERMS dispatch in the first hour. Figure 56 shows the percentage of time the hour the actual capacity and forecast capacity align within the correction capabilities over a two month period. This would be most relevant for the immediate hour dispatch, where beyond that the energy storage provider could potentially correct for any future dispatches.

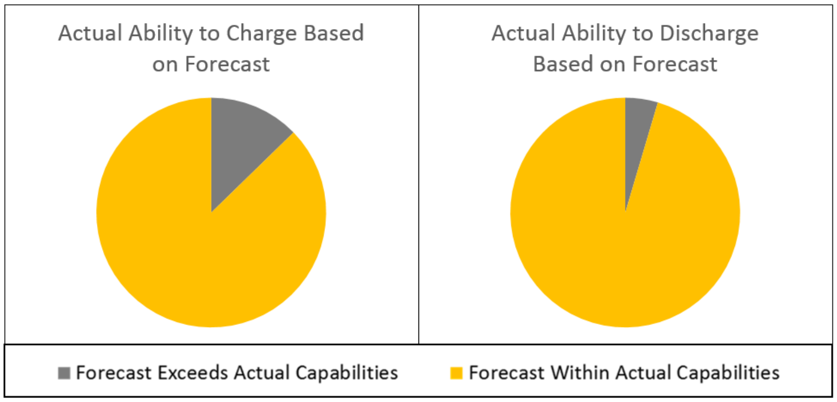


Figure 56: Commercial Storage Analysis of 1-Hr Ahead SoC Error Comparing Actual Capacity to Forecast Capacity

Figure 57 shows the forecasted flexibilities and calculated actual flexibility capabilities over multiple days to highlight how the vendor intentionally de-rated their ability to provide generation during the late night and early morning hours to avoid export to the grid, per their interconnection rules.

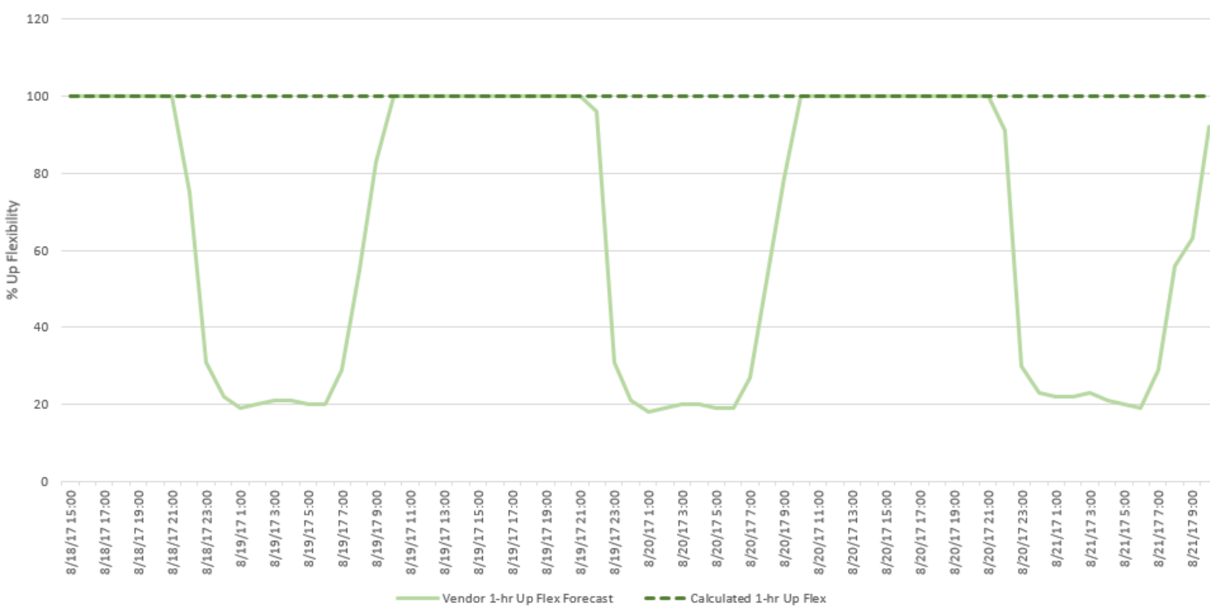


Figure 57: Vendor Forecasted and Actual Calculated Up Flexibility over 3 days for Storage Only ADER Site 2

The coordination capabilities required for a vendor to manage interconnection as well as customer constraints are important when providing flexibilities to a DERMS. While there is room for improvement particularly in short-term forecasting, the vendor was able to respond to the DERMS dispatches during testing. It is expected that as vendors gain experience with these types of systems, algorithms would improve in the future.

20 Appendix H: Combined Solar and Storage ADER Flexibility Forecasting

The residential combined solar and storage assets used for the DERMS Demo did not require the complex coordination for demand charge management or non-export interconnection constraints of the commercial storage assets (Section 0 - Appendix). This reduced the complexity required, however, they did need to incorporate solar forecasting into the flexibility. The residential storage was not providing any customer services during the DERMS demo, so the full flexibility of the battery was given to the DERMS which made the storage forecasting relatively simplistic. The additional down flexibility provided by potential solar generation curtailment was integrated with the base storage flexibility resulting in a flexibility profile that often took a “bus” shape (Figure 58).

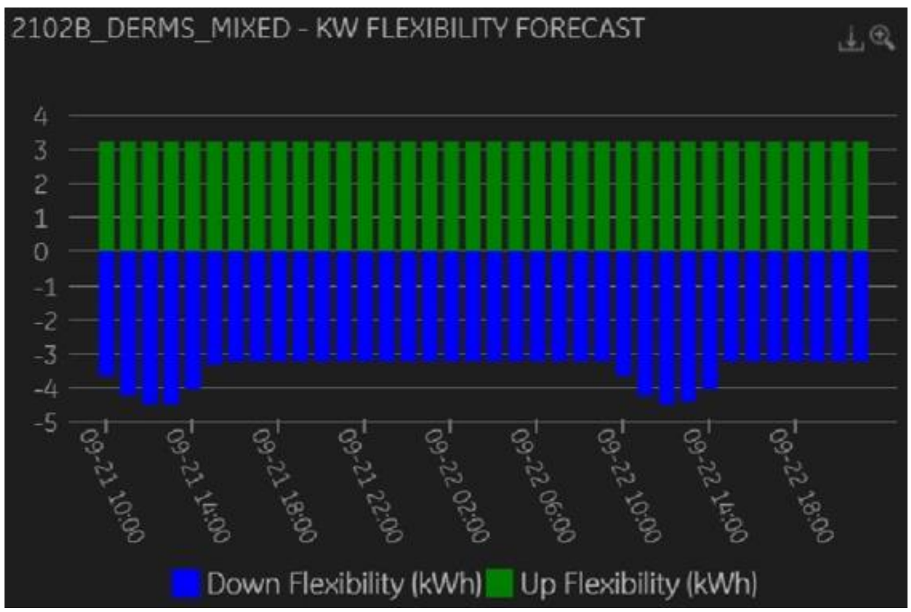


Figure 58: Residential Solar+Storage Aggregator Provided Flexibility Example

Similar to the discussion in Section 0 - Appendix, the flexibility provides bounds from which the DERMS can control the asset given an initial SoC. There is no standard methodology for how a vendor may forecast flexibility and SoC to a DERMS, and therefore there can be significant differences in vendor implementation and accuracy. Issues with aggregator solar forecasts of the DER aggregators led to the methods of dispatch described in Section 7.3.5.2. Additionally, the residential aggregations grew over the course of the demonstration as more assets were added, and particular attention needed to be placed on updating aggregated flexibilities as new members came online.

