CALIFORNIA ENERGY COMMISSION

CALIFORNIA NATURAL RESOURCES AGENCY

ENERGY RESEARCH AND DEVELOPMENT DIVISION

FINAL PROJECT REPORT

Valencia Gardens Energy Storage Front-of-Meter Interconnection

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PREPARED BY:
Greg Thomson
Wendy Boyle
Craig Lewis
Clean Coalition
Primary Authors

Mike Gravely
Project Manager
California Energy Commission

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- Pathion and Qcells staff members, who provided the technical expertise to develop the appropriate FOM energy storage design for this project.
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- Members of the Technical Advisory Committee, for their expertise and valuable feedback with design changes, their participation in strategic discussions on how to streamline the interconnection process, and their input into key product deliverables content such as the case study.
- The Clean Coalition staff members who worked tirelessly on this project to advance it as far as possible under grant award EPC-16-073.

PREFACE

The California Energy Commission's (CEC) Energy Research and Development Division supports energy research and development programs to spur innovation in energy efficiency, renewable energy and advanced clean generation, energy-related environmental protection, energy transmission, and distribution and transportation.

In 2012, the Electric Program Investment Charge (EPIC) was established by the California Public Utilities Commission to fund public investments in research to create and advance new energy solutions, foster regional innovation, and bring ideas from the lab to the marketplace. The EPIC Program is funded by California utility customers under the auspices of the California Public Utilities Commission. The CEC and the state's three largest investor-owned utilities — Pacific Gas and Electric Company, San Diego Gas and Electric Company, and Southern California Edison Company—were selected to administer the EPIC funds and advance novel technologies, tools, and strategies that provide benefits to their electric ratepayers.

The CEC is committed to ensuring public participation in its research and development programs that promote greater reliability, lower costs, and increase safety for the California electric ratepayer and include:

- Providing societal benefits.
- Reducing greenhouse gas emission in the electricity sector at the lowest possible cost.
- Supporting California's loading order to meet energy needs first with energy efficiency and demand response, next with renewable energy (distributed generation and utility scale), and finally with clean, conventional electricity supply.
- Supporting low-emission vehicles and transportation.
- Providing economic development.
- Using ratepayer funds efficiently.

For more information about the Energy Research and Development Division, please visit the CEC's research website (www.energy.ca.gov/research/) or contact the Energy Research and Development Division at ERDD@energy.ca.gov.

ABSTRACT

In 2017, the California Energy Commission awarded a grant for the Valencia Gardens Energy Storage project to demonstrate the power of local energy storage alongside rooftop solar. The project was implemented at the Valencia Gardens apartment complex, located within San Francisco’s Mission District and home to low-income and elderly residents, and it was intended to be an example of resilient clean energy.

The Valencia Gardens Energy Storage project aimed to:

- **Boost solar penetration:** By storing excess solar energy, and thus allowing for more solar panels on the local grid, which would benefit both Valencia Gardens and California's decarbonization goals.
- **Increase hosting capacity:** Increasing the existing solar photovoltaic hosting capacity of the distribution circuit by at least 25 percent.
- **Enhance grid stability:** By optimizing energy flow, smoothing out demand, and potentially offering services to the California Independent System Operator.
- **Strengthen local resilience:** Providing residents with critical backup power during outages, while avoiding exorbitant costs for grid upgrades.

Despite early progress, including a downsized battery system to mitigate projected cost increases, the Valencia Gardens Energy Storage project encountered significant roadblocks:

- **Interconnection delays:** A two-year lag from the utility stalled project momentum.
- **Costly surprises:** Piecemeal upgrades demanded by the utility inflated project costs.
- **Uncertainties and changes:** Equipment changes and fire code revisions added further hurdles.
- **Permitting roadblocks:** Despite efforts to renegotiate and streamline, fire code restrictions forced the project's termination.

As a result of the project’s termination, the Clean Coalition proposes a statewide approach: deploying front-of-meter solar and storage as a holistic grid design, with streamlined interconnection processes. This could achieve all the benefits initially envisioned for the Valencia Gardens Energy Storage project, paving the way for a cost-effective, secure, and resilient clean energy future for all Californians. Full details of the projects’ goals and objectives, project benefits, and challenges and barriers, including recommendations, can be found in this final report.

Keywords: front-of-meter, behind-the-meter, solar photovoltaic, battery storage, Clean Coalition, holistic grid design, resilient clean energy, streamlined interconnection process, low-income apartments, elderly apartments, distributed energy resources

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Executive Summary

California's clean energy policies are driving the state's advancement towards a future that is predominantly powered by clean electricity. Electrifying segments of energy use while decarbonizing the electric supply will require consistent and rapid deployment of clean energy resources, including distributed energy resources (DERs) like rooftop solar paired with battery storage.[1] Residential renewable energy deployments on the distribution grid are often deployed "one rooftop at a time," without considering a local area's energy requirements and without integrating all the components required to scale the deployments. More robust distributed energy planning and component integration would encourage widespread use of DERs, which can create a more clean, affordable, and resilient electrical system.[2]

In 2017, the California Energy Commission (CEC) made a grant award, Agreement Number EPC-16-309, to the Clean Coalition for the Valencia Gardens Energy Storage (VGES) project. The project proposed installing energy storage enclosures at the 260-unit Valencia Gardens apartment complex, home to low-income and elderly residents, to store existing photovoltaic capacity and to discharge when needed for grid stability, allowing for increased photovoltaic capacity in this circuit. The VGES project aimed to:

- **Boost solar penetration:** By storing excess solar energy, and thus allowing for more solar panels on the local grid, which would benefit both Valencia Gardens and California's decarbonization goals.
- **Increase hosting capacity:** Increase the existing solar photovoltaic hosting capacity of the distribution circuit by at least 25 percent.
- **Enhance grid stability:** By optimizing; energy flow, smoothing out demand and potentially offering services to the California Independent System Operator (ISO).
- **Strengthen local resilience:** Providing residents with critical backup power during outages, while avoiding exorbitant costs for grid upgrades.
- **Demonstrate that front-of-meter (FOM) interconnection can deliver significant benefits to target grid areas:** Behind-the-meter (BTM) refers to DERs that are interconnected on the customer side of the meter, while FOM refers to DERs that are interconnected on the utility side of any customer meter. Importantly, FOM interconnections are not limited by site loads, as are BTM interconnections, so the former can deliver significant benefits to target grid areas rather than just individual facilities that are served by BTM DERs.

The VGES project sought to expand the capabilities of an existing solar energy project in San Francisco by installing two energy storage enclosures to store existing photovoltaic -generated energy to discharge when needed for grid stabilization and to allow for increased photovoltaic

[1] CEC (California Energy Commission). 2024. *2023 Integrated Energy Policy Report*. Available at https://www.energy.ca.gov/publications/2023/2023-integrated-energy-policy-report

[2] Clean Coalition. 2017. *Fact Sheet: Valencia Gardens Energy Storage*. September. Available at https://clean-coalition.org/wp-content/uploads/2019/09/VGES-Task-11.2_Final-Initial-Fact-Sheet-08_wb-25-Jun-2019.pdf

capacity on the circuit. However, the project experienced challenges and barriers that impacted its completion:

- **Interconnection delays:** Regulatory hurdles stalled progress for two crucial years.
- **Soaring costs:** Unexpected utility upgrades inflated the project budget.
- **Shifting requirements:** Equipment changes and fire code revisions added complexity.
- **Permitting roadblocks:** San Francisco's fire department restrictions proved insurmountable, ultimately resulting in the project's termination.

Despite efforts to adapt and renegotiate, the VGES project succumbed to these challenges. Using lessons learned post-project, the Clean Coalition now advocates for a statewide approach: deploying solar and storage strategically across the electric grid, with streamlined processes to unlock the benefits VGES sought. This statewide approach seeks to advance DERs that support a California electric grid dominated by clean and resilient energy sources.

Background

As recognized by the CEC, DERs can help accomplish multiple important energy goals for California, including cost-effective peak management, reduced ratepayer costs, full decarbonization and electrification, and critical community resilience. The barrier to these important DER benefits is that California's current electric grid planning and interconnection framework do not accurately value deployment of FOM DER technologies, preventing their proven benefits from being applied at scale to the state's electric grid.

California communities contain significant potential to generate substantial amounts of solar energy using existing large roofs, parking lots, and brownfield spaces. This locally generated solar potential, combined with energy storage, can be designed and then applied as FOM DER solutions that provide critical benefits to both grid operators and ratepayers. These benefits include reducing the need for expensive long-distance grid infrastructure and peaker plants (peak demand power plants) — thus lowering ratepayer costs and reducing stress on the grid — while providing much-needed energy resilience within communities and increased support for decarbonization across the entire grid.

As California continues its efforts to electrify homes and transportation, by optimally deploying FOM DER across substation areas as a system-wide design that complements both BTM DER and utility scale deployments, California can achieve critical grid efficiencies; these efficiencies would reduce costs for all ratepayers, securely support decarbonization, provide resilience for communities, and achieve equity, since FOM solutions apply to all ratepayers, not just to properties where BTM solutions are located.

Project Purpose and Approach

The VGES project was designed to demonstrate how targeted deployment of FOM energy storage can increase the electric grid's ability to handle greater amounts of distributed solar, yielding substantial grid and ratepayer benefits, and setting the stage for California to bring more distributed solar online.

As part of this project, the Clean Coalition investigated best practices for interconnection of commercial-scale solar and FOM energy storage. The project goals and benefits included, but were not limited to, the following:

- **Hosting capacity:** Enhance the hosting capacity of an existing feeder by more than 25 percent, ensuring that more solar can be deployed.
- **Merchant storage:** Demonstrate the first FOM merchant energy storage project in the California market, reducing costs to ratepayers without ratepayer/utility capital investment or contract liability.
- **Grid services benefits:** Quantify the ability to provide services at the Pacific Gas and Electric Company (PG&E) distribution and the California ISO system levels.
- **Regulatory advancement/policy benefits:** Streamline interconnection for energy storage while demonstrating the energy storage value in hosting capacity, distribution investment deferral/grid needs assessment mitigation, and grid services.
- **Resilience:** Provide energy resilience during grid outages.
- **Utility business model:** Identify and quantify distribution-level utility customer services enabled by FOM energy storage.

Key Results

Ratepayer and Economic Benefits

The VGES project was initially planned to deploy two battery energy storage systems, referred to as the "2-BESS" configuration and totaling 500 kilowatts (kW) and 1096 kilowatt-hours (kWh). The VGES project was intended to showcase FOM energy storage that delivers multiple important benefits, including increased capacity for renewables, improved grid operations, and revenue earnings— in this case, projected at over $40 million per year — along with over $130 million in system-wide annual savings at year 20; this includes peak capacity savings, transmission and distribution lines loss savings, new transmission capacity savings, and energy cost savings. Environmental benefits of the VGES project as designed include carbon dioxide and nitrogen oxide reductions, as well as water use savings. For details, see Appendix A, VGES Economics Forecast and Quantified Benefits. Note that the value benefits also include providing local energy resilience, which is not quantified but is valuable.

Results and Challenges

Despite the significant benefits and progress made on the project during the planning phases that substantiated the benefits, including the submission of an extensive Case Study on FOM energy storage interconnection to the CEC and the California Public Utilities Commission

(CPUC), the VGES project experienced substantial delays and cost challenges. Ultimately, the following policy, interconnection, and permitting barriers prevented the project's deployment:

- **Interconnection Application Process**: It took **two years** from the inception of the Fast Track Interconnection process to complete the pre-construction phase, when permits could be pulled, as opposed to the utility's expected six-month process. The delays were due to mandatory public safety power shutoff events, wildfires, a lack of resources, PG&E personnel changes, and the COVID pandemic.
- **Interconnection Costs**:
  - During the interconnection review process, the estimated project cost increased from the expected **$156,999** to **$460,887,** due to unanticipated upgrade requirements that were conveyed by the utility via a series of piecemeal notices; of this increased amount, $173,763 was actually paid before the VGES project was permanently stalled. See Figure 6 and Figure 8 for cost details.
    - In January 2020, PG&E recommended downsizing the battery energy storage system from 2-BESS to 1-BESS. However, this was not an option at the time because it did not comply with the CEC's grant requirements of participation in the California ISO market, which at the time required a minimum 500 kW resource capacity.
    - On 15 July 2020, the Federal Energy Regulatory Commission (FERC) approved FERC 841, allowing the California ISO to reduce its minimum 500 kW resource capacity to 100 kW. The project team immediately implemented the recommendation to reduce the VGES system size from a 2-BESS of 500 kW and 1096 kWh to a 1-BESS of 250 kW and 556 kWh.
  - Despite this BESS downsizing, the projected project costs did not decrease substantially, because the utility still required a recloser (a switch that automatically shuts off power when trouble occurs) and a secondary transformer in the public right-away (installed in an underground vault). This meant that the majority of the interconnection cost increases required for the 2-BESS configuration would still apply to the 1-BESS configuration.
- **Permitting**:
  - In an effort to resolve permitting issues, multiple meetings were held with the utility and the City and County of San Francisco, and a former fire marshal indicated that the location of the energy storage was not an issue. (Permitting Office in-person visits were conducted in February 2018 and October 2019; pre-construction onsite meetings that included PG&E were conducted in March, July, and December 2019.) However, the new fire marshal refused to provide the approvals that would be required for even the 1-BESS configuration. It is important to note that Mike Gravely, CEC project manager and the originally assigned CEC contract agreement manager, attended at least one of the pre-construction meetings.

- The city's Planning Department did not disclose until January 2020 that the Valencia Gardens apartment complex was under a Planned Unit Development that required a conditional use authorization to amend the existing Planned Unit Development to approve the installation of any additional structures within the 100 square-foot threshold; the VGES 2-BESS footprint exceeded this allowable threshold.
- In October 2020, the conditional use authorization was submitted, and the city's Planning Commission voted to approve the 1-BESS 250 kW/556 kWh design and the proposed solution, which included building a concrete firewall between the BESS and other structures (which was a solution similar to that approved for the Redwood Coast Airport Microgrid).
- Despite approval from the city Planning Commission and despite letters from other fire department districts, the International Association of Fire Chiefs, the International Association of Fire Fighters, and the National Association of State Fire Marshals supporting the exception approval of UL9540A, the city's new fire marshal would approve only the base California Fire Code; he would not approve the proposed solution of building a concrete firewall.
- See Appendix E for details.

Despite the exhaustive efforts to deploy VGES, the project ultimately failed to proceed to deployment. The exhaustive efforts included massive unforeseen interconnection costs, changing of the energy storage subcontractor, the halving of the project to a 1-BESS configuration, CEC approval on three budget amendments and two no-cost term extensions, and the requirement for any BESS below 500 kW to undergo a costly scheduling coordinator to interface with the California ISO, which added significant operational costs. See Appendix A for details.

Ultimately, the fire code permitting restrictions prevented project deployment and resulted in the mutual termination of the grant award, Agreement Number EPC-16-073.

Knowledge Transfer and Next Steps

A critical factor to consider with any FOM project is that it is vital to engage, at an early stage, with decision-making personnel from the utilities and the local jurisdiction, including the fire department. Early coordination can help to identify and potentially mitigate any potential pitfalls or roadblocks that may result in schedule delays; cost increases due to equipment upgrades, resulting in design changes; or interconnection and/or permitting restrictions that may prohibit project deployment. Another important factor to consider is to ensure that the project partners, including the project's Technical Advisory Committee, are actively engaged throughout the entire project. Even though the Clean Coalition was diligently engaged with the utilities, the San Francisco Planning Department, the San Francisco Fire Department, and the Technical Advisory Committee, the VGES project was still unable to be deployed under this CEC grant award due to permitting restrictions cited by the city fire marshal.

Although the VGES project was not deployed, based on lessons learned during the wholesale distribution access tariff interconnection process, the Clean Coalition developed and submitted an extensive Case Study on FOM energy storage interconnection to the CEC in 2021 as part of the VGES project. In 2022, the Clean Coalition shared the case study with the CPUC through multiple proceedings, highlighting the barriers encountered with the project to date as well as the proposed solutions. The Case Study accompanied the Clean Coalition's December 2021 newsletter and was featured in the following media publications:

- **Clean Coalition:** "FOM energy storage interconnection needs serious policy innovation"; https://clean-coalition.org/news/front-of-meter-energy-storage-interconnection-case-study/
- **Energy Central:** "FOM energy storage Interconnection Case Study"; https://energycentral.com/c/gr/front-meter-fom-energy-storage-interconnection-case-study
- **Bay Area Monitor:** "Keeping The Lights On With Microgrids"; https://bayareamonitor.org/article/keeping-the-lights-on-with-microgrids/

The Clean Coalition submitted pertinent VGES information in CEC, CPUC, and California ISO proceedings, as follows:

- **CEC:** Docket 23-SB-100 (FOM), Docket 23-IEPR-01, Docket 21-ESR-01, Docket 22-RENEW-01-1, and Docket 22-OII-01
- **CPUC:** R. 19-09-009 (Microgrids), R. 20-11-003 (Emergency Reliability), and DER Action Plan 2.0
- **California ISO**: Aggregate Capabilities Constraint Initiative

A list of all of the Clean Coalition's regulatory filings can be found at https://clean-coalition.org/regulatory-filings/.

Proposed Solution and Next Steps

To achieve successful FOM DER deployment, enhancements are required in the FOM interconnection process. These include energy storage permitting exceptions as allowed by UL9540A to achieve higher levels of accountability, transparency, communication, and consistency regarding timelines, costing, and design, so that these important FOM projects can be planned appropriately and then deployed with known costs and in a timely manner.