The forecasted and actual state of charge of the solar plus storage DERs within a rolling one-hour ahead flexibility forecast was analyzed over a 2-month window. Similar to the commercial storage only vendor, if the error went beyond the capabilities of the underlying assets to correct within the hour then it could create potential issues in the immediate next hour dispatch (Figure 59).

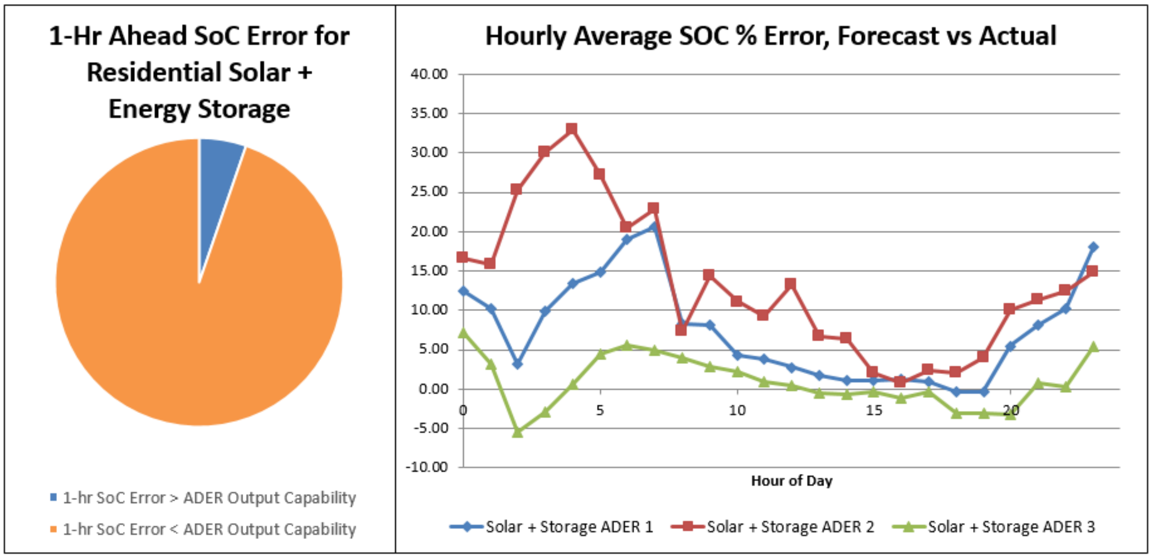


Figure 59: Residential Solar + Storage Aggregator Analysis of 1-Hr Ahead SoC Error

The forecasts have room for improvement based on the results of the DERMS Demo, but the vendor was able to respond to requested DERMS dispatches. As discussed earlier, given enough vendor control and capabilities, the nature of storage provides the ability to address potential errors in initial forecasting in a longer time frame. It is expected that as vendors gain experience with these types of systems, forecasting algorithms would improve in the future, especially if there are consequences in a production system if a DER did not fulfill a dispatch request within their given flexibility.

21 Appendix I: Comparison of Wholesale Pricing with Feeder Loading at PG&E

Spearman correlation coefficients were calculated to compare hourly CAISO Pricing Node (Pnode) energy prices at each distribution feeder to the hourly loading of the feeder. These coefficients can indicate whether the price and loading changes are highly positively aligned (0.5 to 1.0) or highly negatively correlated (-1.0 to -0.5), meaning price and load changes move in opposite directions. The goal was to directionally confirm that there should be minimal times when feeder loading may be impacted negatively by wholesale energy prices. Figure 60 shows that less than 5% of all hourly correlation coefficients for the evaluated distribution feeders from July 2017-June 2018 were less than -0.25. This contrasts with 65% of correlation coefficients greater than 0.25, indicating general alignment between wholesale energy pricing and distribution loading.

The data processed for this study looked at more than 800,000 hourly correlation coefficients, which was deemed sufficient for this particular analysis.

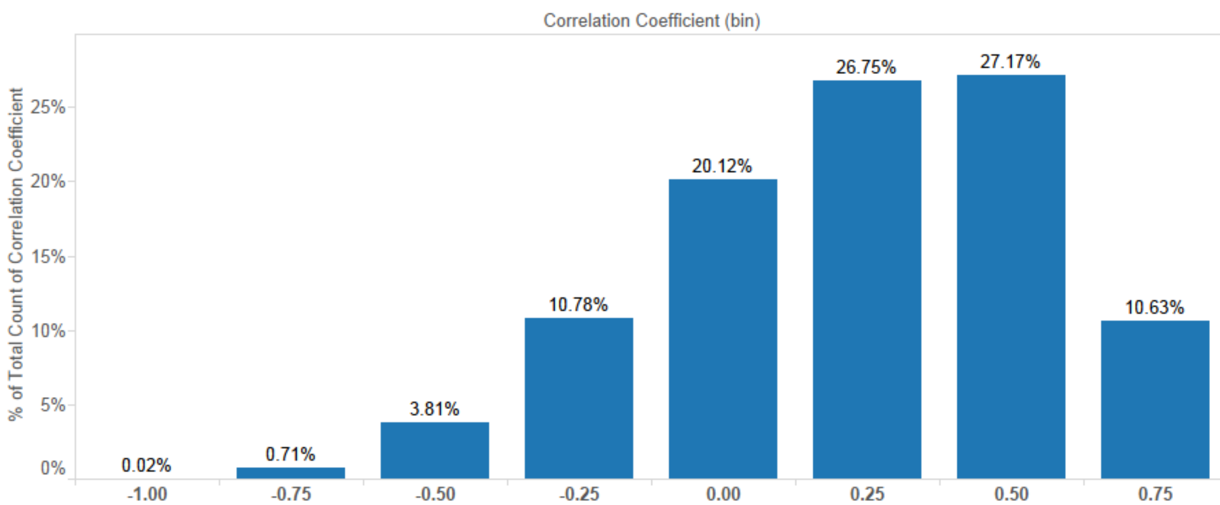


Figure 60: Histogram of Hourly Spearman Correlation Coefficients Comparing Feeder Load and the Associated Pnode Pricing

These correlation coefficients can vary based on feeder, time of day, and month of the year. Figure 61 shows a heat map based on the hourly correlation coefficients to give an average 24-hour profile per month for all the feeders under study. The red color coding highlights times when feeders load and energy pricing are more negatively correlated.

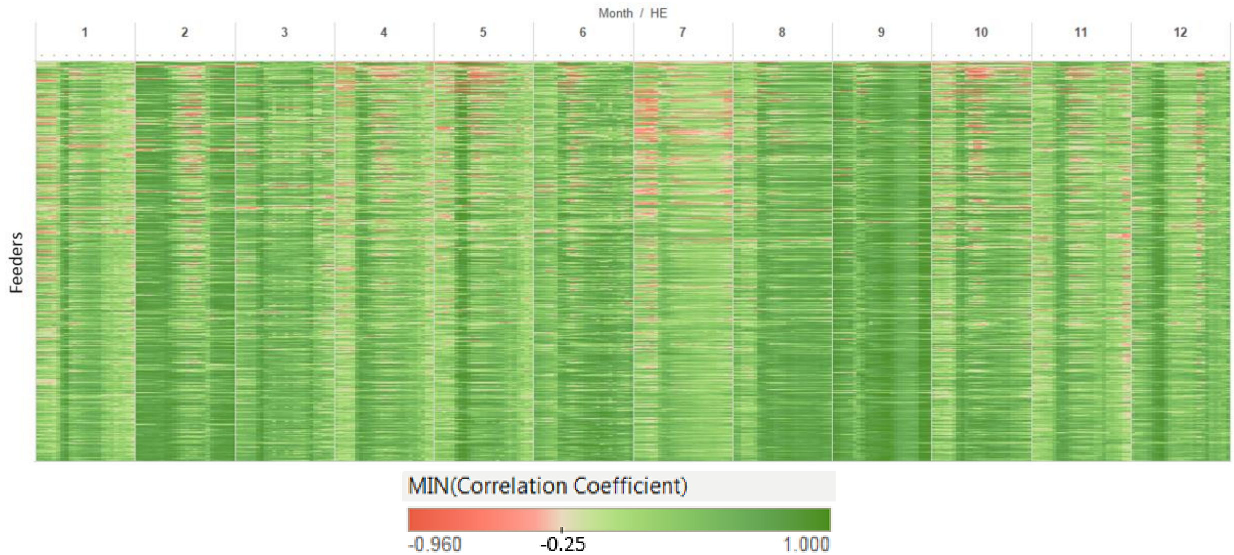


Figure 61: Heatmap of Average Correlation Coefficients per 24-hour Period of Each Month for All Evaluated Feeders