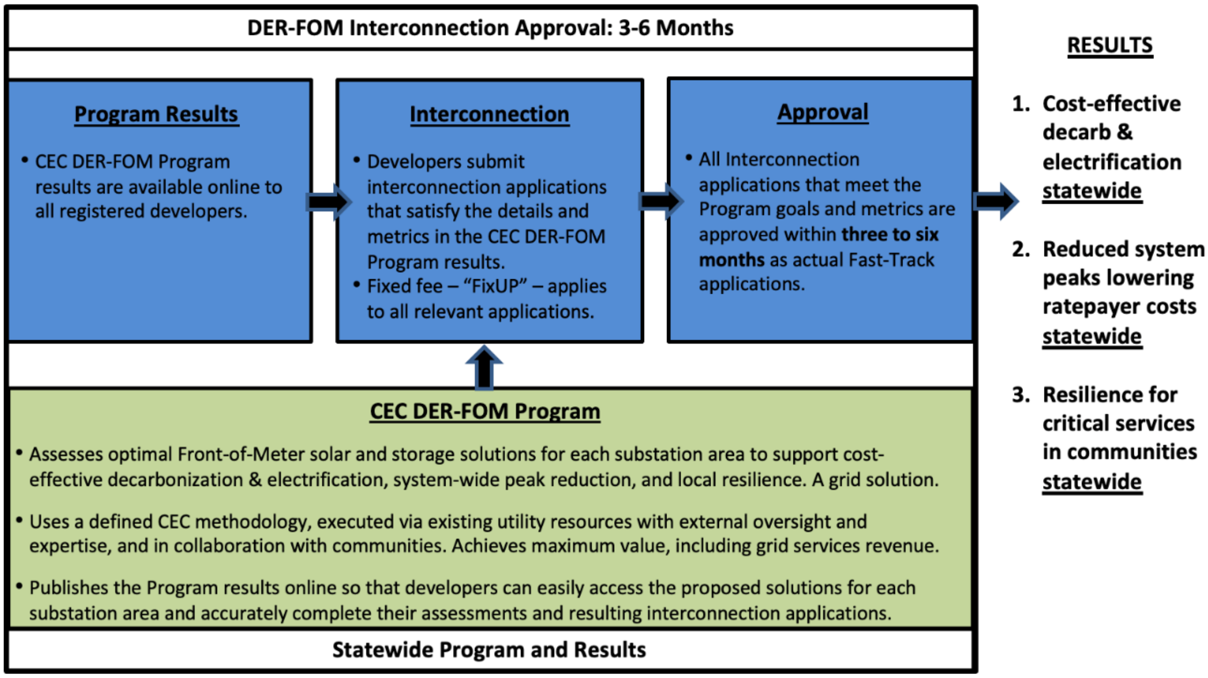
The Clean Coalition's mission is to accelerate the transition to renewable energy and a modern grid through technical, policy, and project development expertise — which requires installation of significant amounts of DERs throughout California and aligns with the CEC's and the state's renewable energy goals. To achieve this goal, the project team recommended the following solutions and next steps:

- Proposed solution: A statewide program that analyzes and designs optimal FOM distributed energy storage and solar as a system-wide feature for the California grid, complementing both BTM DER and utility-scale deployments. (See the proposed solution diagram in Figure 1.) This will deliver the intended VGES project benefits as a statewide solution, utilizing FOM storage and solar to provide these multiple benefits: (1) cost-effective and secure support for full decarbonization and electrification, (2) improved grid operations with reduced systemwide peaks and thus lower ratepayer costs, and (3) critical resilience for all California communities. Combined with this system-wide program, an accurately streamlined fast-track interconnection process for FOM projects would achieve higher levels of accountability, transparency, communication, and consistency regarding timelines, costing, and design, enabling developers to deploy these systems in a timely and cost-effective manner.

- Policy innovation: A fixed fee and utility pays policy — FixUP — that extends the existing BTM streamlined interconnection processes, timing, and price certainty to small FOM projects. FixUP would allow FOM projects to determine whether they qualify for fixed-fee interconnection, based on publicly accessible eligibility criteria. Importantly, FixUP would treat small FOM projects in a similar manner as BTM projects of up to 1 megawatt. And utilities would directly pay for interconnection costs since the benefits apply broadly. In addition, multiple existing policies should apply directly to streamlining FOM interconnection. The Conclusions section of this report provides further detail.
- CEC-driven streamlined FOM interconnection pilot program: A pilot to fully streamline the FOM interconnection, working in concert with a program that applies FOM solar and energy storage as a statewide solution, including virtual power plants. Combined with FixUP, this formal California "DER FOM' Program" would be implemented using a CEC-approved methodology across substation areas to achieve these critical energy goals:
    1. **Peak Reduction:** Reduce peaks and thus reduce ratepayer costs for long-distance grid infrastructure.
    2. **Decarbonization Support:** Enable distributed solar to be deployed in a cost-effective manner to support full decarbonization and electrification.
    3. **Resilience:** Provide much-needed energy resilience for critical services in communities, including all disadvantaged communities.

Figure ES-1 summarizes this proposed statewide solution, achieving the critical results as stated, with more details provided in the Conclusions section of this report.

Figure ES-1: Proposed DER-FOM Program



In addition to the above recommended solutions, the following solutions should be considered:

- Jurisdictions and fire departments should allow flexibility, so that densely populated areas receive exceptions as allowed by UL9540A, including the construction of a concrete firewall between the BESS and other structures. See Appendix E for details.
- Accurate and current integration capacity analysis data must always be available, since it allows developers to determine locations where grid upgrades are not necessary and/or which upgrades are the most cost-effective.

All of the above enhancements would fully apply the multiple key values of FOM DER technologies to the California electric grid.

CHAPTER 1: Introduction

The Valencia Gardens Energy Storage (VGES) project was designed to demonstrate energy storage as a front-of-meter (FOM) distributed solution that can apply across the electric grid to 1) increase support for renewable energy, 2) improve grid operations by reducing peaks and thus lowering system-wide grid infrastructure costs, and 3) provide critical local energy resilience. The project's design provided a replicable model for California that encompasses energy storage technology and features, interoperability with grid operations, and multiple beneficial-use cases that are supported across the state's electric grid system. In addition, this project recommended advancements in policy, interconnection, and market mechanisms in support of the full value of these FOM energy storage deployments. The VGES project would utilize strategic FOM distributed energy resources (DERs) to help California reach the scale and cost-effectiveness needed to achieve the state's clean energy, grid operation, and resilience goals. In addition, the project was located in an urban area in the Mission Dolores neighborhood of San Francisco, benefitting a disadvantaged area of the city while showcasing how distributed energy storage can be configured to work in urban settings.

The primary goal of the VGES project was to achieve specific technological advancements, utilizing FOM energy storage on a circuit in the distribution grid, that enabled California to achieve its statutory energy goals. The project was designed to demonstrate achievements that can apply across the California grid, including:

1. The use of FOM energy storage as an automated and integrated energy storage system on a circuit, to enable better electricity balancing on the circuit, increase solar photovoltaic (PV) hosting capacity on the circuit, and provide the California ISO with ancillary services. This solution would interoperate with California ISO dispatch services while providing indefinite renewables-based backup power as an energy-resilience solution for the community.
2. A local energy system controller with an open architecture capable of using any combination of batteries, renewable generation, inverters, and generators.
3. A replicable energy storage system size and container configuration that meets market needs by being readily applicable to higher-density urban areas (specifically, a product for high-density/large-load pocket areas). This enables faster market adoption by providing energy storage in smaller containers that can be installed in multiple locations on a single site, or on multiple sites along a feeder, all integrated and optimized as a single system for utilities and independent systems operators.
4. An energy storage system that delivers the complete list of grid services efficiently and simultaneously, including demand response/demand charge reduction, time of day optimization/arbitrage, solar PV firming, frequency regulation, backup power, ramping support, volt-amp reactive control, and black start.

5. A solution that investigates and expects to evolve distribution-transmission interoperability via automated control signals and responses for successful operation of energy storage systems capacity for California ISO ancillary services.

The key benefits of this important VGES project included:

- **Hosting capacity:** Enhancing the hosting capacity of an existing feeder by more than 25 percent, ensuring that more solar can be deployed.
- **Merchant storage:** Demonstrating the first FOM merchant energy storage project in the California market, reducing costs to ratepayers without ratepayer/utility capital investment or contract liability.
- **Grid services benefits:** Quantifying the ability to provide services at the Pacific Gas and Electric (PG&E) distribution and California ISO system levels.
- **Regulatory advancement/policy benefits:** Streamlining interconnection for energy storage while demonstrating energy storage value in hosting capacity, distribution investment deferral/grid needs assessment mitigation, and grid services.
- **Resilience:** Providing energy resilience during grid outages.
- **Utility business model:** Identifying and quantifying distribution-level utility customer services enabled by FOM energy storage.

The Clean Coalition is a nonprofit organization whose mission is to accelerate the transition to renewable energy and a modern grid through technical, policy, and project development expertise. The Clean Coalition drives policy innovation to remove barriers to procurement and interconnection of DERs such as local renewables, energy storage, and demand response. The organization establishes programs and market mechanisms that realize the full potential of integrating these solutions It is active in numerous proceedings before state and federal agencies throughout the United States, and it collaborates with utilities (and other load-serving entities) and municipalities (and other jurisdictions) to create near-term deployment opportunities that prove the technical and economic viability of local renewables, distributed energy storage, and other DERs.

CHAPTER 2: Project Approach

The VGES project was staged to become the first FOM merchant energy storage system without utility offtake in California. This groundbreaking project, located at the Valencia Gardens apartment complex, which houses hundreds of low-income families and senior citizens in the Mission Dolores neighborhood of San Francisco, was intended to showcase how FOM energy storage can be effectively deployed in dense, developed urban environments. The VGES project was originally planned to deploy a 2-BESS 500 kW/1096 kWh. Under FERC 841 (approved on July 15, 2020), the project was able to be modified to deploy a 1-BESS 250 kW/556 kWh, which helped mitigate some of the unexpected projected cost increases. The 2-BESS and the 1-BESS were strategically designed to provide a replicable model for providing grid benefits exactly where they are most needed.

The VGES project was designed to increase the solar hosting capacity of the distribution feeder by at least 25 percent, allowing more solar to be sited along the feeder. Valencia Gardens apartment complex was previously sited with existing solar of 516 kWdc (total installed system cost per kilowatt of direct current capacity) on a feeder with a total solar capacity of 580 kW, which exceeded the feeder peak load of 570 kW. The VGES project included quantifying the technical and economic benefits of deploying energy storage on distribution feeders that are nearing capacity for hosting solar — local energy storage was added to time-shift solar to increase the local feeder capacity for solar while simultaneously optimizing grid operations and ratepayer economics. In addition, the energy storage being deployed FOM, in combination with the existing solar, provided cost benefits in reducing the load on the transmission system during peak times while providing indefinite resilience to critical loads on the feeder during all grid outages. This solution was designed to be replicable on all feeders, to provide the benefits of scaling clean energy for the California grid while providing cost benefits to all ratepayers and much-needed resilience to communities.

The key features of the VGES project included:

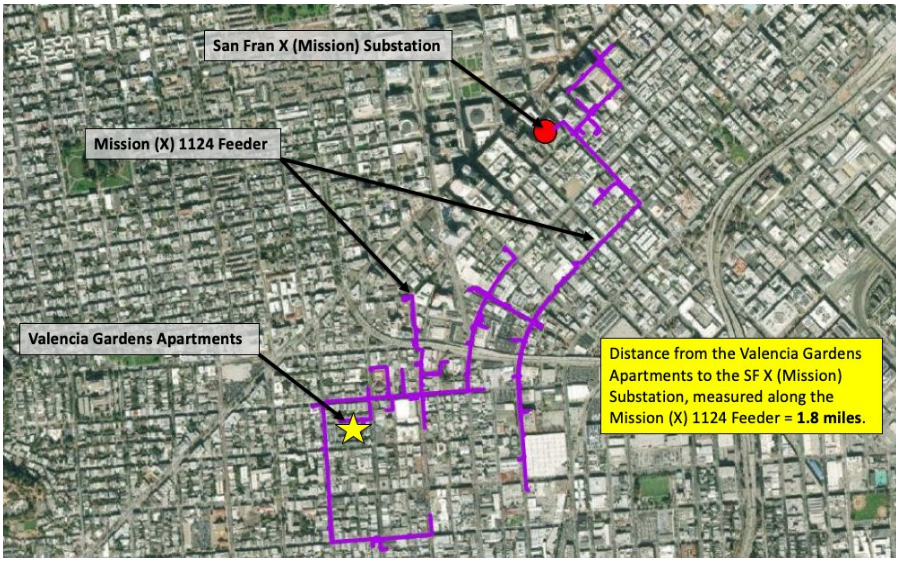
- Creation of the first FOM merchant energy storage project in California.
- Deployment of energy storage that provided a replicable model for grid benefits exactly where they are needed most.
- Sited at Valencia Gardens, a 300,000 square-foot disadvantaged and senior housing facility with 260 units in San Francisco’s Mission District.
- A design that would increase the solar hosting capacity of the distribution feeder by at least 25 percent. The Valencia Gardens apartment complex has existing solar of 516 kWdc, on a feeder with a total of 580 kW of solar, exceeding the feeder peak load of 570 kW.
- An examination of how energy storage can be monetized by California ISO wholesale markets.

- A provision for indefinite renewables-driven backup power to critical loads at Valencia Gardens and potentially other facilities served by the feeder.

Project Feeder Maps

Figure 1 shows the project site, on the Mission 1124 Feeder from the San Fran X (Mission) Substation.

Figure 1: VGES Mission 1124 Feeder Map



Source: PG&E ICA maps

Figure 2 shows the substation feeder lines, colored according to their available capacity for adding solar. Green indicates more available capacity for adding solar onto the feeder, and red indicates a higher probability of needing feeder upgrades for adding solar projects.

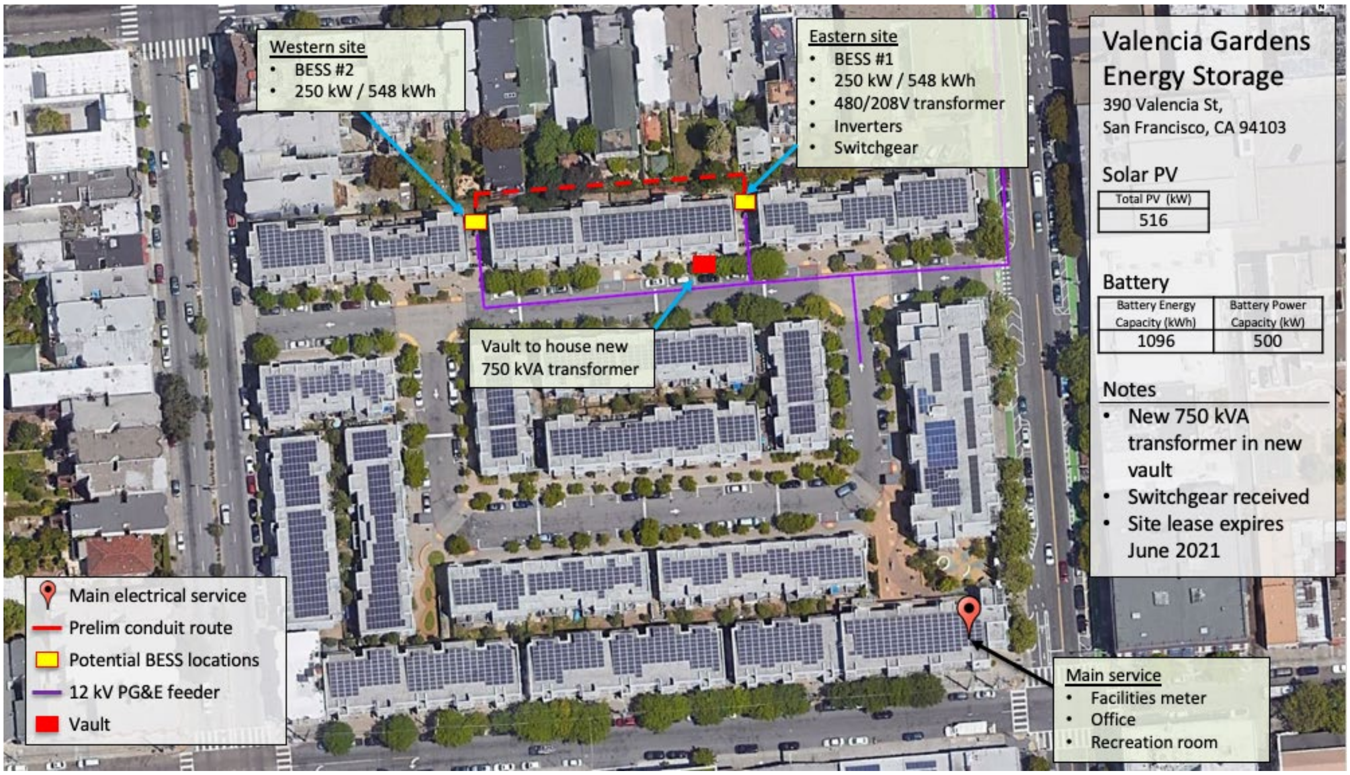
Figure 2: VGES Mission 1124 Feeder Map

Source: PG&E ICA maps

Project Site Overview

Figure 3 shows the locations of the originally planned 2-BESS 500 kW/1096 kWh project (yellow squares), each at capacities of 250 kW/548 kWh. The VGES project had a total capacity of 500 kW/1096 kWh. The peak load on the circuit was 570 kW, and the solar capacity on the circuit was 580 kW. The dashed red line indicates the DC conduit connecting the two systems. The existing 516 kW of solar can be seen scattered among the various housing-project rooftops. The 12-kilovolt (kV) circuit feeder for the property is shown in purple.