22 Appendix J: Analysis of Priority Structures Required for Distribution Services

22.1 CAISO Energy Pricing Aligns with Distribution Needs: Wholesale Only / Wholesale Priority

As shown earlier, when distribution needs and wholesale energy awards align, there may not be a need to prioritize distribution dispatches if assets are participating only in the energy markets. However, Figure 62 shows what may happen when the energy price and the feeder loading do not align. By time-shifting the LMP to simulate non-alignment, the YB BESS was incentivized to charge during the low-price hours, which in turn caused a violation both in the morning and evening hours.

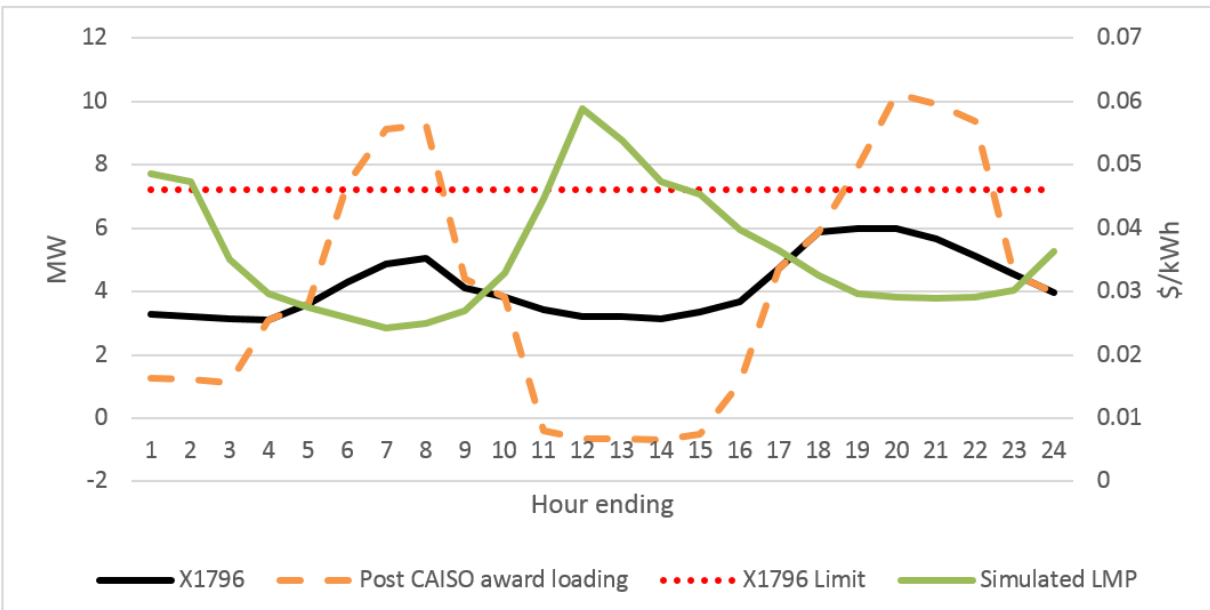


Figure 62: YB BESS Dispatch Causing Simulated Overloads when Wholesale Energy Prices Do Not Align with Feeder Loading

A similar conflicting price curve was provided to the aggregator to make bids of their BTM resources. The magnitude of the issue is much smaller due to the size of the resources relative to the feeder, but a close-up of the impact is illustrated in Figure 63.

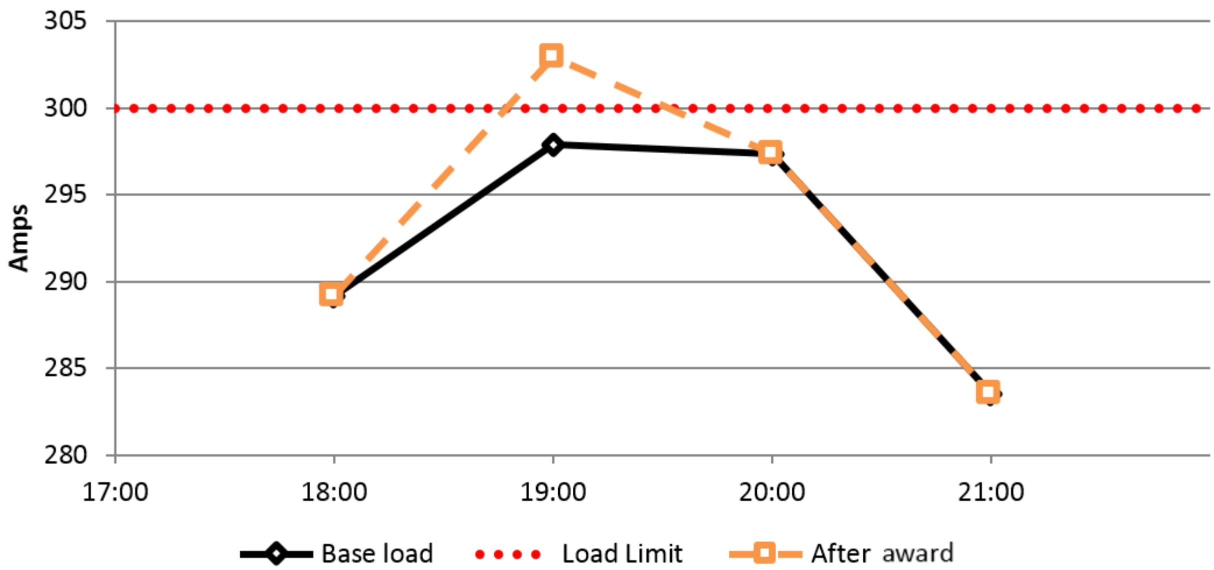


Figure 63: BTM Aggregator Resources Causing Simulated Overload when Wholesale Energy Prices Do Not Align with Loading

In both cases, the DERMS was unable to mitigate since the wholesale dispatch was intentionally given priority. If the DERMS was allowed to override a wholesale command, the violation may have been mitigated. This is relevant because as discussions of Multiple Use Applications evolve, rules governing how assets can be used are being developed, and it is important to consider how such situations, albeit rare, would be prevented.

22.2 CAISO Dispatch Conflicts with Distribution Needs: Distribution Priority

The next step in the progression would be to give distribution priority over wholesale to dispatch a resource actively to prevent a grid issue. For example, Figure 64 shows the successful mitigation when the DERMS was given priority to dispatch the YB BESS to prevent a forecasted overload in the evening.

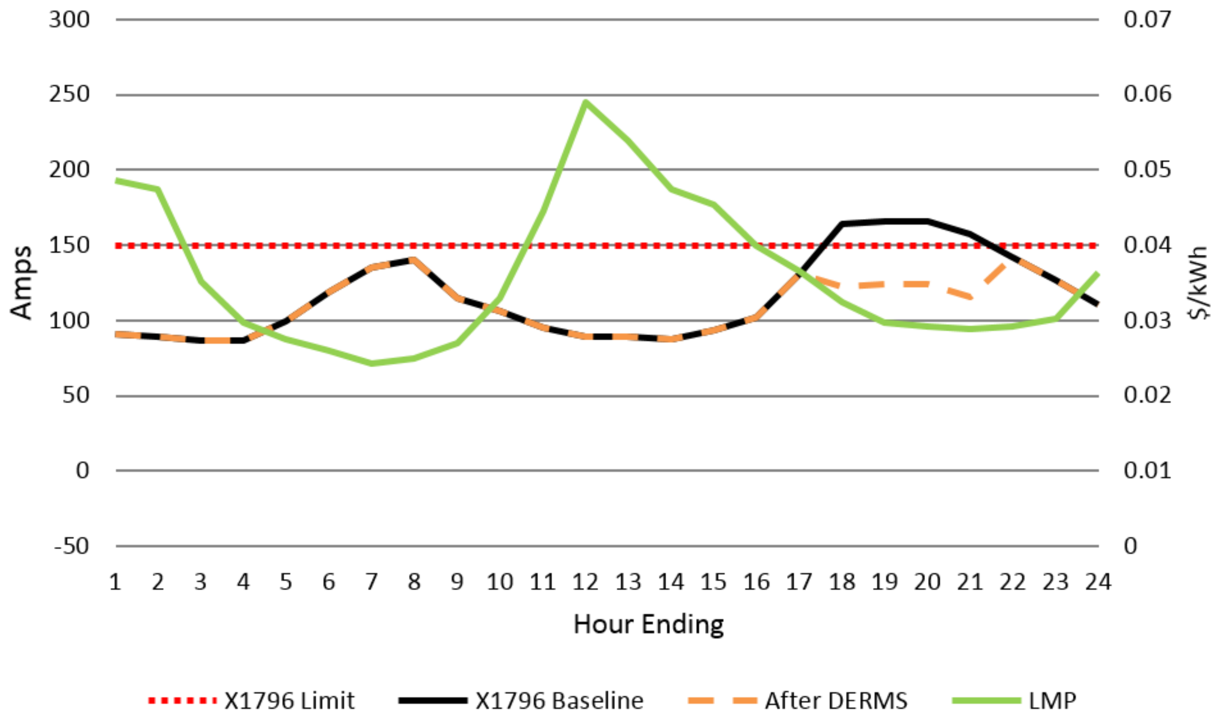


Figure 64: DERMS Priority Initially Resolving Overload Condition

However, when unregulated wholesale participation was allowed for all hours except for the DERMS dispatch hours, the higher prices on the tail ends of the original overload created new overloads around the DERMS mitigation (Figure 65).

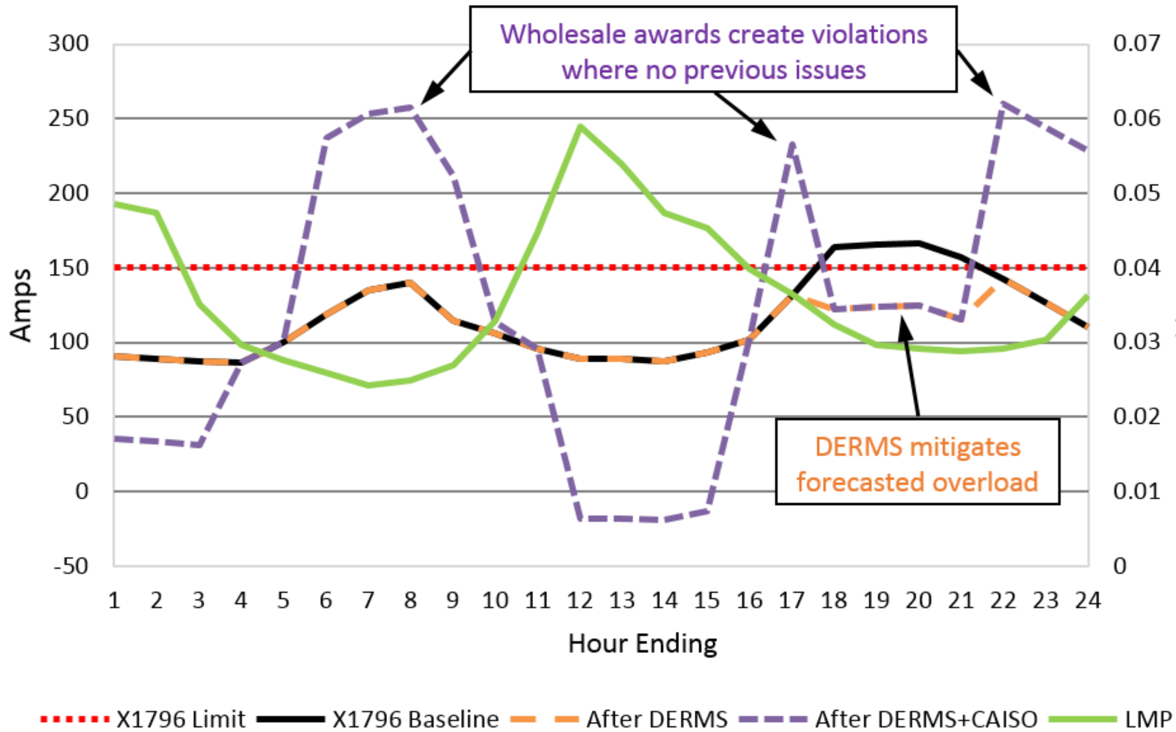


Figure 65: Even with DERMS Priority for Active Management, Wholesale Dispatch May Cause Additional Issues

22.3 CAISO Dispatch Conflicts with Distribution Needs: Constraints + Wholesale Priority

The next step in the progression was to allow distribution to provide constraints but allow the wholesale market to have priority for any active management dispatches. While this would resolve all issues for DERs coordinating with the DERMS, there would still be a gap when issues on the feeder were caused by DERs or other entities that were not participating with the DERMS, where the DERMS had to call on available resources to solve a problem they were not creating. This creates a potential issue if the wholesale dispatch uses up all available flexibility of the resources and there is not enough left to resolve any distribution issues created by other entities. Figure 66 illustrates if the YB BESS was operating within constraints and responding to wholesale signals but runs out of capacity before being able to mitigate the distribution issue.