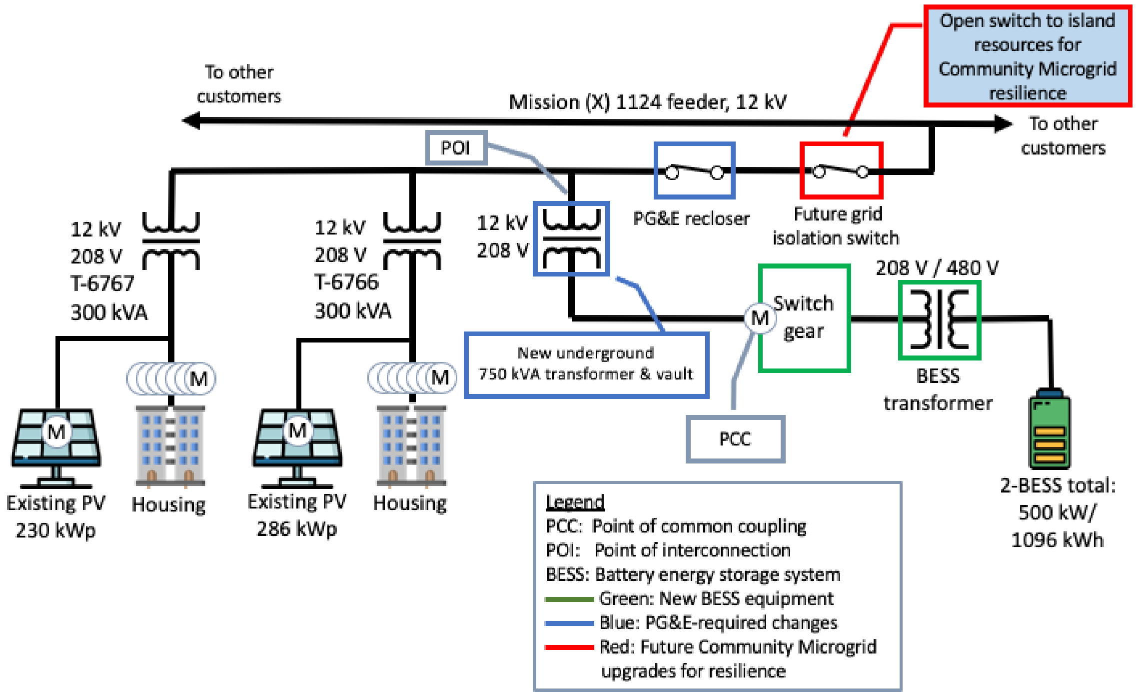
Figure 3: VGES Project Site Location



Source: Google Earth

Figure 4 shows the future resilience opportunity at the Valencia Gardens apartment complex, by adding a grid isolation switch that could be activated in the event of a grid outage and using the solar plus storage to maintain electrical power for the residents and the office. Energy storage for the VGES project was sized for community microgrid operations that can provide indefinite solar-driven backup power to the most critical loads during grid outages of any duration. Additionally, PG&E’s Community Microgrid Enablement Tariff would have been a potential fit for a potential community microgrid follow-on phase.

Figure 4: VGES Resiliency Configuration



kVA = kilovolt-ampere; kWp = kilowatt peak; POI = point of interconnection

Project Partners, Advisors, and Other Participants

The primary project partner was originally energy storage subcontractor Pathion, but it was changed to Qcells (QC) after Pathion was unable to absorb the utility's unexpected interconnection cost increases. The other participants were Mission Housing (site host), PG&E, the California ISO, the San Francisco Planning Department, and the San Francisco Fire Department.

CHAPTER 3: Results

Economic and Operational Potential

The VGES project provided key lessons regarding the important benefits of FOM energy storage: increasing capacity for renewables, improving grid operations, and earning revenues — in this case projected at over $40 million per year — along with over $130 million in system-wide annual savings at year 20; this includes peak capacity savings, transmission and distribution (T&D) lines loss savings, new transmission capacity savings, and energy cost savings. Environmental benefits included reductions of carbon dioxide (CO_2) and nitrogen oxides (NOx), plus water savings. (See Appendix A, VGES Economics Forecast and Quantified Benefits, for details.) The value benefits include providing local energy resilience, not quantified but certainly valuable. Unfortunately, the barriers to deploying this solution prevented these benefits from being proven in actual operation.

Expected timing: According to PG&E, the Fast Track Interconnection study process typically takes about three months and consists of 10 screens. If the Fast Track screens determine that a project does not meet the process requirements, an additional independent or cluster study is required before the project can interconnect.

Reality: The FOM Interconnection Application submission for VGES was successfully transmitted to PG&E on December 3, 2017. After that date, the VGES FOM Energy Storage project experienced multiple delays and other challenges. Key among these challenges were the following:

- **Time:** It took **two years** from the inception of the Fast Track Interconnection process to complete the pre-construction phase, when permits could be pulled.
    - **Lengthy interconnection process:** It took two years to complete the Fast Track Interconnection process and move into pre-construction; PG&E had originally indicated that this process would take less than six months. This caused significant delays with the project schedule.
    - **Delays with PG&E engineering estimates and construction drawings:** It then took 12 months from execution of the Small Generator Interconnection Agreement (SGIA) to receive engineering estimates, construction drawings, and a project schedule, which prohibited the project from completing the required permits.
    - **PG&E Interconnection Agreement delays:** PG&E failed to meet some tariff deadlines for interconnection review and issued notices of delay, and the utility took the maximum allowed time at most other opportunities. This impacted the timeline and created major project uncertainty.

- **Lack of PG&E personnel resources:** A lack of personnel availability and changes of key PG&E personnel, including such key roles as the interconnection manager and service planner, also significantly slowed project progress.
- **No room for equipment lead times:** The delays during the interconnection agreement process and the pre-construction phase made it virtually impossible to maintain a project schedule.

- **Interconnection Costs:** The projected costs for the project increased almost three-fold throughout the process — from the expected **$156,999** to **$460,887**, of which $173,763 was paid before the project was halted.
  - **Cumulative cost increases:** Unexpected cost increases seriously impacted the project's budget, making it difficult for the project to move forward.
  - **Inflexibility with discretionary upgrades:** Given the lengthy interconnection application process and delays, there was insufficient time to find workaround solutions such as a potential recloser solution (for example, an IEEE-certified hardware limiter to guarantee a cap on the total exported power of the feeder).
  - **Last-minute utility construction design changes:** One year after the small generator interconnection agreement (SGIA) was executed, PG&E changed the transformer location and required the installation of an underground vault in the public right-of-way. This increased the project cost by an additional $145,000 after execution of the SGIA and after the second pre-construction site walk.
- **Permitting Issues:** Permitting the energy storage for this site became an issue due to the City and County of San Francisco's permitting restrictions, specifically the following:
  - The San Francisco Planning Department did not disclose until two years after the first pre-construction meeting (held in March 2019) that the Valencia Gardens apartment complex was under a Planned Unit Development (PUD) requiring a conditional use authorization (CUA) to amend the existing PUD to approve installation of any additional structures what must be within the 100-square-foot threshold; the VGES 2-BESS footprint exceeded this allowable threshold. The CUA for a 1-BESS 250 kW/556 kWh solution was submitted and approved by the city Planning Commission on December 15, 2020.
  - Despite the Planning Commission's approval of the 1-BESS 250 kW/556 kWh and the proposed solution of building a concrete firewall between the BESS and other structures, the city's new fire marshal considered the VGES project as an "Installation near exposure." Further, as the City and County of San Francisco considered the VGES site as a densely populated site, the fire marshal would approve only the base California Fire Code and would not provide exception approval for the UL9540A or the proposed concrete firewall. Letters from other fire department districts, the International Association of Fire Chiefs, the International Association of Fire Fighters, and the National Association of State

Fire Marshals supporting approval of UL9540A were provided to the fire marshal but did not make a difference.

- Flexibility should be considered, so that densely populated areas approve exceptions as allowed by UL9540A. See Appendix E for details.

Interconnection Challenges/Barriers

The Fast Track Interconnection process is designed for smaller facilities of up to 5 megawatts (MW) that would have a minimal impact on PG&E's electric system. Project proposals are accepted by PG&E throughout the year on a rolling basis. Figure 5 lists the total capacity, including voltage and location conditions, necessary to qualify for the Fast Track Interconnection process as applied to the VGES project. The VGES project, fed from a 12 kV feeder with a total capacity of 500 kW and located 1.8 miles from the substation, applied to the orange zone as shown in Figure 5.

Figure 5: PG&E Fast Track Interconnection Process

Fast Track line voltage	Fast Track capacity eligibility regardless of location	Fast Track eligibility on a mainline and ≤ 2.5 electrical circuit miles from substation
< 5 kV	≤ 500 kW	≤ 500 kW
≥ 5 kV and < 15 kV	≤ 2 MW	≤ 3 MW
≥ 15 kV and < 30 kV	≤ 3 MW	≤ 4 MW
≥ 30 kV and < 60 kV	≤ 4 MW	≤ 5 MW

Source: PG&E

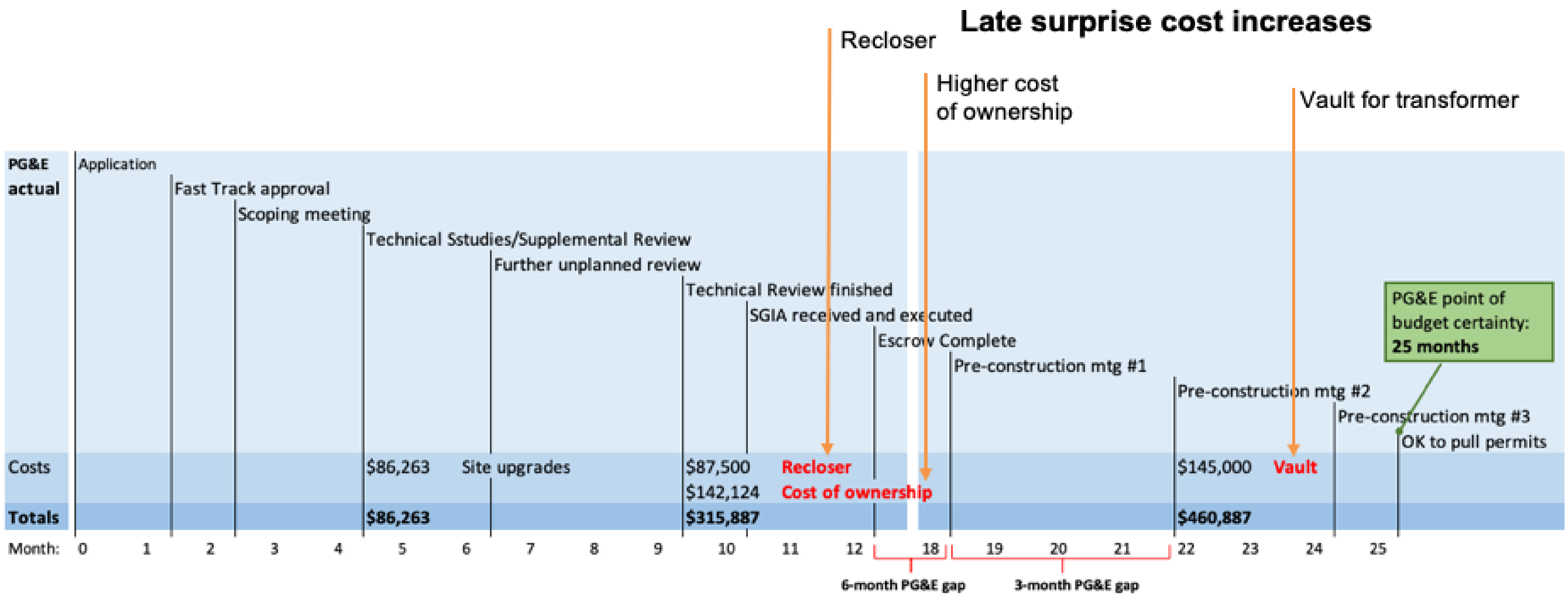
Note that the interconnection customer can determine this information about a proposed interconnection location in advance by requesting a pre-application report pursuant to Section 1.2 of PG&E's Wholesale Distribution Tariff. The items and steps to be completed under the Fast Track Interconnection process include:

- **Application:** Requires a site plan, a single-line diagram (SLD), site control documents, and the application fee.
- **Scoping Meeting:** Held to secure agreement on the point of interconnection and the generator size; PG&E advises if Fast Track approval is granted.
- **Technical Studies/Supplemental Review:** Analyzes the impact of generation on PG&E's electrical system. Shows needed capital improvements to PG&E's electrical system and initial cost estimates to ensure safety and reliability of the grid.

- **Interconnection Agreement:** To be executed.
- **Project Implementation:** Construction planning meetings, refined cost estimates, final engineering drawings.

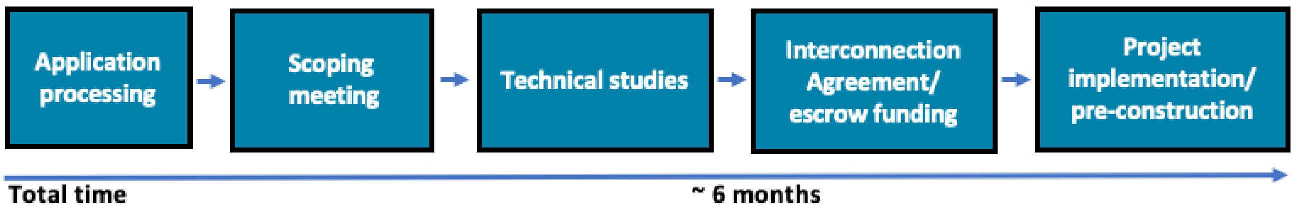
For the VGES project, it was anticipated that the process, from submission of the FOM Interconnection Application to being able to pull permits, would take about six months. Instead, the process took **over two years** (Figure 6).

Figure 6: VGES Interconnection Application Process Timeline



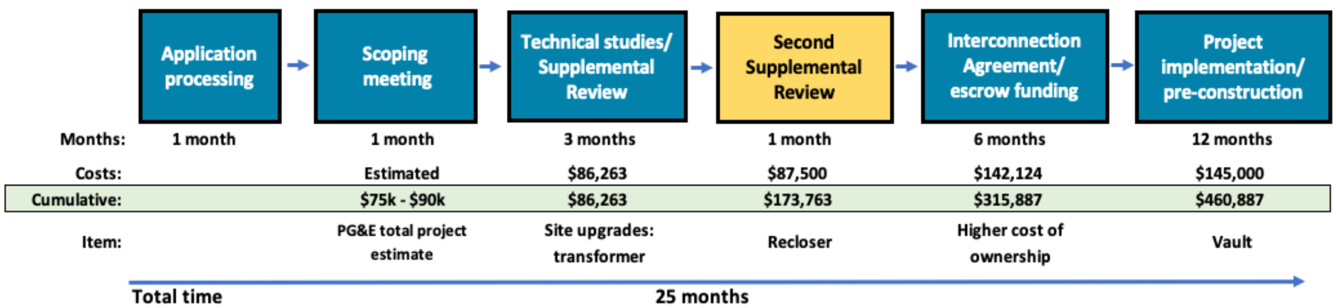
The following graphics compare the expected timeline and costs (Figure 7) to the actual timeline and cost (Figure 8) associated with the process from December 2017 (interconnection agreement application submittal) to December 2019 (permission to pull permits).

Figure 7: Expected VGES Fast Track Interconnection Process Timeline



Expected VGES Fast Track Interconnection process: approximately six months and a final cost in the range of $75,000 to $100,000

Figure 8: Actual VGES Fast Track Interconnection Process Timeline



Actual VGES Fast Track Interconnection process: 25 months and a final cost of nearly $461,000

As an important metric and reference, while working on the Peninsula Advanced Energy Community initiative, the Clean Coalition studied 209 applications for FOM (also known as wholesale distributed generation) Interconnection approval and found that 82 percent failed to secure permits and/or dropped out of the process. The 18 percent of applications that were approved took from six months to 2.25 years for approval. As part of the Peninsula Advanced Energy Community Initiative, the Clean Coalition created a pilot for streamlining interconnection (see https://clean-coalition.org/peninsula-advanced-energy-community/interconnection).

The California utilities indicated they were working to improve the approval timelines, communication, and adherence for FOM interconnection, and that anecdotes by parties might relate to past practices but did not pertain to the current situation. With respect to the upgrade timelines, PG&E noted that it agrees on specific timelines with the customer for each project, and that these timelines are included in interconnection agreements and are discussed and updated with the customer throughout the project life cycle. PG&E indicated that it had been working on service planning improvements for the past several years, and the utility had set up a dedicated centralized work group to handle all generation interconnection requests. However, as stated, the VGES project experienced frequent and major delays due to PG&E's failure to meet timelines, its frequent rescheduling of dates, lengthy and poorly coordinated practices, and the passing of steps from one staff member to another, both within and between various utility departments.

The VGES project resulted in a strong validation that California has a continuing issue that causes barriers to FOM deployments. Developers need certainty that a successful application will lead to a deployed project in a reasonable timeframe, so they can make the up-front investment required to participate in the program. Unfortunately, in the applications studied, most attempts to procure any significant amount of capacity fell short, in large part due to developers losing interest because of the long delays caused by the current interconnection process. All the programs described in the sections below, as well as any program where FOM storage is eligible, would benefit from the streamlined interconnection procedures as proposed in this report.

System Design and Interconnection Reform

As a result of the VGES project, it became apparent that California needs reform for deploying FOM energy storage solutions. An ongoing issue persists regarding whether California has deployed a sufficient resource portfolio to maintain reliable grid operations during peak hours and summer extreme weather events. Regulators approved new and increased procurement targets following both the mid-August 2020 reliability crisis and the record-setting demand in early September 2022, necessitating a historic rate of deployment. California is currently examining the entire procurement process, searching for ways to maximize efficiency and ensure that reliability targets are met on time. This can and should be partially solved by deploying more FOM energy storage and solar as a dedicated grid solution, and specifically as a result of the CEC DER-FOM program as proposed in this report.

Although it was ultimately the permitting restrictions from the San Francisco fire marshal that prohibited the VGES project from moving forward to deployment, one of the key areas identified as preventing FOM deployment is interconnection. On March 11, 2022, CPUC President Alice Reynolds sent a letter to the CEOs of the investor-owned utilities (IOUs), requesting information on interconnection related to possible bottlenecks and resource/staffing needs. Of the three IOUs, only San Diego Gas & Electric (SDG&E) chose to identify the Wholesale Distribution Access Tariff (WDAT) interconnection as an area of concern.[3] None of the IOUs provided WDAT-specific recommendations or considered the potential to handle the exponentially increasing number of applicants seeking FOM WDAT interconnections as grid conditions change (e.g., the state needs to electrify and decarbonize). While interconnection reform is at the center of the conversation on reliability, action is needed on all levels of government to mandate that the IOUs initiate the process for WDAT. For example, on the state level, a CPUC decision would motivate the IOUs to translate the lessons learned from Rule 21 interconnection reform to WDAT, and the CEC's SB 846 analysis and Clean Energy Reliability Investment Plan can provide specific recommendations to streamline the process as laid out in this report.

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[3] SDG&E (San Diego Gas & Electric Company). 2022 (May). SDG&E's Responses to the Commission's March 11, 2022, Letter Concerning the "Prioritization of Interconnection to Ensure Grid Reliability." pp. 6 Available at https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/summer-2021-reliability/tracking-energy-development/ceo-sdge-response-to-cpuc-letter-51222-redacted-version.pdf.

Also, as a testament to the interconnection challenges/barriers at the national level, the United States Department of Energy (U.S. DOE) partnered with research teams from the Pacific Northwest National Laboratory, Lawrence Berkeley National Laboratory, and National Renewable Energy Laboratory to launch a new initiative — the Interconnection Innovation e-Xchange. As confirmed by Becca Jones-Albertus, director of the U.S. DOE's Solar Energy Technologies Office, interconnection represents a major barrier to clean energy resource deployment and is one of the most important issues being worked on within the Solar Energy Technologies Office and the U.S. DOE — and with particular interconnection challenges faced by FOM community solar and energy storage projects, many of which are focused on expanding access to low- and moderate-income people.

Extending Lessons Learned From Rule 21 Interconnection to Streamline WDAT Interconnection and Improving Integration Capacity Analysis Maps

In Decision 20-09-035, the CPUC approved the use of the operational flexibility of the integration capacity analysis (ICA) values in the Rule 21 interconnection process. As explained in the Rule 21 Working Group 4 background on Issue F, "The concept of operational flexibility within the ICA context is that utilities need the flexibility to reconfigure circuits during maintenance or unplanned outages. Because customers sometimes get switched to adjacent circuits, the impact of DER on circuits that they might be connected to must be studied, even if they are not connected to those circuits in normal circumstances."[4] A 2021 report in *Nature Energy* explains that, when taking into account existing operational flexibility (Op-Flex) constraints, 36 percent of PG&E and 40 percent of Southern California Edison (SCE) customers, respectively, will not be able to install rooftop solar without significant grid upgrades. Thus, improving hosting capacity where there are Op-Flex constraints will increase DER access and help address equity issues.[5]

In cases where the output of a DER facility is above the ICA value when Op-Flex constraints are included but lower than the ICA value when the Op-Flex constraints are not considered, an operational alternative may be approved. Projects that interconnect with this option will be allowed to export normally in most grid conditions, except during Op-Flex events, where curtailment may be required. Interconnection via this method, matching a project's limited generation profile to local Op-Flex ICA values, enables areas with low hosting capacity and/or under-utilized distribution infrastructure to deploy DER projects. FOM energy storage, sited as either co-located storage or a standalone storage project — similar to VGES — would increase overall feeder hosting capacity, maximizing the size of the generating profile eligible to be deployed while maintaining Op-Flex constraints. Due in part to the complexity of implementing this new interconnection method and to issues with the accuracy (and granularity) of the existing ICA maps, a full rollout has not yet been completed. Ideally, once tested and verified, the same methodology approved for use in Rule 21 interconnections should be applied to the

[4] CPUC (California Public Utilities Commission). 2020 (August 12). *Rule 21 Working Group Four Final Report*. Issue F (Background), pp. 80-86. Available at https://gridworks.org/wp-content/uploads/2020/08/R21-WG4-Final-Report.pdf.

[5] Brockway, A.M., J. Conde, and D. Callaway. 2021. "Inequitable access to DER due to grid infrastructure limits in California." *Nature Energy*, 6(9), 1-12. Available at doi:10.1038/s41560-021-00887-6.

WDAT interconnection process, thus enabling new siting opportunities in locations where there was previously no available hosting capacity for distributed generation.

As part of its data validation process, SCE made an error that corrupted most/all of the ICA data in its entire service territory. The hosting capacity for most feeders changed, by as much as 58 percent in some cases, and the number of feeders with 0kW of available hosting capacity (due to Op-Flex constraints) increased from 60 percent to 88 percent. It was only after a timely protest from the Interstate Renewable Energy Council that SCE began the process of analyzing the entire methodology to isolate the error and validate the new data on a circuit-by-circuit level. The error analysis was not quite complete a full 10 months after the problem was first reported — impacting the developers the most. Inaccurate information has made it difficult, if not impossible in many cases, for developers to scope out potential project locations in SCE's service territory and has delayed the plan to implement Op-Flex (and limited generation profiles) in the Rule 21 interconnection process.

The delays in the VGES interconnection demonstrate the importance of the IOUs including accurate and granular feeder data in the ICA maps and performing data validation in a timely manner. Choosing an appropriate site is one of the key challenges of deploying energy storage; developers need the ability to identify cost-effective project sites and have a high degree of certainty that the information is both accurate and up to date. While there were no issues related to ICA data following the selection of Valencia Gardens as the site for the project, the unforeseen project cost increases due to required grid upgrades were enough to bring the project to a halt. Thus, the IOUs should conduct a granular feeder-by-feeder validation of existing data on an annual basis to ensure that data is reflective of current grid conditions.

CHAPTER 4: Conclusion

Lessons Learned and Key Finding

As noted under the Key Results section of the Executive Summary, despite substantial challenges and barriers, which ultimately resulted in the project not being able to move forward, the VGES project identified and experienced not only barriers but also benefits; and these resulted in valuable lessons learned for existing and future FOM projects.

Economic and Operational Benefits

The VGES project provided key lessons showing that FOM energy storage can deliver multiple important benefits, including increased capacity for renewables, improved grid operations, and revenues earnings. The earnings were projected at over $40 million per year, along with over $130 million in system-wide annual savings at year 20, including peak capacity savings, T&D lines loss savings, new transmission capacity savings, and energy cost savings. Other benefits are CO_2 and NOx reductions plus water savings. (See Appendix A, VGES Economics Forecast and Quantified Benefits, for details.) Note that the value benefits include providing local energy resilience, not quantified but certainly very valuable. The VGES project proved that FOM systems can be designed to deliver these important benefits to grid operators and ratepayers.

Barriers

Unfortunately, the VGES project experienced multiple technical, economic, and process barriers:

- A two-year major delay for interconnection approval
- Unexpected project cost increases of almost three-fold due to unexpected utility upgrades and the long interconnection application review process
- Uncertainties due to equipment changes imposed by PG&E
- Permitting issues imposed by the San Francisco Fire Department and the fire marshal that resulted in the mutual termination of the project.

To help eliminate existing policy barriers, the following policies should apply to FOM storage:

- **Renewable Market Adjusting Tariff:** A feed-in tariff, administered by the CPUC, that is designed for generators under 3 MW. In 2021, the CPUC approved new eligibility criteria allowing co-located storage.
- **Emergency Load Reduction Program:** A five-year emergency backup pilot program created in response to the August 2020 reliability crisis. Distributed generation is compensated $2/kWh for energy exported to the grid or load removed during grid reliability events.

- **Distributed Electricity Backup Assets**: Following the record peak demand in September 2022, the legislature passed Assembly Bill 205, allocating $700 million to the CEC as a Strategic Reliability Reserve. The CEC can earmark this funding through various means, including streamlined FOM interconnection to maintain reliability during peak periods.
- **Green Access Programs (also known as Community Solar):** Following the legislative mandate of Assembly Bill 2316, the CPUC was reviewing the four existing Green Access Programs: Disadvantaged Communities Green Tariff Program, Community Solar Green Tariff, and Green Tariff/Shared Renewables. Community Solar programs should include paired energy storage to maximize both grid and resilience benefits.
- **FERC Order 2222:** In September 2020, FERC approved Order 2222, allowing DERs to participate in the wholesale energy, capacity, and ancillary services markets operated by regional transmission owners and independent system operators.[6] To comply with FERC Order 2222, the California ISO amended the Distributed Energy Resources Providers program by reducing the minimum system size from 500kW to 100kW. As part of this, the increase in DER aggregations as virtual power plants should include FOM utilizing streamlined interconnection.

Proposed Solution

To achieve California's and the CEC's renewable energy goals, the project team recommends the following solutions:

- A statewide program that analyzes and designs optimal FOM distributed energy storage and solar as a system-wide feature for the California grid, complementing both BTM DER and utility scale deployments. See the proposed solution diagram in the Executive Summary, Figure ES-1. This will deliver the intended VGES project benefits as a statewide solution, utilizing FOM storage and solar to provide their multiple benefits: cost-effective and secure support for full decarbonization and electrification, improved grid operations with reduced system-wide peaks and thus lower ratepayer costs, and critical resilience for all California communities. Combined with the system-wide design for utilizing FOM solar and storage, an accurately streamlined fast-track interconnection process for FOM projects would achieve higher levels of accountability, transparency, communication, and consistency regarding timelines, costing, and design, enabling developers to deploy these systems in a timely and cost-effective manner.
- A statewide DER-FOM Program that analyzes FOM solar and energy storage across substation areas to accomplish the significant ratepayer, grid operations, decarbonization, and resilience benefits, to be administered by the CEC. This formal California DER-FOM' Program would be implemented using a CEC-approved design and

[6] Electricity Advisory Committee. 2021 (April). "FERC Order 2222: Recommendations for the U.S. Department of Energy – Outline." United States Department of Energy. Available at https://www.energy.gov/sites/default/files/2021-04/EAC%20FERC%20Order%202222%20Recommendations_Approved.pdf#:~:text=During%20the%20Electricity%20Advisory%20Committee%20%28EAC%29%20meetings%20in,DER%20aggregator%2C%20and%20state%20and%20local%20regulatory%20authorities.

deployment methodology that targets FOM solar and energy storage across all substation areas, thus achieving these critical benefits. This program would require all California utilities to accurately assess locations and sizing of FOM solar and energy storage that would benefit ratepayers, grid operations, and communities as stated, and in a timely manner using a methodology defined by the CEC. See the diagram in the Executive Summary, Figure ES-1, and the proposed program methodology framework in Appendix D.

- An important policy innovation for streamlining FOM interconnection is a fixed fee and utility pays policy — FixUP — that extends the existing BTM streamlined interconnection processes, timing, and price certainty to FOM projects. FixUP would allow FOM projects to determine whether they qualify for fixed fee interconnection, based on publicly accessible eligibility criteria. And utilities would directly pay for interconnection costs, since the benefits apply broadly. Importantly, FixUP merely treats small FOM projects in a similar manner as BTM projects of up to 1 MW. From a physical standpoint, FixUP-eligible FOM and BTM projects have identical impacts on the grid; their interconnections should, accordingly, benefit from equally straightforward processes. The Clean Coalition estimates that FixUP would yield an average of at least $25,000 in bureaucratic savings alone per FOM project. (See Appendix B for details.) Also, multiple existing policies should apply directly to streamlining FOM interconnections, as follows:
    - This proposed solution is directly aligned with the CEC's Clean Energy Reliability Investment Program, which intends to 1) expedite permitting, including implementation of the new state permitting authority at the CEC for clean energy generation and energy storage systems, and 2) address electric transmission and distribution level interconnection delays and improve interconnection review and approval processes.
- A pilot for streamlining Fast Track FOM energy storage interconnection is recommended to help achieve this proposed solution. The pilot would 1) shorten the interconnection application review process and pre-construction timelines, and 2) decrease costing and design review inefficiencies by employing modifications to the current Fast Track interconnection process. This would allow early discovery and resolution of issues, reducing the time to pull permits, from over two years to under six months, while also enabling developers to determine the best and most cost-effective solutions. See Appendix C for details regarding the pilot design and execution.
- Jurisdictions and fire departments should allow flexibility to be considered, so that densely populated areas receive exceptions as allowed by UL9540A, including construction of a concrete firewall between the BESS and other structures. See Appendix E for details.

Also, accurate and current ICA data must always be available, so that developers can determine locations where grid upgrades are not necessary and/or which upgrades are the most cost-effective.

The above enhancements would streamline FOM interconnection timing and price certainty.

Clean Coalition Contribution: The Clean Coalition possesses the required expertise for FOM solar and energy storage designs that achieve the stated benefits. Thus, the Clean Coalition can perform a key role in moderating and facilitating the DER-FOM program on behalf of the CEC, including streamlining FOM interconnection appropriately. As part of this role, the Clean Coalition would collaborate with the new U.S. DOE Interconnection Innovation e-Xchange initiative, with the purpose of accelerating the interconnection of clean energy resources on behalf of grid operations and ratepayers.

GLOSSARY AND LIST OF ACRONYMS

Term	Definition
1-BESS	one-battery energy storage system
2-BESS	two-battery energy storage system
BESS	battery energy storage system
BTM	behind the meter
CAM	contract agreement manager
CC	Clean Coalition
CEC	California Energy Commission
CFC	California Fire Code
CO_2	carbon dioxide
COD	commercial operation date
CPUC	California Public Utilities Commission
CUA	conditional use authorization
DAC-GT	Disadvantaged Communities Green Tariff Program
DER	distributed energy resources
EGI	Electric Generation Interconnection
EPIC	Electric Program Investment Charge
ESS	Energy Storage Systems
ETB	Energy Toolbase
EWB	East West Bank
FERC	Federal Energy Regulatory Commission
FixUP	a fixed-fee-and-utility-pays policy
FOM	front-of-meter
GFO	grant funding opportunity
GWh	gigawatt-hour
ICA	integration capacity analysis
IEEE	Institute of Electrical and Electronics Engineers
IOU	investor-owned utility
IPE	Independent Professional Engineer
ISO	Independent System Operator
kV	kilovolt
kVA	kilovolt-ampere
kW	kilowatt
kWdc	total installed system cost per kilowatt of DC capacity

Term	Definition
kWh	kilowatt-hour
kWp	kilowatt peak
M gal	million gallons
MW	megawatt
MWac	megawatt alternating current
MWh/MW	megawatt hours per megawatt
NOx	nitrogen oxide
Op-Flex	operational flexibility
Peaker plant	peak demand power plant
PG&E	Pacific Gas and Electric Company
POI	point of interconnection
PSPS	public safety power shutoff
PTO	permission to operate
PUD	Planned Unit Development
PV	photovoltaic
QC	Qcells USA Corp.
REP	REP Energy, Inc.
SCE	Southern California Edison
SDG&E	San Diego Gas and Electric company
SF	San Francisco
SFFD	San Francisco Fire Department
SGIA	Small Generator Interconnection Agreement
SLD	single-line diagram
sq. ft.	square feet
T&D	transmission and distribution
TAC	Technical Advisory Committee
TD&D	Technology Demonstration & Deployment
U.S. DOE	United States Department of Energy
VGES	Valencia Gardens Energy Storage
WDAT	wholesale distribution access tariff
WDT	Wholesale Distribution Tariff

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    - https://clean-coalition.org/wp-content/uploads/2021/03/Clean-Coalition-Opening-Comments-on-Track-3-Scoping-Memo-R.-19-09-009.pdf.
    - https://clean-coalition.org/wp-content/uploads/2021/09/R.-19-09-009-Clean-Coalition-Reply-Comments-on-Emergency-Proclamation.pdf.

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- https://clean-coalition.org/wp-content/uploads/2020/09/Clean-Coalition-Reply-Comments-on-R.-19-09-009-Track-2-Staff-Proposal-and-Concept-Paper.pdf.
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- https://clean-coalition.org/wp-content/uploads/2020/02/R.-19-09-009-COMMENTS-OF-THE-CLEAN-COALITION-on-Track-1-Staff-Proposal-and-IOU-Proposals.pdf.
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- R. 20-11-003 (Emergency Reliability): https://clean-coalition.org/wp-content/uploads/2021/02/Clean-Coalition-Opening-Comments-on-R.-20-11-003-Proposed-Decision.pdf.
- DER Action Plan 2.0: https://clean-coalition.org/wp-content/uploads/2021/10/Clean-Coalition-Comments-on-Draft-DER-Action-Plan-2.0.pdf.

A full listing and history of the Clean Coalition's regulatory filings can be found at https://clean-coalition.org/regulatory-filings/

Publications

Stewart, L. 2021 (June/July). "Keeping The Lights on With Microgrids." *Bay Area Monitor*. Available at https://bayareamonitor.org/article/keeping-the-lights-on-with-microgrids/.