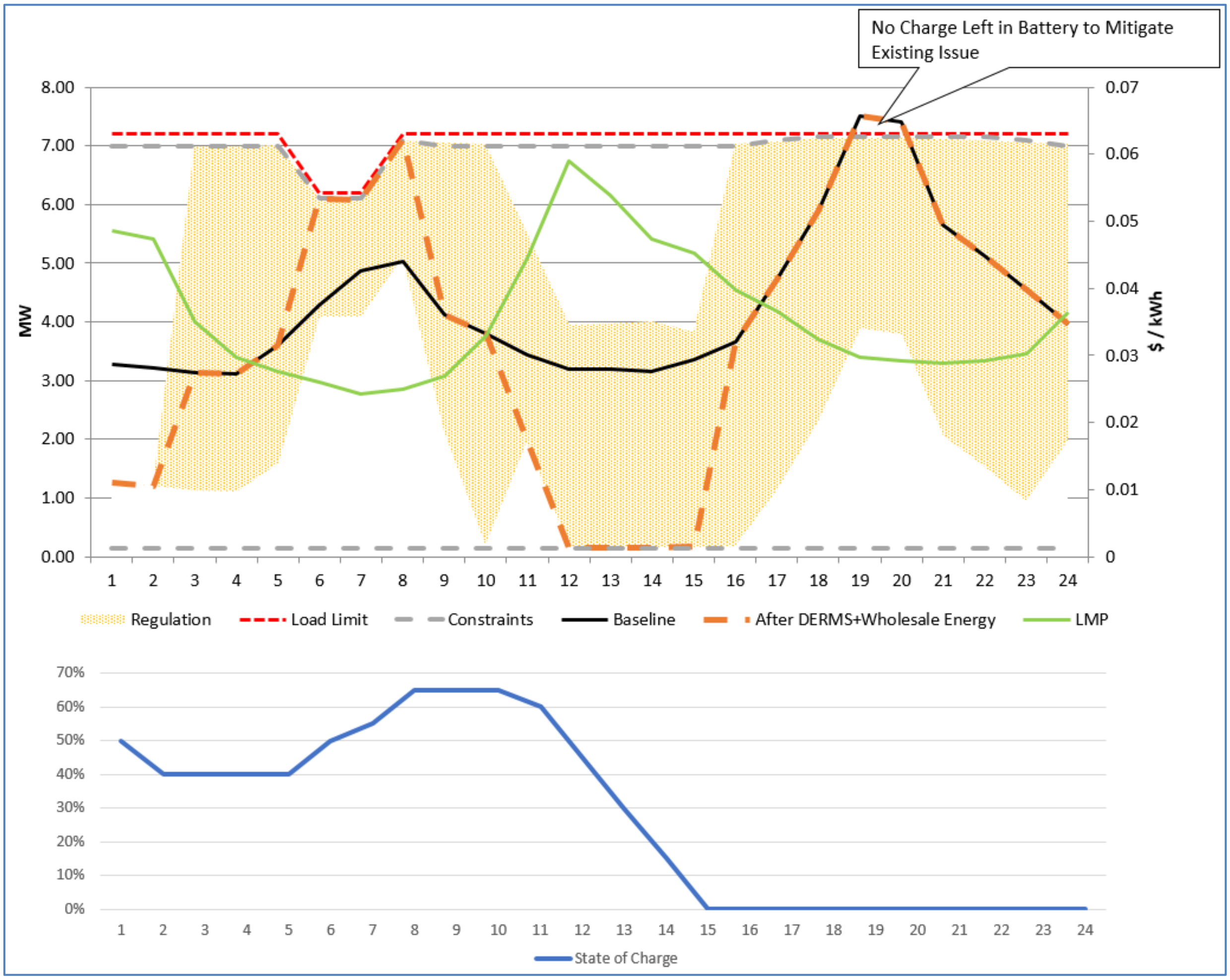


Figure 66: Illustrative Example of Insufficient Capacity to Mitigate Distribution Issues Caused by Others when Operating within DERMS Constraints and Wholesale Priority

22.4 CAISO Dispatch Conflicts with Distribution Needs: Constraints + Distribution Priority

This all leads to the final step in the progression, indicating that **to cover all potential edge cases, DERMS should have the priority to both issue constraints and active management dispatches above wholesale.** As shown by the decreasingly small number of edge cases, the actual impacts of this prioritization should be minimal, but warranted for the limited cases demonstrated. Figure 67 shows an illustrative example of mitigating the shortfalls demonstrated by Figure 66. The actual dispatch of YB BESS under these conditions is shown in Figure 68 causing no issues under the forward or reverse capacity limits, even under variations in the load limit. It should be noted that in rare cases the limits imposed by distribution may fall under "emergency ratings" versus the normal ratings for equipment. Therefore, **flexibility should be built into systems to account for these types of limits, especially if**

there are conditions where transmission must call on resources to prevent system failures outside the normal distribution ratings, but within the emergency ratings.

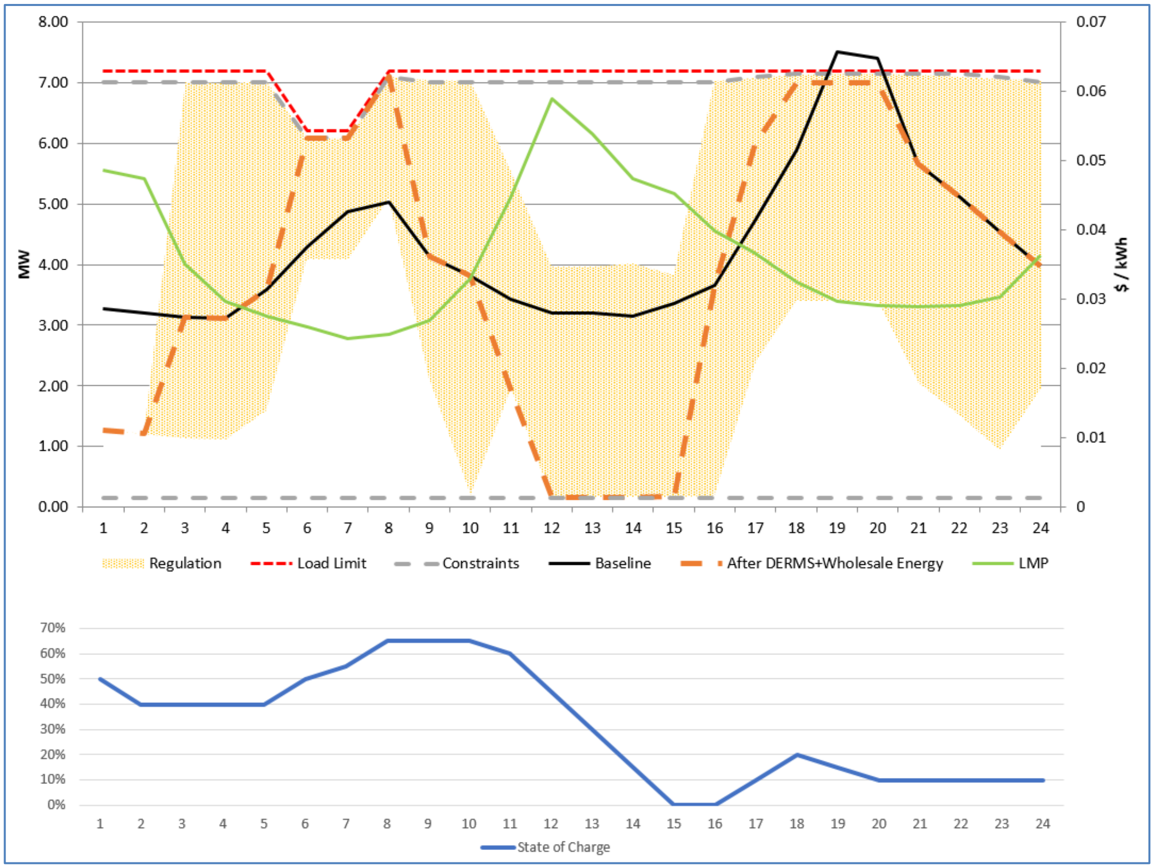


Figure 67: Illustrative Example of Distribution Priority for Constraints and Active Management Mitigating Issues