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Project Deliverables

The follow key VGES technical project deliverables were developed and submitted to the CEC:

- VGES FOM Interconnection Case Study. Available at https://clean-coalition.org/community-microgrids/valencia-gardens-energy-storage-project/.
- VGES 2-Page Overview. Available at https://clean-coalition.org/wp-content/uploads/2021/05/VGES-2-page-overview-06_rf-11-May-2021.pdf.
- Initial Final Fact Sheet. Available upon email request to pubs@energy.ca.gov.
- Project Final Fact Sheet. Available upon email request to pubs@energy.ca.gov.

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Appendix A: VGES Economics Forecast and Quantified Benefits

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APPENDIX A:
VGES Economics Forecast & Quantified Benefits

Table A-1 provides the details regarding the operational revenue and cost projections for the VGES system, if deployed.

Table A-1: Operational Revenue and Cost Projections for the VGES System

		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Assumptions
Operational Cash Flows	Cost Basis											ESS Power (kW)
Electricity Revenues												ESS Energy (kWh)
Wholesale Sale Price ($/MWh)	Selected evening/peak hours	$ 63.39	$ 64.66	$ 65.30	$ 65.96	$ 66.61	$ 67.28	$ 67.95	$ 68.63	$ 69.32	$ 70.01	Bayshore node. NP15 forward curve
Electricty Sold (MWh)	92%	331.23	323.28	315.52	307.95	300.56	293.35	286.31	279.44	272.73	266.18	RT efficiency
Wholesale Sale Revenue ($)		$ 20,996.18	$ 20,902.12	$ 20,604.47	$ 20,311.07	$ 20,021.84	$ 19,736.73	$ 19,455.68	$ 19,178.63	$ 18,905.52	$ 18,636.31	
Ancillary Services Revenue												
Regulation Revenue ($)	Selected by arbitrage schedule	$ 12,576.29	$ 12,576.29	$ 12,576.29	$ 12,576.29	$ 12,576.29	$ 12,576.29	$ 12,576.29	$ 12,576.29	$ 12,576.29	$ 12,576.29	Reg up and Reg down - based on Caiso_ExpPrices
Spinning Revenue ($)	(not used in calculations)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	All energy to Reg b/c higher pricing
Resource Adequacy [200kW] ($/kW/y)	$ 4.75	$ 11,400.00	$ 11,400.00	$ 11,400.00	$ 11,400.00	$ 11,400.00	$ 11,400.00	$ 11,400.00	$ 11,400.00	$ 11,400.00	$ 11,400.00	Based on "2018 RA Report" - 85th percentile local RA for PG&E ($4.75)
Additional operation cycle (CAISO AS)	(not used in calculations)	$ 2647.77	$ 2647.77	$ 2647.77	$ 2647.77	$ 2647.77	$ 2647.77	$ 2647.77	$ 2647.77	$ 2647.77	$ 2647.77	<- Requires second battery charge cycle - not worth it (not included in calculations)
Demand Response	(not used in calculations)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	DR conflicts with higher value ancillary services
Total Ancillary Revenues		$ 23,976.29	$ 23,976.29	$ 23,976.29	$ 23,976.29	$ 23,976.29	$ 23,976.29	$ 23,976.29	$ 23,976.29	$ 23,976.29	$ 23,976.29	
Total Revenues		$ 44,972.48	$ 44,878.41	$ 44,580.77	$ 44,287.36	$ 43,998.13	$ 43,713.02	$ 43,431.97	$ 43,154.92	$ 42,881.82	$ 42,612.60	
Project Operational Expenses												
Scheduling Coordinator Rate ($/Month)	$ 2,400.00	$ 2400.00	$ 2400.00	$ 2400.00	$ 2400.00	$ 2400.00	$ 2400.00	$ 2400.00	$ 2400.00	$ 2400.00	$ 2400.00	Multiple Quotes - starting at $3k/month
Coordinated group size (kW, <=10k)	1,000	$ 1,200.00	$ 1,200.00	$ 1,200.00	$ 1,200.00	$ 1,200.00	$ 1,200.00	$ 1,200.00	$ 1,200.00	$ 1,200.00	$ 1,200.00	Max charge assuming no SC aggregation
Scheduling Coordinator Capacity Fee ($/mo/kWh)	$ 0.20	$ 219.20	$ 219.20	$ 219.20	$ 219.20	$ 219.20	$ 219.20	$ 219.20	$ 219.20	$ 219.20	$ 219.20	
Scheduling Coordinator Expense ($ per year)	Annual Total	$ 17,030.40	$ 17,030.40	$ 17,030.40	$ 17,030.40	$ 17,030.40	$ 17,030.40	$ 17,030.40	$ 17,030.40	$ 17,030.40	$ 17,030.40	
Market Expenses												
Wholesale Purchase Price ($/MWh)	Selected mid-day hours	$ 29.06	$ 29.65	$ 30.24	$ 30.84	$ 31.46	$ 32.09	$ 32.73	$ 33.39	$ 34.05	$ 34.73	
Electricity Purchased (MWh)		360	351	343	335	327	319	311	304	296	289	365 cycles * 90% utilization of 1096 kWh capcity * 2.4% annual degredation
Wholesale Purchase Cost ($)		$ 10,464.13	$ 10,417.26	$ 10,370.59	$ 10,324.13	$ 10,277.87	$ 10,231.83	$ 10,185.99	$ 10,140.36	$ 10,094.93	$ 10,049.70	
Net Market Revenues		$ 17,477.94	$ 17,430.76	$ 17,179.78	$ 16,932.83	$ 16,689.86	$ 16,450.79	$ 16,215.58	$ 15,984.16	$ 15,756.49	$ 15,532.50	
Operational Expenses												
Site Lease	$0k/mo	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Site O&M	$4.2k/year	$ 4,200.00	$ 4,200.00	$ 4,200.00	$ 4,200.00	$ 4,200.00	$ 4,200.00	$ 4,200.00	$ 4,200.00	$ 4,200.00	$ 4,200.00	
Site Maintenance	$400/mo	$ 4,800.00	$ 4,800.00	$ 4,800.00	$ 4,800.00	$ 4,800.00	$ 4,800.00	$ 4,800.00	$ 4,800.00	$ 4,800.00	$ 4,800.00	
Internet	$100/mo	$ 1,200.00	$ 1,200.00	$ 1,200.00	$ 1,200.00	$ 1,200.00	$ 1,200.00	$ 1,200.00	$ 1,200.00	$ 1,200.00	$ 1,200.00	
Total Expenses ($)		$ 37,694.53	$ 37,647.66	$ 37,600.99	$ 37,554.53	$ 37,508.27	$ 37,462.23	$ 37,416.39	$ 37,370.76	$ 37,325.33	$ 37,280.10	
Net Total Operational Cash Flow ($)	*	$ 7,277.94	$ 7,230.76	$ 6,979.78	$ 6,732.83	$ 6,489.86	$ 6,250.79	$ 6,015.58	$ 5,784.16	$ 5,556.49	$ 5,332.50	

		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	
Project Owner Cash Flows												
Project Revenues		$ 7,277.94	$ 7,230.76	$ 6,979.78	$ 6,732.83	$ 6,489.86	$ 6,250.79	$ 6,015.58	$ 5,784.16	$ 5,556.49	$ 5,332.50	
Cap Ex (total installed cost of storage facility)	$ 1,710,942											
Cap Ex repayment (est.)	$ 1,710,942	$124,415.64	$124,415.64	$124,415.64	$124,415.64	$124,415.64	$124,415.64	$124,415.64	$124,415.64	$124,415.64	$124,415.64	20yr loan @ 4% interest
VGES Net Cap Ex after CEC grant												
Net Cap Ex repayment (est.)	$ 1,400,872	$101,868.00	$101,868.00	$101,868.00	$101,868.00	$101,868.00	$101,868.00	$101,868.00	$101,868.00	$101,868.00	$101,868.00	20yr loan @ 4% interest
Replacement cell cost (2.4% annual degredation)	$ 428,891	$ 14,296.37	$ 14,296.37	$ 14,296.37	$ 14,296.37	$ 14,296.37	$ 14,296.37	$ 14,296.37	$ 14,296.37	$ 14,296.37	$ 14,296.37	annualized cost of replacement @ year 15, assuming 50% cost reduction from 2020 cost basis
Replacement inverter (15yr)	$ 100,000	$ 6,666.67	$ 6,666.67	$ 6,666.67	$ 6,666.67	$ 6,666.67	$ 6,666.67	$ 6,666.67	$ 6,666.67	$ 6,666.67	$ 6,666.67	annualized cost of replacement @ year 15, assuming 2020 cost basis
Net Project Owner Cash Flow												
Added - interconnection upgrade cap ex:												
New Transformer	$ 86,263											
Recloser	$ 87,500											
Cost of Ownership charge	$ 142,124											
underground vault	$ 56,736											
Total	$ 372,623											

Below are the details of what was provided in the VGES project Narrative and Scope of Work under EPC-16-073 providing the quantitative estimated cost benefits of FOM energy storage, based on the VGES potential as an example.

Quantitative estimates of potential benefits of a 25 percent increase in hosting capacity as would have been demonstrated by VGES, and subsequent impact on California electricity ratepayers if adopted statewide is described below based on a per MW basis and a total projected impact of 1,800 MW of additional PV deployment over 20 years, an increase in annual deployments of 90 megawatts per year.

PV adoption and deployment is highly price sensitive and is therefore constrained by hosting capacity limits above which substantial additional costs are incurred for grid upgrades. ICA methodology is being developed for demand response program application across the three major IOUs under CPUC jurisdiction. Existing hosting capacity is highly location specific and varies across the length of each primary feeder line, secondary branch, and single-phase circuit. In addition, hosting capacity on one circuit is influenced by the addition of load and generation on other electrically related circuits, meaning that the aggregate PV hosting capacity is less than the sum of capacities of all circuits. Testing for five most common limiting factors, results from the demand response program Demonstration A of ICA methodologies on multiple Distribution Planning Areas across California indicate average limits to generation hosting capacity that can be added at any location on the primary three-phase distribution feeders without violating a testing threshold is approximately 1 MW in urban areas and 500kW in rural areas. California has approximately 1,800 distribution substations with typically three to four primary feeders. For illustrative purposes it is therefore safe to assume that a 25 percent increase in hosting capacity will increase ICA results by 1 MW per substation, for a potential system-wide increase of 1,800 MW. Results from the ICA further indicate that 625 kWh of battery capacity are required for each 1 MW increase in PV hosting capacity.

It should be noted that the actual impact of energy storage on PV hosting capacity will be greater if the batteries are operated primarily for the purposes of PV integration, however the added cost of dedicating storage capacity to this function would make such deployment unlikely. The VGES project was intended to demonstrate the opportunity for battery deployment to be fully financially supported through participation in available markets and revenue operations, and determine the degree to which such operating profiles will support higher PV penetration with optimization for maximum value and cost effectiveness. Benefits are estimated based on the 25 percent increase in hosting capacity being achieved and resulting in increased deployment of distributed PV. As such, the benefits are associated with added local PV deployment in 1 MW increments up to the full utilization of the increased hosting capacity. These should be considered net benefits as no additional cost is assumed for the batteries to create increased hosting capacity as a secondary effect of their deployment for market participation and related revenues. The addition of distributed ES resources into these markets will increase completion and reduce marginal costs of procurement from these markets.

Impacts and benefits are catalogued in the following Table A-2. Methodologies, assumptions, and citations are summarized below the table.

Table A-2: Impacts and Benefits of Energy Storage

Impacts	Annual per MW deployed	20 year cumulative per MW	Annual 90 MW addition system-wide	System-wide annual total at year 20
Formula	Base value	Base value x 20	Base value x 90	Base value x 1800
Peak Capacity Savings	$24,000 @ 20% ECC	$480,000	$2,160,000	$43,200,000
T&D Line Loss Savings	$11,835	$236,700	$1,065,150	$21,303,000
New Transmission Capacity Savings	$30,500	$610,000	$2,745,000	$54,900,000
Energy Purchase Reduction	1,550MWh	31,000MWh	139,500MWh	2,790,000MWh
Energy Cost Savings	$20,000	$20,000*	$1,800,000	$36,000,000
Reliability Value	$1,766	$35,320	$158,900	$3,178,800
CO_2 Reduction	513 tonnes	10,260 tonnes	46,170 tonnes	923,400 tonnes
NOx Reduction	1.39 tonnes	27.85 tonnes	125 tonnes	2,506 tonnes
Water Savings	0.03 M gal	0.6 M gal	2.7 M gal	54 M gal

M gal = million gallons; MWh = megawatt hours
* Savings on initial installed cost of energy may be reflected over equipment life x energy price.

Impacts and Benefits: Methodologies and Assumptions

- **Peak Capacity Savings:** Reduction in the summer peak centralized electricity generation will occur because of increases in distributed renewable generation, and distributed PV has a high aggregate availability during these hours, exceeding 80 percent. On this basis, added PV will provide $94.40 value per year per kW of effective capacity. However, with increasing supply of solar energy during peak periods and the resulting shift of net peak from non-solar resources toward 6pm, the effective capacity may be reduced to 20 percent, yielding a value of $24/kW/year, equaling $24,000 annually or $0.48 million over 20 years from 1 MW PV capacity. A 90 MW increase in annual deployments of distributed PV would yield $2.2 million in new additional annual peak reduction per year. Over 20 years 1,800 MW additional statewide deployments would result in $43 million in savings based on the lower value.
- **Transmission & Distribution Line Loss Savings:** Based on PG&E Bay Area reported loss rates, combined avoided 3 percent transmission and 2 percent distribution avoided losses from distributed generation (DG) average 5 percent, or 79 MWh per year for each 1 MW of PV distributed generation installed. At an average

current retail value of 15¢/kWh the value of avoided losses is $11,835 per year, totaling $236,700 over 20 years. The use of average loss values is conservative as the marginal rate of line loss is twice the average rate of loss, and any reduction will actually realize the marginal rate. Assuming conservatively that 5 percent of total annual consumption may be sourced through distributed PV with existing hosting capacity, a 25 percent increase would meet 1.25 percent (4 terawatt-hours) of total statewide annual load, yielding 0.04 percent reduced transmission losses statewide, saving 112 gigawatt-hours (GWh) of energy annually for a value of $5,600,000 at $50/MWh, and 0.02 percent reduced distribution losses statewide, saving 75GWh of energy distribution losses annually, for a value of $3,700,000.

- **New Transmission Capacity Savings:** Reduced demand on transmission will reduce or defer the need for additional investment to expand transmission capacity, slowing the growth in future transmission access charge rates and reducing charges across the board for all energy utilizing the system. Based on the average costs of new capacity investments and repayment, each 1 MW of added PV distributed generation capacity will reduce the need for added transmission capacity investment by 0.005 percent relative to California ISO Business-As-Usual projections and the related growth in transmission access charge rates. This will be realized as $30,500 in annual system wide savings from a 0.00012¢/kWh reduction transmission access charge rates applied to the 254,000 GWh consumed within California ISO transmission system electricity by 2020.
- **Reduced Energy Purchases:** 1,550MWh/MW; fully deployed 2,800 GWh.
- **Energy cost reductions:** The additional PV hosting capacity, identified through modeling of ES enhancements, will result in this added PV avoiding an average of $20,000 per MW in additional study costs through increased Fast Track interconnection review to determine that upgrades would not be needed. Where studies and upgrades are indicated at higher penetration levels, the improved base hosting capacity and presence of battery related mitigation factors may identify newly available operational mitigation alternatives or lower cost upgrades. Interconnection costs have averaged $2-300,000 per MW in recent years in SCE & PG&E territories, representing 10 percent of total installed costs. A conservative 10 percent average reduction in these interconnection costs will therefore represent a 1 percent reduction in the cost of energy from these facilities for ratepayers, approximately $1.8 million per year at full ICA deployment. This is particularly applicable to customer rates paid under California's Green Tariff Shared Renewables and Enhanced Community Renewables state mandated utility subscriber programs, and to Community Choice Aggregator programs focused on local resources but will also be reflected in lower marginal prices for general energy procurement.
- **Reliability and Resilience:** $883 per small business from avoided average annual local outage (assumes two businesses per MW).

- **Emission Reduction:** Greenhouse gas reduction – 0.331 metric tons per MWh, 513 metric tons per megawatt-year at 1,550MWh/MW; 923,400 metric tons annually if 1,800 MW from full deployment.
- NOx reduction - 3,070 pounds per MW; 110,000 pounds fully deployed.
- As qualifying facilities contributing to California's Renewable Portfolio Standard, at a base price of $10/metric ton for avoided CO_2, the annual market value of emission reduction is $5,130; however, the market rate is liable to substantially exceed $10/metric ton in future years. Mortality reduction of 0.004/MW; 7.2 persons per year if fully deployed. Reduction in workdays lost of 0.51 days/MW; 918 days if fully deployed.
- **Water Use Reduction:** Each 1 MW of PV would save nearly 0.3 million gallons of water use per year. Thermal generation, including both fossil and nuclear facilities, requires significant water use for cooling. Combined-Cycle Natural Gas facilities with cooling towers consume 0.7 cubic meters of water per MWh through evaporation, and other conventional and nuclear facilities require up to three times this quantity.

ENERGY RESEARCH AND DEVELOPMENT DIVISION

Appendix B: Fixed Fee and Utility Pays (FixUP) proposal for small FOM interconnections

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APPENDIX B: Fixed Fee and Utility Pays (FixUP) proposal for small FOM interconnections

Goal

The goal of the FixUP policy innovation is to extend the BTM streamlined interconnection processes, timing, and price certainty to small FOM projects.

Overview

FOM interconnection is hobbled by numerous barriers, but two of the biggest barriers can be eliminated with the straightforward FixUP policy innovations. FixUP will allow FOM projects to determine whether they qualify for fixed fee interconnection, based on publicly accessible eligibility criteria. Further, all FOM projects that are no greater than 1 MW will avoid the bureaucratically complex and unnecessary process of having to pay for grid upgrades and then legally deed those upgrades to the utility, as well as avoiding the need for an escrow account, which eliminates an additional bundle of complexities and costs. The Clean Coalition estimates that FixUP will yield an average of at least **$25,000 in bureaucratic savings alone** per FOM project.

Importantly, FixUP merely treats small FOM projects in a similar manner to BTM projects of up to 1 MW. From a physical standpoint, FixUP-eligible FOM and BTM projects have identical impacts on the grid; their interconnections should benefit from equally straightforward processes accordingly which is far from the case today, with FOM interconnection processes being far more costly, lengthy, and uncertain. Unfortunately, existing FOM interconnection processes cause the elimination of the vast majority of eligible projects.

FixUP resolves these issues by providing deterministic and reasonable costs upfront and eliminating the costly, time-consuming, and unnecessary bureaucratic complexity that exists today.

Fixed Fee eligibility

FOM projects will be eligible for Fixed Fee pricing if they meet the following three criteria:

- Sized under 1 MWac (megawatt alternating current)
- Sited on the property of a utility customer.
- In aggregate, sized less than the associated service rating of the site where the FOM project will be located. For example, projects sited at an apartment complex with an aggregate service rating of 800 kW will be Fixed Fee eligible for FOM projects that are less than 800 kW in aggregate capacity.

Fixed Fee amount

The Fixed Fee amount will be set at a revenue-neutral level, based on average actual costs incurred by the utility. Initially, $10,000 is estimated to be appropriate for the Fixed Fee amount and covers the Pre-Application Reports, Fast Track (FT) Application, review, and approval, and Fast Track Supplemental Review. See the tabular view below (Table B-1). Of course, the Fixed Fee does not include facility costs on the FOM project side of the point of common coupling, as those are costs of the project and are always owned as part of the project.

Table B-1: Breakdown of initial FOM interconnection Fixed Fee amount

Description	Fees
Pre-application report	$600
Application submittal / Scoping meeting (Fast Track and standardized interconnection fee approval)	$800
Technical study / Supplemental Review	$2,500
Results review meetings	$750
Pre-construction meetings, final construction drawings, engineering costing, site visits for inspection, and actual interconnection	$5,350
Total:	**$10,000**

Utility Pays Process

For FOM projects that are no larger than 1 MW and that do not meet all of the other Fixed Fee eligibility criteria, the utility will still directly pay for any interconnection costs to streamline the interconnection process for these small FOM projects and then recover those costs based on standardized unit costs, which each utility already publishes annually. In addition to the Fixed Fee, the projects will pay fixed fees for required grid upgrades based on the published equipment unit costs. The Utility Pays approach will provide significant streamlining and price certainty by eliminating the complex and unnecessary processes associated with paying the utility to perform grid upgrades and then having to deed those same grid upgrades to the utility. This also avoids the need for an escrow account, which eliminates an additional bundle of complexities and costs. Importantly, Utility Pays streamlines processes for the utilities too, thereby saving ratepayers from paying for unnecessary and wasteful bureaucracy on the utility side.

Based on PG&E's current Wholesale Distribution Tariff (WDT) Unit Cost Guide, (Table B-2) the following standard costs are examples of fees that could be added to the Fixed Fee amount for FOM projects up to 1 MW that do not meet the remaining Fixed Fee eligibility criteria:

Table B-2: One section of PG&E's WDT Unit Cost Guide

Grounding/Stabilizing Transformer- Padmounted	$52,000
Conductor (Per feet) - Overhead-Urban	$220/ft (Bay cost)
Reconductor (Per feet) - Overhead-Rural	$160/ft (Non-Bay cost)
Reconductor (Per feet) - UG	$260/ft (Non-Bay); $315/ft (Bay cost)
Overhead Fuses	$10,000

With an upfront fee-based structure for all FOM projects of up to 1 MW, FixUP streamlines the interconnection process for small FOM projects, including by eliminating the complex and unnecessary deeding process — saving time, energy, and money for all parties involved, including ratepayers.

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Appendix C: Pilot for Streamlining Fast Track FOM Energy Storage Interconnection

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APPENDIX C:
Pilot for Streamlining Fast Track FOM Energy Storage Interconnection

To achieve the goals for Fast Track Front-of-Meter Energy Storage Interconnection, a Pilot should be deployed that includes the following:

- **A more complete application package from the customer of record** (including proposed point of interconnection [POI], point of common coupling, site generation size)
    - The interconnection applicant will be required to submit a more complete package, ready for detailed analysis.
- **Scoping review merged into technical analysis and mandatory field meeting**
    - This step allows for early exploration of alternative solutions to PG&E discretionary thresholds.
    - Requiring all the relevant PG&E departments to meet early with the applicant to review both technical and construction issues, and to begin early resolution of any potential issues that have been uncovered, will prevent issues from arising later in the process.
- **Final design and costing locked in early**
    - The financial burden of changes (cost and/or design) that are made after the technical analysis and mandated field meeting is placed on PG&E.
- **Reduced costs** for interconnection facilities upgrades and design changes
- **Shortened timeline gap** between SGIA/financial security deposit phase to pre-construction/permit-ready status

Accelerating the application process to finish in six months depends upon the following elements, which require the applicant to provide more actionable information upfront. This enhanced application will allow the utilities to bring the process area experts together early in the sequence to analyze the site needs and constraints, ensuring that potential issues are uncovered early in the process, thus giving the applicant time to resolve them in a cost-effective manner.

Participant eligibility

- Interconnection applicant projects will be eligible to participate in the pilot and will be guaranteed Fast Track status throughout the application process if they meet these requirements:
  - Are no larger than 1 MWac (if at 1MWac or larger, use of hardware/software limiting solutions is to be considered).
  - Are able to interconnect at locations where no significant grid upgrades are required (as determined by engineering analysis and field meeting).

Enhanced application package

- The application package must include the SLD, site plans, site control documents, generator size, and proposed POI & point of common coupling.
- This completeness allows all the reviewers to apply their varying expertise to assess all of the potential issues or needed changes early in the review process, rather than waiting for more input to be received from the applicant over a longer period of time.

Technical analysis prior to field meeting (received by applicant minimum of five days prior to field meeting)

- Analyze impact of generation on PG&E's electrical system. Show needed capital improvements to PG&E's electrical system and initial cost estimates to ensure safety and reliability of the grid. Distribution upgrades to be triggered by the generator.

Mandated field meeting with PG&E service planning, interconnection, engineering, field inspector, and project developer

- This site meeting is required to complete the physical site inspection, design review, and interconnection review, and determine any necessary adjustments that may be required on the utility grid.
- Combining the expertise of the reviewers early in the process reduces the uncertainty that plagued the VGES project. This mandated meeting ensures that all the reviewers have combined their expertise in a timely and effective manner.

Signoff on design and costs

- No additional design or costing reviews will be allowed after signoff. Any design and or costing changes after this point are to be paid for by PG&E.
- If the proper review and assessment energy is expended early in the process, there should be no surprises later.

Execute SGIA/financial security deposit posting

- Thirty days should be sufficient time to finish processing the Interconnection Application after the design and costs are signed off.
- It should take less than two weeks to post the security deposit.

Pre-construction phase

- PG&E to host a pre-construction site meeting.
- PG&E's construction sketch is **required** to be shared at this meeting. Any design and/or costing changes from the SGIA are to be paid for by PG&E.

PG&E construction drawing

- PG&E is to furnish the construction drawing, allowing the project developer to pull permits.

OK to pull permits

- Applicants can begin construction.
- NOTE: See Exhibit D for more details regarding permitting issues experienced by the VGES project.

CALIFORNIA ENERGY COMMISSION

ENERGY RESEARCH AND DEVELOPMENT DIVISION

Appendix D: Methodology Framework for CEC-implemented DER FOM Program

July 2024 | CEC-500-2024-090

APPENDIX D: Methodology Framework for CEC-implemented DER FOM Program

The DER-FOM Program as described above would design and optimize FOM solar and energy storage as a system-wide solution for the California grid. The methodology for determining an optimal amount of FOM solar and storage that would be the most effective within substations would be defined and approved by the CEC with help from qualified contributors as needed. This methodology would utilize the following as the general criteria and key objectives:

1. **Peak Reduction:** The amount of FOM solar and energy storage that would achieve a reduction in existing peak amounts at a substation, resulting in reduced costs for all ratepayers due to reduced requirement for long-distance energy infrastructure and/or peaker plants.
2. **Decarbonization Support:** The amount of FOM energy storage that would enable increasing the local solar within a substation area to satisfy the full decarbonization and electrification load profile for the substation, resulting in reduced costs for all ratepayers due to reduced requirement for long-distance energy infrastructure that otherwise would be required in order to support the increased decarbonization load profile at the substation.
3. **Required Resilience:** The amount of FOM solar combined with energy storage, and at what specific locations, which would satisfy each substation area's requirement for providing energy resilience to essential services for communities.

The outcome of the above would be results that are published online detailing specific FOM solar and energy storage locations and sizes, as well as key locations that require resilience, thus enabling targeted and fast deployments based on the results. Note that the criteria stated above is directional in order for the CEC to generate more detailed criteria which would then be implemented by the California utilities in a timely manner. This criteria would include both collaboration with communities and optimizing DER-FOM solutions to achieve all values and including grid services. See the diagram showcasing this in the Executive Summary.

All utilities would publish the results of their DER-FOM assessments such that FOM solar and energy storage providers can review the outcome of the assessments, then propose specific installations - system sizing, locations, and features - based on the assessment results. The resulting interconnection requests will then be approved very quickly using an applied Fast Track DER-FOM interconnection procedure.

As a key component of this solution, the DER-FOM program will provide substantial support for the state's requirement to decarbonize by electrifying transportation, homes, and buildings. Achieving a much more robust market for FOM solar and energy storage as outlined will support the substantial load increases required by this need to electrify our communities – and with a more optimal and cost-effective solution across the entire grid infrastructure to accomplish better grid management, load supply and balancing, and required resilience for California communities.

ENERGY RESEARCH AND DEVELOPMENT DIVISION

Appendix E: VGES Permitting Issues

July 2024 | CEC-500-2024-090

APPENDIX E:
VGES Permitting Issues

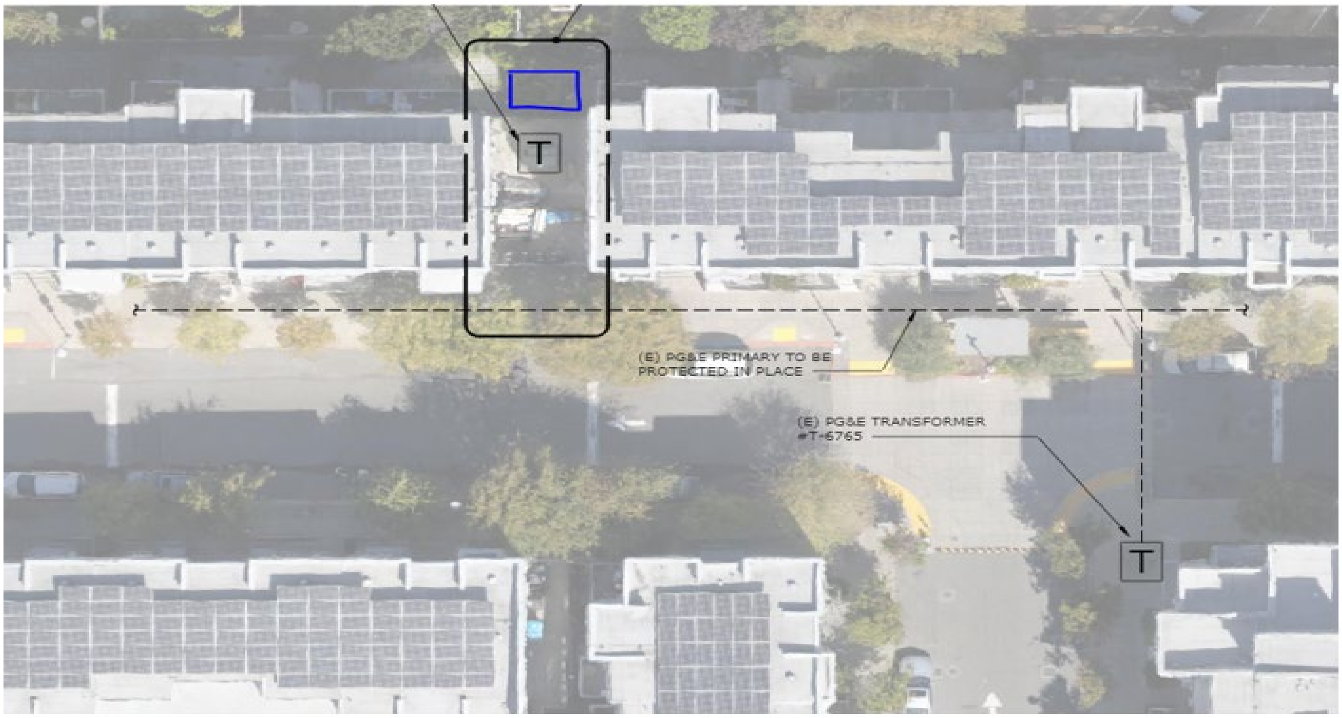
City of San Francisco:

- The 2019 California Fire Code (CFC) Section 1206.1.5 indicates that large-scale fire testing shall be conducted in accordance with UL 9540A.
- Section 1206.8 of the 2019 CFC covers outdoor installation of Energy Storage Systems (ESS). ESS located within 100 feet from buildings, lot lines, public ways, etc. are considered installations near exposures, and will need to follow Section 1206.5 maximum allowed quantity, size, and separation guidelines.
    - Section 1206.5 permits a maximum allowed quantity of 600 kWh of lithium ESS.
    - Section 1206.5.1 requires ESS to be segregated into groups not exceeding 50 kWh. Each group shall be separated by three feet (excluding non-combustible enclosure walls).
        - Section 1206.5.1 Exception 2 states fire code official can approve smaller separations with large-scale fire testing complying with Section 1206.1.5.
    - Section 1206.8.3 requires ESS located outdoors to have a 10 feet separation from exposures (lot lines, public ways, buildings, hazards, etc.) and 10 feet from path of egress.
- Reduced separation distance: code exceptions that authorize the fire code official to approve a reduced separation distance based on large-scale fire testing are not being considered for the VGES site due to high-density population status; San Francisco is following the base CFC code.
- For locations where City of San Francisco considers as a densely populated site, they will only go reference base CFC code and will not provide the exception approval for the UL9540A.

Full Explanation of City of San Francisco Codes Requirements based on VGES Example:

The City of San Francisco considers the VGES site as a densely populated area. They will only reference base CFC code and will not provide approval for any exception allowed by UL9540A. The VGES project ESS (marked blue in Figure E-1 below) is in between two apartments; hence the fire department considers it to be in a densely populated area. Since the VGES project was previously submitted to the City of San Francisco, fire officials evaluated the project using both the 2019 CFC, and the 2016 CFC. This is the reason for references to section 608, which is the section that covered energy storage systems in the 2016 CFC. Section 608 was relocated to Section 1206 for the 2019 CFC. All future projects should be evaluated using the 2019 CFC.

Figure E-1: VGES Proposed Energy Storage Installation Site Location



Fire Department Feedback:

- CFC ESS regulations have been evolving, and over time, becoming more specific
- For guidance on interpretation of 2016 Section 608, 2019 (7/1/21) Section 1206 was taken into consideration
- The VGES project is considered to be an "installation near exposures", where Maximum Allowable Quantity and Size & Separation applies (if your project was more than 100 feet from buildings, lot lines, etc., then they would not)
    - Maximum Allowable Quantity: your project currently proposes a lithium ESS under 600 kWh; compliant with both 2016 & 2019 code cycles
    - Size & Separation: Section 608 permits individual lithium ESS to be no more than 250 kWh, by exception, with three feet separation; whereas Section 1206 requires ESS to not exceed 50 kWh, with no exception for lithium provided, and separated by three feet (excluding non-combustible enclosure walls)
    - Outdoor Clearance to Exposures: Section 608 requires 5 feet separation from exposures (lot lines, public ways, buildings, hazards, etc.) and 10 feet from path of egress; whereas, Section 1206 requires 10 feet separation from exposures (with few exceptions) and 10 feet from path of egress
- Reduced separation distance: code exceptions that authorize the fire code official to approve a reduced separation distance based on large-scale fire testing are not being considered for our high-density population; SF is following the base CFC code

Please find the links below for both CFC 2016 section 608 and CFC 2019 section 1206,

- https://up.codes/viewer/california/ca-fire-code-2016/chapter/6/building-services-and-systems#608
- https://up.codes/viewer/california/ca-fire-code-2019/chapter/12/energy-systems#1206

The CFC 2016 section 608 requires ESS to be no more than 250kWh or should have three feet separation.

The CFC 2019 states groups not exceeding 50kWh and should be separated by three feet between each group.

Both codes mention the inspector can approve larger capacities and smaller distances based on the ESS system complying to large scale fire testing UL9540A. ST 556KWH-250UD system has a UL9540 certificate so it means Electrical/mechanical/HVAC/Fire suppression system was verified. And the UL9540A Test was successfully conducted and passed.

Unfortunately, the City of San Francisco considered the VGES project as "Installation near exposure" due to the energy storage location being less than 100 feet away from the building. Since the City of San Francisco considered the VGES site as a densely populated site, they would only approve the base CFC code and would not provide the exception approval for the UL9540A.