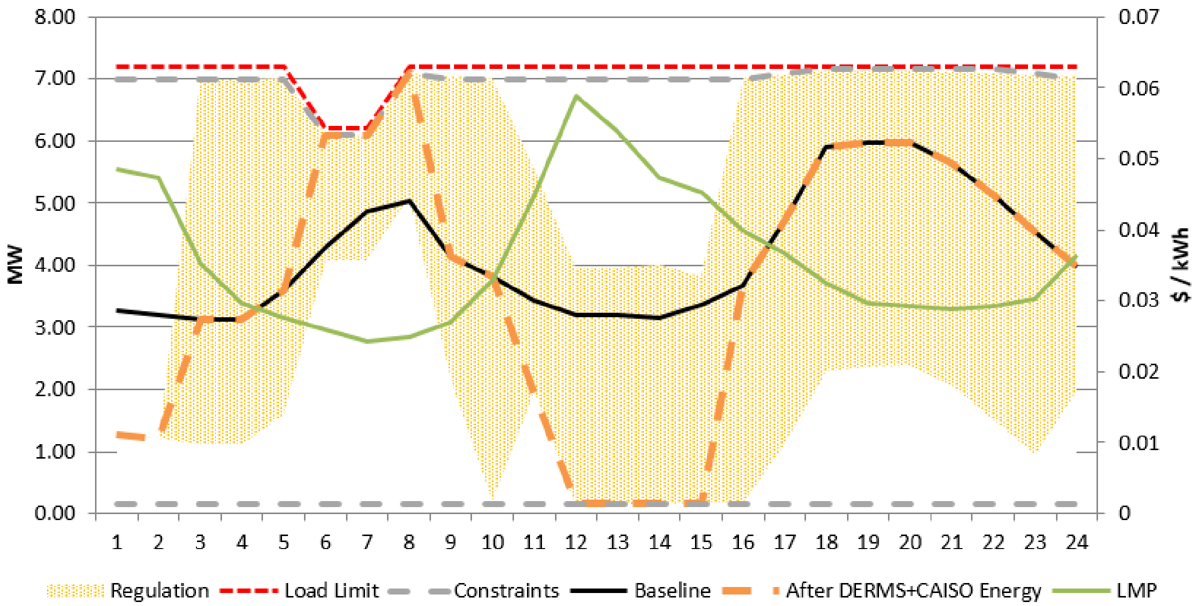


Figure 68: Actual Dispatch of YB BESS using Distribution Priority for Constraints and Active Management Causing No Issues Even with Load Limit Variations

23 Appendix K: Analysis of Potential DERMS Impacts on DR Settlement Calculations

The following study looked at the potential impact of a DERMS dispatch in calculating DR settlement based upon the performance evaluation methodology called Baseline Type-I as defined in the CAISO Demand Response User Guide v4.3. Referred to as ISO Type 1, this is “the most commonly used baseline method for performance measurement of demand response resources among ISOs and regional transmission organizations.” [42] While other settlement methods are approved, only this method was analyzed based on its stated ubiquity in the market.

The methodology creates a baseline using 10 historical “non-DR-event” days to create an average baseline profile. This average profile is then modified for the DR event window using a “day-of” multiplier (capped at ±20%) calculated during an adjustment period during the 3 hours starting 4 hours before the DR event. The multiplier is the ratio of the average load during this 3-hour window of the DR event day compared to this same window of the 10-day average baseline. The adjusted customer baseline is then used in the settlement process to compare against the actual loading during the DR event. Figure 69 provides an example of the process, and the modeled reference data used for this analysis. A DR event window was chosen for hours ending 18-21, and the corresponding adjustment period was for hours ending 14-16.

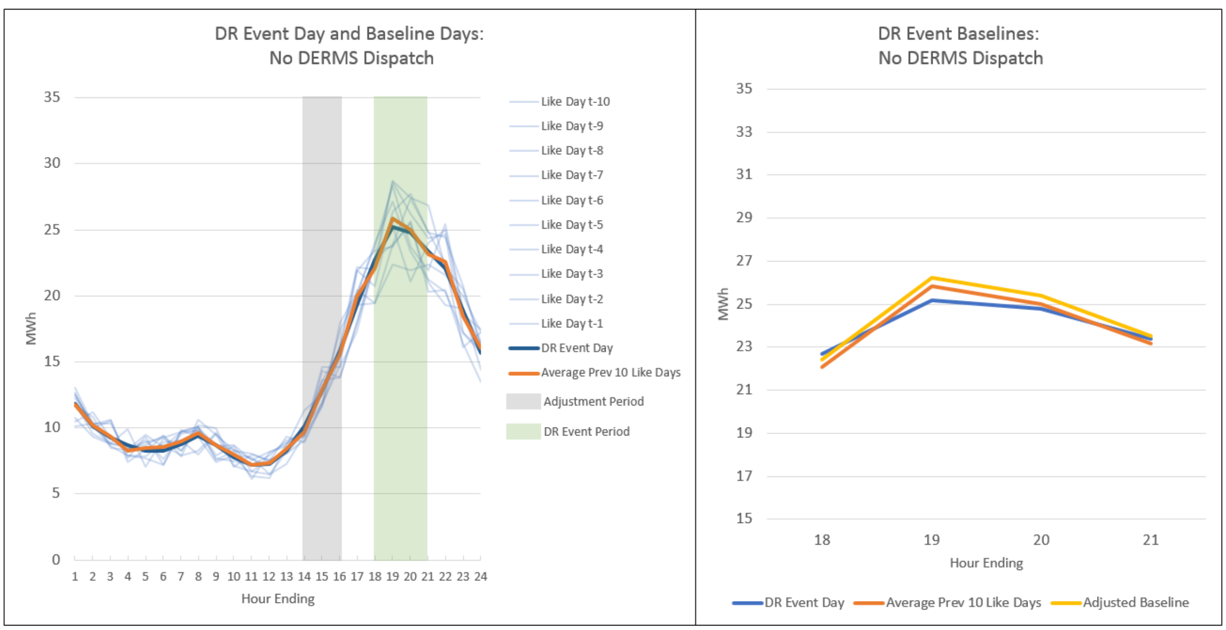


Figure 69: Example DR Baselining for Settlement using ISO Type-1 Methodology using Illustrative Data

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[42] http://www.caiso.com/Documents/DemandResponseUserGuide.pdf

The study compared the impact on the adjusted customer baseline under different types of DERMS dispatches. The goal was to give examples of potential types of dispatches that could either raise or lower the adjusted customer baseline. These dispatches could potentially be from a DERMS, another program, or even local customer control. The purpose of using a 10-in-10 baseline approach is to determine what a customer load would normally have been if it had not responded to a dispatched event. The ISO Type 1 baseline excludes previous DR event days because these days do not reflect what the customer load would otherwise have been. However, the CAISO does not recognize non-CAISO (e.g. distribution) dispatches when determining which days to exclude, meaning non-CAISO dispatches are included in the baseline calculation and can artificially bias the calculation. Because DR settlement is based on this adjusted customer baseline, lowering it would make it more difficult for a customer to meet a load reduction DR award, while raising it would make it easier to meet a load reduction DR award.

Lowering the Adjusted Baseline:

By not recognizing the effects of non-CAISO dispatches, there are three potential DERMS (or other non-CAISO) dispatches that could lower the adjusted baseline:

1. An increase during the day-of adjustment period time window during any of the 10 “non-DR-event” days used to create the historic baseline (Figure 70)
2. A decrease during the adjustment period time window during the DR event day (Figure 71 - example capped by the 20% limit)
3. A decrease during the DR event time window during any of the 10 “non-DR-event” days used to create the historic baseline (Figure 72)