ENERGY RESEARCH AND DEVELOPMENT DIVISION

Appendix F: VGES Project Progress (Historical)

July 2024 | CEC-500-2024-090

APPENDIX F:
VGES Project Progress (Historical)

This section contains historical information on the VGES project progress specifically the PG&E FOM interconnection process (challenges, delays to schedule, unexpected additional incurred project costs), and the permitting restrictions imposed by the City of San Francisco Fire Marsal.

How are we doing compared to our plan (historical)

5/3/2022: Quenby Lum notifies Craig Lewis and Wendy Boyle that she has been instructed to issue a full Stop Work Order noting that no further work is to be done on the project with the exception of the Project Close-out preparation and planning activities.

3/25/2022:

- Follow on call with QC team: Reducing the system size to 50 kWh is not economically feasible to QC; QC sees no other viable pathway, hence must pull out from the VGES project.
- Clean Coalition (CC) has call with Energy Toolbase (ETB) to gauge their continued interest in VGES; per ETB they are interested in the project, however based on the San Francisco Fire Department (SFFD) 100-foot requirement and the possible/proposed 50 kWh system size reduction – the reduced system size does not fit within their business model, and the constraints with SFFD raises to many risk for ETB with finding alternative solutions.
- CC moving forward with the two viable pathways: (1) proposing to the CEC to refocus SOW to be a paper study – CC will update the Interconnection Case Study and develop a proposed budget amendment re-allocating remaining funds accordingly, and (2) determine remaining budget for termination of the entire project.

3/24/2022: Follow up email from Craig to QC: inquiring if reducing the battery to 50 kWh will be acceptable to SFFD for the VGES project.

3/22/2022, Project Review webcon with QC: per feedback from SFFD on the inclusion of a concrete firewall will not be acceptable; hence, SFFD not willing to deviate from requirements or alternative solutions.

3/18/2022:

- Mike Gravely speaks with Hatice Gecol (another CEC contract agreement manager [CAM]) who is managing another FOM project; per email from Hatice dated 3/18/2022, she spoke with HSU/Schatz Energy Research Center Team (FTM Airport Microgrid). They said that if a fire wall (concrete wall) is built between the Battery Storage and other structures, 100-foot space requirement can be waived.

- Craig sends email to QC with the following feedback from CEC call:
    - Other CEC grantees have encountered similar fire-safety, and the CEC has found that fire authorities will waive all distance requirements with the inclusion of a firewall (like a concrete wall) in the design, between the BESS and other structures. Hence, QC should vet this option with the SFFD ASAP.
    - Although the initial feedback from the CEC is that a major change is possible, including potentially a change of location and/or to a BTM configuration, any major change would require a robust approval process that culminates with a favorable vote by the CEC Commissioners. Such a process would likely require several months.
    - Along with the specific project outcomes of any possible pathways that the combined CC/QC team wish to pitch to the CEC, including locations/ configurations etc., estimated budgets need to be assembled. These budgets will be pertinent to decision-making, and given that terminating VGES is one possible pathway, a budget for the termination pathway needs to be assembled. Unless QC plans to take delivery of the BESS regardless, without any CEC grant reimbursement, then the termination pathway needs to be assembled quickly, including all QC costs that have been incurred to date, along with the BESS restocking cost.
    - If one or more alternate sites are pitched, the best likelihood of CEC approval will be in locations that are within Disadvantaged Communities, as determined by CalEnviroScreen.
    - Other than time to assemble the prospective pathways noted above, no additional costs should be incurred on VGES by the CC or QC.
- Qcells reaches out to SFFD to find out if inclusion like a concrete firewall will be accepted.

Report out during 3/17/2022 Project Review webcon Clean Coalition (Craig & Wendy) and CEC (Quenby & Mike Gravely): Discussion - feedback from Fire Marshall and options

Craig's three options from his 3/16/2022 email to Quenby are as follows and Mike's input:

1) Allow QC to site the BESS at a new location, ideally in a BTM configuration.
2) Allow the CC to facilitate a new Subcontractor to replace QC. Importantly, the new Subcontractor would need to bring a lithium iron phosphate chemistry that should be able to preempt the SFFD requirement for 100-foot separation. Note that QC has accumulated about $75k of eligible VGES billables, not counting the cost of the BESS which I believe QC could use in a different project if it were to assign VGES to a new Subcontractor. As you might recall, ETB is a viable candidate to serve as the new Subcontractor, because I vetted ETB early last year when seeking a replacement for

Pathion – and ETB has expressed continued interest in VGES, as recently as a couple months ago.

3) Terminate the VGES project altogether.

Mike's feedback:

Been down the road before with another Recipient wanting to go BTM; grant funding opportunity (GFO) is very specific that is FOM; but still having issues with this other Recipient.

Option 1 & 2 requires a Business Meeting which is a three to four months delay.

The only challenge is the GFO is the project must be FOM. Need to discuss internally and see if there can be an alternative project with what has been invested? Or wrap it up (terminate)?

Will need to do a Stop Work pretty quick.

Anything we do will be a substantial change which requires going to the Business Meeting.

Suggestions on what will be useful and other possible relocation sites:

- Military site
- High School
- CC has done a CM for a portion of University of California, Santa Barbara that provides a primary sheltering for emergencies; they are a designated site; lots of solar and no energy storage; technically BTM 66 kilovolts (kV) in/12 kV distribution.
- Would this be interesting for the CEC to consider? Will a service territory be allowed?
- University of California, Santa Barbara?
- In discussions with Cal Poly for a similar project as University of California, Santa Barbara
- Working with LA County and all disadvantaged communities; solar microgrid design for three sites in a disadvantaged area which include CCF.
- CC did the FOM Case Study; could take another run at this and do a sequence of webinars that FOM processes need to get fixed. This is 100 percent within scope and TKT.
  - Include RES?
  - There could be limits because GFO-16-309 is TD&D (Technology Demonstration & Deployment)

GFO is TD&D funds: requires 25 percent disadvantaged communities and 10 percent low-income; must be reported. Mike recommends that these funds go into a disadvantaged/low-income communities.

Questions:

1) Any funds due to PG&E or others?

2) What can we do with funds remaining?
3) Wrap up plan? Results in budget and scope change

Partial Stop Work Order allows us to continue to work and get paid for the work we need to do to find a viable solution and/or terminate.

Stop Work Order will take a couple of days to receive and could last about two to three months.

Any written commitments that have been made and paid, will be paid through the grants as long as there is justification.

Whatever we do will requires a Business Meeting.

First next steps:

1) Mike to discuss internally the feedback from SFFD and update CC.

2) Find out what QC's costs are including a battery restocking fee.

3) Determine budget based on two pathways: (1) paper study, (2) termination of project. (CC)

4) If we cannot move forward with the existing VGES site location, can we move forward with the remaining funds via an alternative pathway, i.e., new location, study only?

<u>March-2022 report out to Quenby Lum (CEC CAM) during 3/16/2022 Project Review webcon and recap email from Craig Lewis to Quenby</u>:

SFFD has changed its opinion and recently imposed a 100-foot separation requirement between the VGES BESS and any residential structures. This determination is based on the lithium-ion chemistry of the Sungrow BESS that QC has already ordered. Given that the order is non-refundable, QC is hoping the CEC will be amenable to supporting a new site that QC will secure, potentially at a high school in San Mateo County and within the PG&E service territory.

If the CEC will support a new location, QC would ideally like to interconnect the BESS BTM, because this would result in a streamlined interconnection process and allow for enhanced economics due to tax benefits from tying to BTM solar and SGIP eligibility from a BTM configuration.

In any case, the project team sees three options from here which are as follows:

- Allow QC to site the BESS at a new location, ideally in a BTM configuration.
- Allow the CC to facilitate a new Subcontractor to replace QC. Importantly, the new Subcontractor would need to bring a lithium iron phosphate chemistry that should be able to preempt the SFFD requirement for 100-foot separation. Note that QC has accumulated about $75k of eligible VGES billables, not counting the cost of the BESS which I believe QC could use in a different project if it were to assign VGES to a new Subcontractor. As you might recall, ETB is a viable candidate to serve as the new Subcontractor, because I vetted ETB early last year when seeking a replacement for

Pathion -- and ETB has expressed continued interest in VGES, as recently as a couple months ago.

- Terminate the VGES project altogether.

Follow on call scheduled for 3/17/2022 with Mike Gravely to discuss this matter.

3/4/2022 – call held between the Clean Coalition and Qcells to discuss SFFD Fire Marshall's feedback:

Discussed feedback from SFFD Fire Marshall, alternative solutions, and next steps.

Once UL9540A test report is received from SunGrow, QC will submit to SFFD Fire Marshall an exemption letter requesting the installation of the SunGrow 250kW/556kWH Battery and Inverter System; product model ST556KWH-250UD.

2/28/2022 report out from Qcells:

- Received feedback from the City of San Francisco Fire Inspector that there are concerns with the battery cells' proximity to itself and the surrounding buildings. SFFD requires a 100-foot setback from buildings. This is a setback we're hoping to resolve with references from SunGrow the battery manufacturer.
- Qcells also received support letters from the following entities who support UL9540A test method for evaluating thermal runway fire propagation in battery energy storage systems.
- Qcells requested UL9540A test report from SunGrow.

2/18/2022 Project Review call with Quenby:

Craig provided the update to Quenby on PG&E site visit assessment, proposed options, and QC decision to move forward with Option 2 – relocating the battery to be installed next to the mailboxes which seems to be the most viable pathway for VGES.

Craig also informs Quenby that this is the fourth time PG&E engineering has performed a site visit on the VGES.

Feb-2022:

On 2/11/2022, QC receives from PG&E their feedback based on the 1/27 site visit – feedback is as follows:

- **Upsize Existing Transformer (Option 1) – NOT APPROVED/NOT FEASIBLE:**
    1. The two spare conduits are reserved for the existing panel of the building. If the property owner decides to add loads in the future to max out the capacity of the existing panel, PG&E will install additional service cable by utilizing the two spare conduits. That is why I try to ask the SLD for the building to confirm. I believe the building has a 2000-amp main panel.

2. Per the SLD for the battery system, the requested service is rated at 1000 amps which will need three- to five-inch conduit. Per the Greenbook standard, you can't install more than seven to five-inch conduit on the secondary side.

- **Additional Transformer (Option 2) – proposed location is acceptable to the PG&E engineering team:**
    1. It appears there is adequate space to fit the new pad mounted transformer with all clearances. Your team to provide revised site plan to reflect the proposal.
    2. This trench area is a little bit congested. Your team to survey the area, provide civil plan to show all existing utilities and confirm proposed trench route will satisfy minimum separation to other utilities per Greenbook requirement.
- **Alternative Battery Location (Option 3) - proposed location is also acceptable to the PG&E engineering team:**
    1. You can't use the three spare conduits, same reason like the transformer above.
    2. Although this area is cleaner for trenching, but the nearest tie-in point to the main line is very far. It's over 200 feet. Voltage drop and trench cost for long distance are two major concerns. You may end up to re-pave the entire sidewalk.

Jan-2022:

Site visit conducted on 1/27 for PG&E to evaluate the existing transformer and project location. PG&E initial feedback is that transformers do not have space to be upgraded, additional transformer will be needed in location near resident mailboxes.

Dec-2021 report out to Quenby Lum during 12/17/2021 Project Review webcon:

Craig reported that due to PG&E's lengthy engineering review process, the permission to operate (PTO) target date was pushed by three to four months out to January-February 2023; QC had no choice but to accept schedule but will continue to work with PG&E with accelerating the schedule.

Jul-Nov 2021 Progress Report reported the following:

- Despite several attempts to compress (fast-track) the interconnection timeline, PG&E is unwilling to accelerate its schedule associated with the same issues that PG&E presented in the 2-BESS scenario, including potential transformer upgrade concerns, and pre-parallel testing delays. As such, QC had no real choice but to accept the latest PG&E's SGIA schedule that pushes PTO to Q1-23. Although QC will continue to press PG&E to improve schedule, PG&E's schedule is ultimately out of the control of both QC and the CC. Without PG&E schedule improvement, the VGES PTO-COD (commercial operation date) might require an overall VGES schedule extension.

- During 11/15/2021 Project Review with Quenby Lum (CEC CAM), Craig provides Quenby of the update below from QC; Quenby did not raise any concerns.
- On 11/8/2021, QC reports out to the CC that the Sungrow ST615KWH-250UD BESS was discontinued and will no longer be produced. QC has identified a drop-in Sungrow BESS alternative for VGES. Specifically, QC plans to procure Sungrow's E3 250kw/ 556kWh, which has all necessary VGES functionality. The missing grid-forming capabilities are not a VGES requirement.

Although there are no significant problems to report, a significant change is the 1-BESS WDT Interconnection Application was submitted to PG&E on 5/26/2021. Once the Interconnection Application fees are paid (which must be within 10 business days from receipt of invoice), PG&E will begin their review process. Based on QC's construction schedule it is anticipated that the SGIA will be executed early Oct 2021 (this does not include the Escrow agreement process).

<u>Updates from 5/26/2021 back to 2018</u>:

On 5/26/2021, REP Energy/QC (REP/QC) submitted the 1-BESS Interconnection Application (IA); PG&E acknowledged receipt of the application and invoiced REP/QC the WDT Fast Track fees in the amount of $1,800 (Application fee = $800; Study fee = $1,000). QC confirms this submission is on track with their construction schedule.

On 5/20/2021; QC and Mission Housing executed the Easement Agreement; this agreement ties to site control for the interconnection and permitting process. QC confirms that deliverable meets with their construction schedule.

In February and March 2021, Craig Lewis conducted due diligence to qualify both QC and ETB as qualified New Subcontractors, and Wendy Boyle then joined to help both parties finalize their due diligence processes. The outcome of these negotiations had led to the execution of the QC New Subcontractor Agreement between (execution date 30 April 2021).

On 2/26/2021, PG&E officially terminated the VGES 2-BESS SGIA. This means the New Subcontractor will need to submit a new Interconnection Application for the VGES 1-BESS.

Although Pathion/PG&E have officially terminated the 2-BESS VGES SGIA (effective 2/26/2021), the CC continues to work on its core project deliverables that will bring value to not only the Energy Commission but to the industry; i.e.: FOM Interconnection Case Study (Task 8), Policy innovation (Task 7), and the Utility Business Model (Task 9). We are aiming to present the VGES 2-BESS FOM Interconnection Case Study & Pilot at the CEC-hosted at the June 2021 joint workshop.

On 2/12/2021, PG&E issued an erroneous termination notification of the VGES 2-BESS SGIA based on a misinterpreted email from Jess Turnbull explaining that Pathion was in the process of withdrawing from the VGES project. However, Pathion did not make an official request to terminate the 2-BESS SGIA as the CC was working to secure an Assignee Subcontractor that might want to maintain the 2-BESS, including the associated SGIA that was already in place. This erroneous PG&E action resulted in an immediate escalation directed by Craig Lewis resulting in Pathion successfully requesting PG&E to cancel the erroneous termination process.

On 1/28/2021, David Corzilius sends an email to Pathion, the CC (i.e.: Craig Lewis, Frank Wasko, Wendy Boyle) of his concerns of the two-step process Pathion and the CC are moving forward with and advises he has forwarded the matter onto PG&E Law for further review and guidance. David never advised he would take this action, rather that he would support and work with the team on the next steps.

During the 1/27/2021 follow-on telecon between David Corzilius, Jess Turnbull, and Frank Wasko (Wendy Boyle listened in), an update was given that the Certification of Beneficial Owners is currently in process with NCS, and the Escrow Agreement assignment document is with Pathion; David once again expressed his concern with this process, however, and advised Jess to send an official email notification to East West Bank (EWB) and PG&E Electric Generation Interconnection (EGI) Credit Risk (cc: David) of this matter. Jess follows David's directive and sends email accordingly.

As per Frank's directive to Wendy on 1/21/2021, she is to include David Erne on her follow-up email to Quenby Lum on the status of the budget amendment #5 and No-cost Term Extension 6/30/2022 request as they have not been able to reach Quenby since 1/8/2021; David replies that he has reached to Quenby but has also forwarded our email onto Mike Gravely who has stepped in as David has moved onto the CEC's Supply Analysis Office taking over Fernando's position as he has retired. Frank and Wendy have a call with Mike Gravely on 1/25/2021 and per Mike he can approve the budget amendment, but the No-cost Term Extension must go through a separate internal CEC review/approval process which could take a bit longer.

During the 1/13/2021 Utility Construction Schedule telecon with David Corzilius, discussion was focused on the transfer of ownership of the Escrow account and once approved by PG&E the withdraw of the current SGIA (2-BESS 500 kW/1096 kWh) and resubmission of the new SGIA Interconnection Application (1-BESS 250 kW/548 kWh). Per David's recommendation, Pathion should notify EWB and PG&E EGI Credit Risk immediately advising of this change and request the appropriate documentation; however, David further expressed that he does not understand why we want to move forward with this two-step process versus the Consent of Assignment process. Frank provides David with a brief explanation in that Craig Lewis wishes to take control of the Escrow account based on the options agreement that was executed between Pathion on the CC back on 11/3/2019, and notes that based on previous discussion with David C that this two-step process should only take 4 to 6 weeks versus the Consent of Assignment which can take up to 12 weeks, thus causing further delay with the project. David acknowledges, and Jess Turnbull contacts EWB and receives on 1/22/2021 the Certification of Beneficial Owners form and their Escrow Agreement assignment template. Frank forwards both docs to Craig Lewis for further review and process.