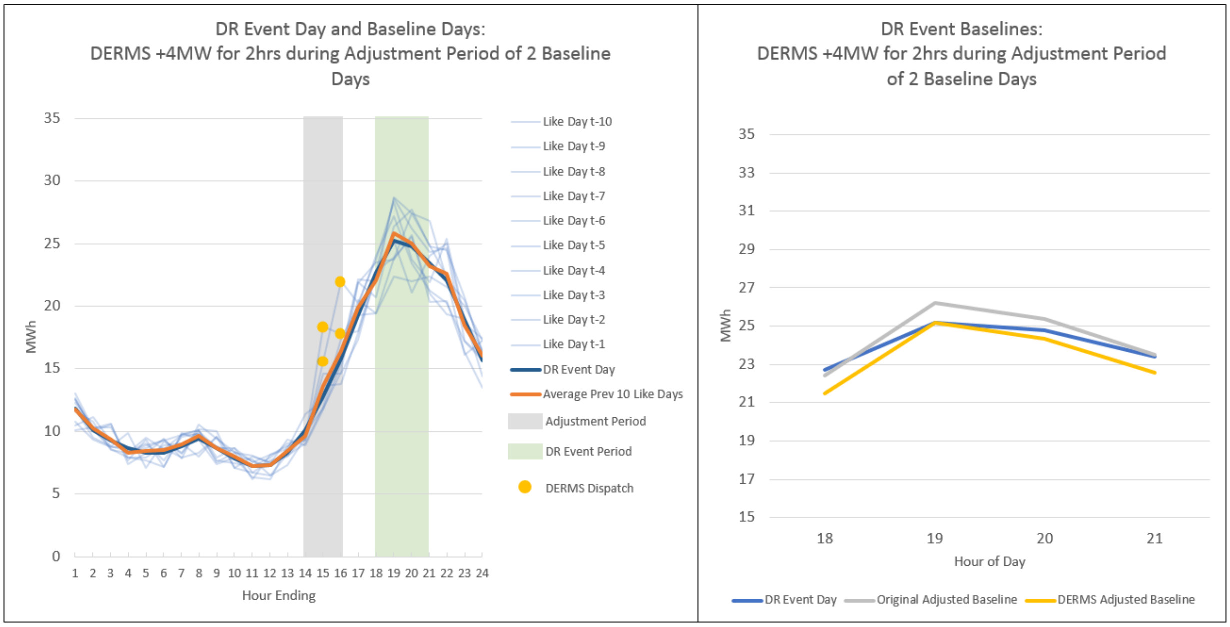

Figure 70: DERMS Dispatch Lowers Adjusted Baseline by Raising Load during the Adjustment Period on Historical Like Days

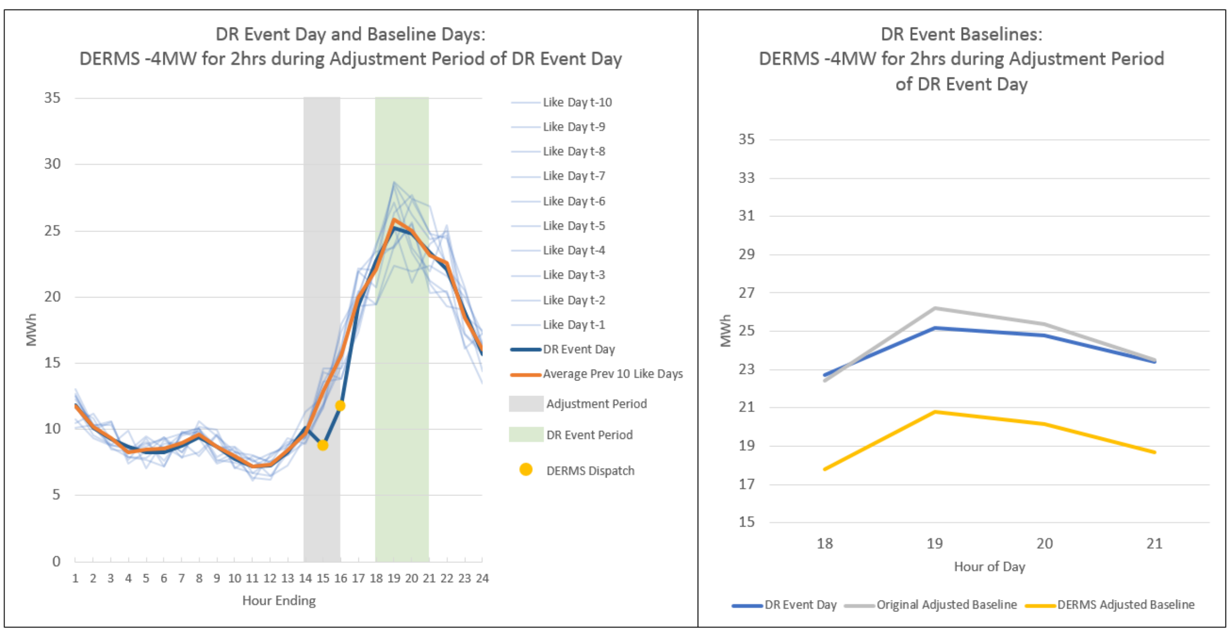

Figure 71: DERMS Dispatch Lowers Adjusted Baseline by Lowering Load during the Adjustment Period on the DR Event Day

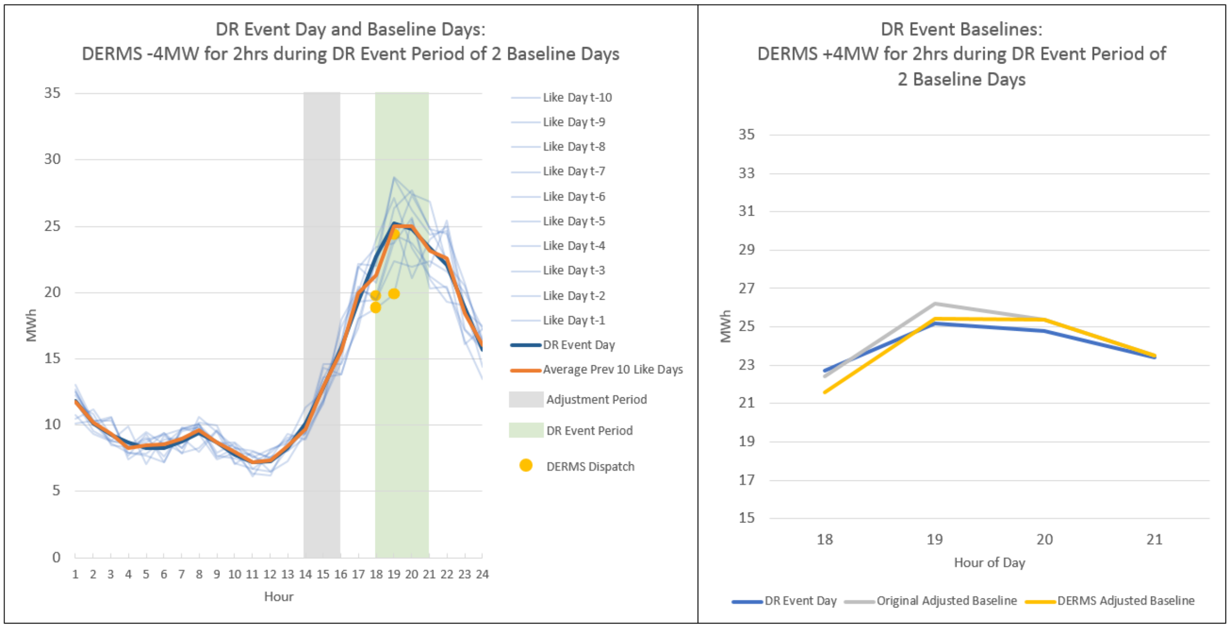

Figure 72: DERMS Dispatch Lowers Adjusted Baseline by Lowering Load during the DR Event Period on Historical Like Days

Raising the Adjusted Baseline:

Similarly, there are three potential DERMS (or other non-CAISO) dispatches that could raise the adjusted baseline:

1. A decrease during the day-of adjustment period time window during any of the 10 “non-DR-event” days used to create the historic baseline (Figure 73)
2. An increase during the adjustment period time window during the DR event day (Figure 74)
3. An increase during the DR event time window during any of the 10 “non-DR-event” days used to create the historic baseline (Figure 75)

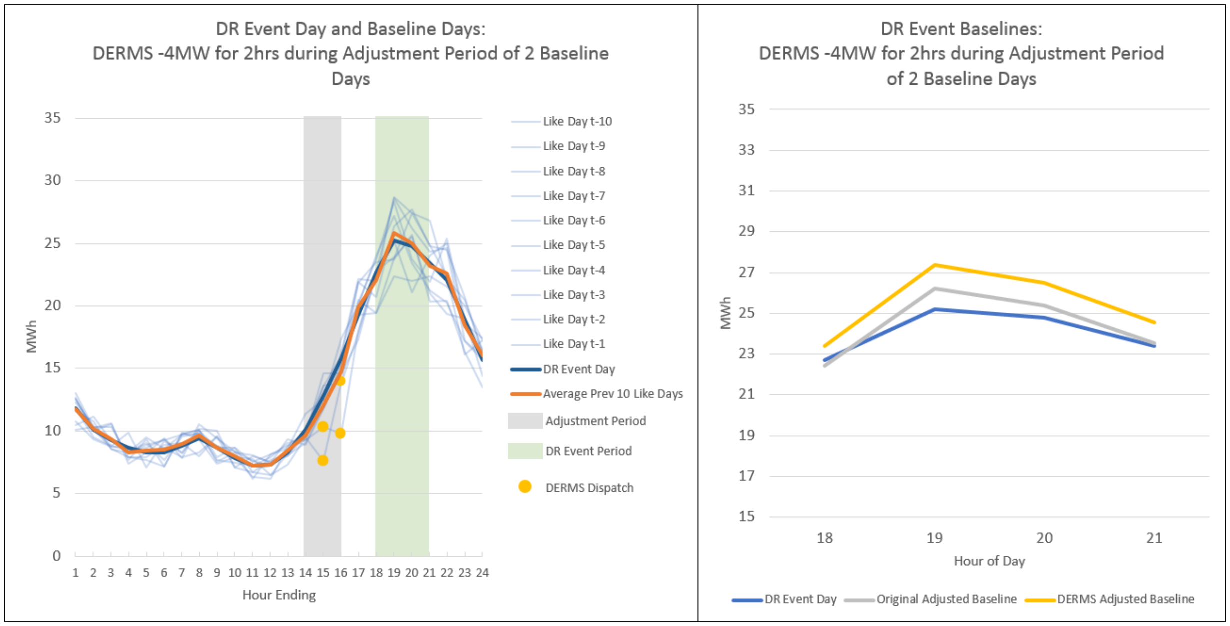

Figure 73: DERMS Dispatch Raises Adjusted Baseline by Lowering Load during the Adjustment Period on Historical Like Days

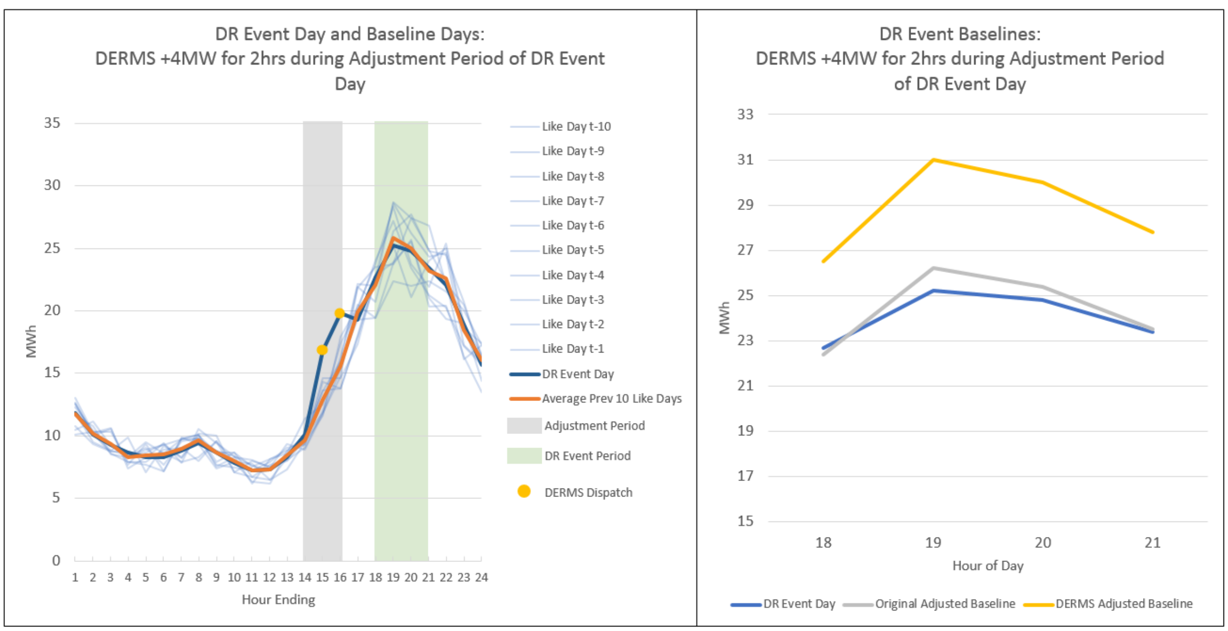

Figure 74: DERMS Dispatch Raises Adjusted Baseline by Raising Load during the Adjustment Period on the DR Event Day

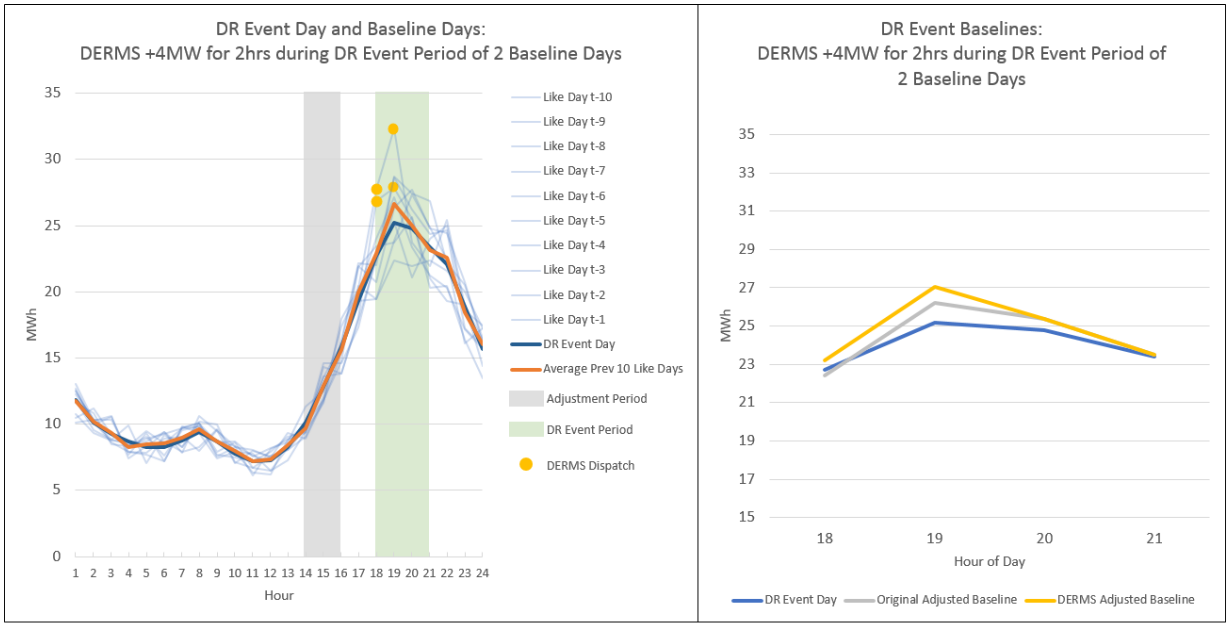

Figure 75: DERMS Dispatch Raises Adjusted Baseline by Raising Load during the DR Event Period on Historical Like Days

24 Appendix L: PG&E DERMS for DG Enablement RFP No. 52150 (August 7, 2015), Supplemental Questionnaire (September 30, 2015), and Onsite Demo Agenda (October 15, 2015). Abridged for EPIC 2.02 DERMS Report.

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