On 1/4/2021, Pathion notifies the CC of their Board's decision to withdraw from the VGES project which is due to the financial constraints of the organization. Frank Wasko takes immediate action by notifying Craig Lewis and Quenby Lum; calls are setup between Pathion (including their legal counsel) and Quenby for the same week.

- Bonnie Lind also notifies David Corzilius of this change on 1/7/2021 and requests a telecon. Telecon with David held on 1/13/2021 (standing Utility Construction Schedule monthly telecon); David provides his recommendation to Jess Turnbull to contact EWB immediately to obtain the appropriate forms.

- At this time, there are no changes to the budget amendment #5 and No-cost Term Extension of 6/30/2022 and no changes to moving forward with the 1-BESS 250 kW/548 kWh.

On 1/4/2021, Bonnie Lind notifies Frank Wasko of Pathion's decision to withdraw from the VGES project. This decision is a directive from Pathion's Board and is primarily as a results of the financial constraints Pathion is experiencing. A telecon is held on 1/7/2021 with Bonnie Lind, Wallace Glusi (Pathion attorney), Craig Lewis, Frank Wasko and Wendy Boyle (who was optional, but attended) to discuss the next steps and if Pathion will continue to support the CC during this transition and through March 2021. Bonnie Lind and Wallace agree; Pathion's Subcontractor Agreement is amended and executed extending their performance end date to 3/31/2021. On 1/8/2021, Frank and Wendy held a telecon with Quenby Lum advising her of Pathion's transition and to discuss next steps. Quenby agrees to stop the current budget amendment and No-cost Term Extension; agrees submitting a new budget amendment with all new changes is the best course of action. However, Quenby did advise that she will need to update David Erne of this change; but does not anticipate any issues as the CEC continues to support VGES.

During the check-in with Quenby on 12/21/2020, due to the CEC's new internal review/ approval process along with the Christmas holiday, this has caused a delay with being able to obtain the approval for the budget amendment and No-cost Terms Extension of 6/30/2022.

Due to the Christmas holiday and scheduled vacations, David Corzilius cancelled the 12/16/2020 Utility Construction Schedule meeting; updates to the project were exchanged via email and sidebar telecons between Pathion (Bonnie Lind) and David Corzilius.

On 11/4/2020, David Corzilius advised that PG&E is still 100 percent on board with moving forward with the 1-BESS 250 kW/548 kWh system sizing, but it is taking longer than originally expected to receive EGI planning services results. Again, the delays are due to COVID-19 and the public safety power shutoff (PSPS) outages.

On 10/8/2020, David Corzilius advised that PG&E should have their results the following week (week of 10/12/2020). Continued follow up emails were sent to David inquiring on status with continued clarification being requested by PG&E on the 1-BESS 250 kW/548 kWh proposed solution. On 10/26/2020, Bonnie Lind reached out to David Corzilius to obtain a status update; on 10/30/2020 Frank Wasko also followed up as no response had been received from David; same day David responded apologizing for the delay and that EGI is reviewing, and the results should be received early next week (week of 11/3). Bonnie and Frank spoke with David who conveyed that the delays are due to the PSPS events, wildfires, and COVID-19. The delay with being able to obtain PG&E's results on the proposed solution is impacting the CC's, Pathion's, and REP's ability to finalize the budget amendment.

Due to the PSPS events and wildfires, Quinn Nakayama had to reschedule the 9/22 telecon to discuss the VGES project and the proposed 1-BESS 250 kW/548 kWh solution to 10/15/2020.

This delay impacted our ability to move forward with the budget amendment as PG&E's results will let us know whether the recloser and vault will still be required for this proposed solution.

During the 8/12/2020 PG&E Utility Construction telecon, the proposed solution of downsizing the system was discussed with David Corzilius; however, David advised that since VGES is under the FastTrack program any revisions would require a restart of the PG&E interconnection application/SGIA process; matter has been escalated to PG&E leadership for further review and further investigation of any possible exceptions as to avoid further delay with the project.

Between 8/12/2020 and 8/31/2020, Frank Wasko and Quinn Nakayama exchanged text messages regarding VGES and the proposed solution; however, due to PG&E's heightened PSPS activity, Quinn advised that he will be unable to have a deep discussion until early Sep-2020.

On 7/15/2020, CPUC approved FERC 841 which allows California ISO to lower the minimum capacity requirements for energy storage resources to provide ancillary services from 500 kW to 100 kW, this change allows the CC, Pathion and REP to re-evaluate a proposed solution of reducing the ES system configuration from two units to one unit which still meets all requirements as fore mentioned This change goes into effect on 10/1/2020 for New Generation Program applications.

On 6/30/2020, Ella Samonsky (City Planner) informed Pathion, REP, and the CC that she was going on Leave effective 7/1/2020. There was no prior notification from Ella, thus this announcement seemed either last minute or lack of communication from Ella. Alex Westoff is the new City Planner assigned to VGES. However, per Alex, he needs at least two weeks to review the entire conditional use authorization (CUA) package. This last-minute communication and change in assigned personnel from the San Francisco Planning Department, has resulted in further delays in the construction schedule, pushes out our target of a July 2020 Planning Commission hearing, and causes further delay with being able to obtain permits allowing construction to commence.

Due to COVID-19 and the recent civil unrest, the construction schedule has been delayed including a halt to all non-essential activities within the Planning Department and Planning Commission.

The lack of transparency and poor communication from Ella Samonsky to REP Energy has caused delays in the permitting/planning process; Ella advised it will only take her two weeks to complete her review of the CUA upon receipt of the documents; we are now in week six due to her continued questions including questions that have been asked and answered multiple time now.

REP and Pathion were unaware that Valencia Gardens were under a PUD; Joel Ware (REP), Frank Wasko, and Bob O'Hagan met with Moses Corette on 1/23/2020 to review the permit package again and discuss next steps as the Zoning Administrator could not approve the application as it must go through the Planning Commission due to PUD.

Due to PG&E's requirement of relocating its secondary transformer out into the public right-away (installed in an underground vault), the City of SFFD requirement to install a chain-link security fence due to safety and security purposes, and the City of San Francisco's requirement to hire Union labor, the VGES project budget has increased by approximately $288,000. Although there is potential savings from Pathion's new battery costs as well as other potential savings resulting from the battery saving and the fact there is no PG&E DERMS, these savings will not cover the additional construction costs. Thus, the CC budget amendment will include a request for additional Energy Commission grant funds.

Due to COVID-19, the PG&E Innovation Group have had to refocus their efforts on adjusting the new work environment and preparation plans for the upcoming wildfire season. Thus, our PG&E Technical Advisory Committee (TAC) Tiger Team efforts of reviewing and discussing telemetry and constrained interconnection, resilience, and hosting capacity and interconnection have been delayed.

The lack of transparency and visibility into California ISO protocol changes impact the California ISO interconnection process; discontinuation of California ISO's ISP Dispersive communications has resulted in the CAISO VGES interconnection missing the February Network Model Build which pushes the California ISO interconnection to be in the June 2020 timeframe.

PG&E final engineering cost estimates delayed again due to PSPS – was due 10/31/2019, revised to 11/8/2019, finally received on 11/22/2019; final engineering design also show extensive changes, thus require a complete redesign of Pathion/REP's initially approved engineering construction drawings.

REP's redesign of the construction drawings delayed due to the end of the year holiday schedules and pre-scheduled vacations.

PG&E initial engineering sketch received on 9/20/2019; final approved engineering sketch received on 11/18/2019; final sketch shows radical changes from the 9/20/2019 sketch which accounts for the secondary transformer location out into the public right-away and unground installation as well as increased cost to the project. But PG&E is sensitive to the project cost, has kept the SGIA utility equipment upgrade cost down - $170,000 ($3,763 less that initial estimate).

The significant delays with PG&E's interconnection application process continue to cause an impact to the schedule – specifically to Task 4, 5, and 6. But, continued efforts by all parties are ongoing to ensure project stays on track; and we continue to work in parallel on these tasks where we can including continuing to work in parallel on Tasks 7, 8, and 9, Task 11, and Task 1 general project tasks reports that require content from Tasks 4 through 9, and Task 11 (i.e., Final Report Outline, etc.).

Significant problems:

PG&E would not allow us to maintain the existing SGIA and downsize the system from a 2-BESS 500 kW/1096 kWh to a 1-BESS 250 kW/556 kWh, even though any grid impact would simply be reduced. Thus, as stated above, on 2/26/2021 PG&E terminated the VGES 2-BESS SGIA and QC had to submit a New Interconnection Application for the VGES 1-BESS 250 kW/556 kWh project.

On 7/15/2020, CC Policy team learned that in response to FERC 841, California ISO has lowered the minimum capacity requirements for energy storage resources to provide ancillary services from 500 kW to 100 kW. This goes into effect on 10/1/2020 for New Generation Program applications. CC, Pathion and REP verified that this change offers a proposed solution to downsize the VGES energy storage system from two units to one; the team verified that downsizing to one ES meets all requirements: (1) CEC increased 25 percent hosting capacity, (2) the California ISO 100 kW of energy storage resources, (3) PUD maximum 100 sq. ft. (square foot) footprint (proposed solution is 85 sq. ft. footprint), (4) PG&E's safety and reliability requirements, (5) proposed solution is contained in one space versus two separate locations (original site plan), and (6) proposed solution maintains the project budget. Further verification and validation to be conducted between CC, Pathion, REP, and PG&E to verify proposed solution and to determine if the following other PG&E requirements can be eliminated due to downsizing to one ES (thus, additional potential savings): (a) is the SCADA recloser still required, and (b) is the relocation of the secondary transformer (installed in underground vault) still required due to ES may be in one location. The proposed solution also allows the ES system to be located in one location, thus meets the PUD maximum 100 sq. ft. footprint; proposed solution is a maximum of 85 sq. ft. footprint.

On 6/30/2020, Ella Samonsky informs REP, Pathion, and CC that she will be on Leave effective 7/1/2020. There was no prior notification from Ella on her status change. This continued lack of transparency within the Planning Department has resulted in further delays to the Planning Commission hearing targeted for Jul-2020 and the construction schedule (i.e.: being able to obtain permits).

On 5/11/2020, Ella Samonsky notified REP, Pathion and the CC that the CUA documents will not satisfy the actual PUD amendment (as per the PUD); specifically, the electrical yard drawing that was part of the CUA application. This drawing needs to be updated to reference the changes (i.e.: callouts) including provide clarification if there will be any impact/changes to the trash/recycle location within this site location. Ella clearly noted in her communication that there was a miscommunication/lack of communication by Planning on this matter.

COVID-19 and the recent civil unrest has caused significant delays with the construction schedule, permitting process, and delivery of equipment into the States and onsite.

Per Ella Samonsky's email dated 5/17/2020 the actual PUD must be amended to reflect the proposed PUD design changes. REP followed the instructions as noted in the application. This new/required step was never communicated to REP Energy.

The notification Pathion received from the California ISO on 2/3/2020 on the discontinuation of the California ISO's ISP Dispersive communication is problematic and challenging due to the lack of transparency and visibility into their process and the lack of good communication from the California ISO.

Upon resubmission of the permit package on 1/22/2020, REP informed by Moses Corette with SF Planning Department that the Valencia Gardens apartment complex is under a PUD which requires CUA submission amending the existing PUD to approve the installation of any additional structures (i.e., energy storage installations must be within the 100 square-foot threshold; VGES system footprint exceeds this allowable threshold) which now must be reviewed and approved by the SF Planning Commission:

- This regulation pushes the construction completion out to Jun-Jul 2020 timeframe and PTO/COD out to around Aug-Sept 2020 timeframe; this delay impacts our ability to collect the ES system's performance utility data during the summer months. The full summer months of data collection is key to the Task 5, Scheduled Allocation Optimization Report.

Delay with receiving from PG&E the final approved engineering sketch delayed the submission of the permit package; originally 7/21/2019 (Jun-2019 construction schedule), revised to 11/1/2019 (Oct. 2019 construction schedule), revised to 12/6/2019 (Nov. 2019 construction schedule; NOW 12/13/2019 (as of 12/4/2019); additionally, the relocating of the secondary transformer out into the public right-away could still pose challenges to the project once we break ground.

Delays with receiving PG&E's final engineering cost estimates and final engineering drawing has pushed the project schedule out significantly; initial PTO/COD based on SGIA was a date range between 11/22/2019 to 1/3/2020; changed to 2/14/2020 now 3/24/2020.

During the 11/22/2019 pre-con meeting, David asked the question if SFPUC has any oversight on the VGES site. Pathion needs to investigate further.

PSPS continue to cause delays with the construction schedule including PG&E being able to finalize the final engineering cost estimates which was due by 10/31/2019, then 11/8/2019, received on 11/22/2019.

Although, we have received a 6/30/2021 term extension, and we anticipate that this extension and the anticipated PTO/COD date of 3/24/2020 will allow for ample performance system data collection needed for Task 6 through Task 11 deliverables, any further construction delays will impact the schedule as well as providing quality reporting.

Pathion unable to move forward with ordering the switchboard, the redesign of the permit drawing and permit package submission until they receive the final cost estimates. However, Pathion received design approval from PG&E on 8/16/2019 and a copy of the approved engineering sketch on 9/20/2019 allowing Pathion/REP to move forward. CC issued a letter to Pathion advising potential breaches to the contract. Telecon discussions held between Craig Lewis, Mike Liddle, Bonnie Lind and Frank Wasko to discuss the delays, and find an agreeable solution. Agreement between parties initiated and both parties are moving forward with the project.

On 9/18/2019, David Corzilius confirmed with the PG&E Service Planning that the engineering cost estimates, and design have not started yet.

PG&E missed the 8/8/2019 and 8/28/2019 final engineering cost estimates and design due dates; additionally, PG&E Service Planning assigned a 3rd Independent Professional Engineer (IPE) thus causing further delay in the schedule as this person needed to come up to speed on the project as well as issues within the process.

PG&E's previously assigned IPE's final engineering cost estimates and design due date of 8/8/2019 was incorrect; per new IPE this was a mistake made by the previous IPE as the correct date is 8/28/2019. However, PG&E IPE missed the 8/28/2019 revised date as well; thus, adding further delay to the construction and overall project schedule.

PATHION/REP/REP submitted the disconnect switchgear to PG&E back in Oct-2018 and re-submitted to PG&E on 3/20/2019 at the request of PG&E. PG&E Metering approved the equipment on 4/24/2019; however, this is pending final approval from the PG&E IPE. Since the switchgear is a longer lead item, it is our hope that the approval would be confirmed on 8/8/2019 when the PG&E's engineering cost estimates process is completed and received.

PG&E's utility construction schedule is still not acceptable and impacts the overall project schedule.

PG&E's IPE group's final estimated PTO/COD is scheduled for 11/22/2019 to 1/3/2020*. Nonetheless, we continue to work in parallel on Task 7, 8, and 9.

Due to PTO/COD 11/22/2019 to 1/3/2020 and the current project end date of 6/30/2020, Task 1 (Final Report products), 7, 8, and 9 product deliverables are at risk of meeting the September/November 2019 CEC deadlines as these two factors do not allow enough time for system performance testing/data collection and any other results from Task 4, Task 5, and Task 6.

PG&E IPE group was not assigned until 3/8/2019, thus delayed the utility construction kick-off meeting.

PG&E IPE did not attend the 6/19 field site visit which was to help her move forward with PG&E's engineering cost estimates analysis.

Per the SGIA, Pathion cannot begin their part of the construction build until PG&E has completed their site preparation. Pathion was anticipating working in parallel of PG&E, however, they must comply with the SGIA Terms & Conditions as these comply with PG&E's safety regulations.

Any form of CEC extension (beyond the current project end date) will allow additional critical data to be obtained, evaluated, processed, and included in the final report and key technical product deliverables.

During the core TAC meeting with PG&E we addressed/identified a number of items that will prove a challenge. One of the most significant is that the previous DERMS projects were built as one-off systems and are now dismantled so there isn't a pre-set platform for the ESS to be able to start interacting with. One of the major new goals and challenges will be to identify and then connect with the real time operations. We addressed and agreed to form subcommittee tiger teams to address telemetry challenges and solutions as well as hosting capacity and resilience.

Task Deliverables Evidence of Progress:

Task 1: 56 percent of the product deliverables are 100 percent complete; completed products include but not limited to TAC advisor board members list/confirmed participation including

TAC core team confirmed participation; TAC meetings held to date (kick-off held on 3/22/2019; Follow-on core TAC meeting held 4/24/2019, TAC tiger team meetings held on 7/10/2019, 7/12/2019, 10/3/2019, 10/8/2019, and 10/8/2020; TAC meeting summaries submitted to CEC via the October 2020 Progress Report (presentation included as separate email attachment to Oct 2020 PR); Final TAC Schedule; completion of three CPR meetings (attendance and product deliverables submissions); 54 monthly pre-submission invoice packets (electronic), 42 monthly invoice packet submissions (hard copies and final electronic versions); 1st No-cost 12-month term extension approved by CEC – revised performance project end date now 6/30/2021; 2nd No-cost 12-month term extension and budget amendment submitted to the CEC on 11/30/2020.

Task 2: 100 percent complete.
Task 3: 100 percent complete.
Task 4: 70 percent complete:

- On 2/12/2021, Certification of Beneficial Owners form submitted to Pathion.
- On 1/30/2021, Craig Lewis executes the Escrow account Certification of Beneficial Owners form.
- On 10/15/2020, SF Planning Commission voted to approve our full-sized ESS (500 kW/ 1096 kWh) footprint. A conditional use authorization was issued with no expiration date. As discussed, we can install a single 250kw inverter and 548kWh ESS now and then bring it to full size later when desired.
- On 10/8/2020, VGES TAC Utility Business Meeting was held to discuss the project and the path forward with downsizing to the 1-BESS 250 kW/548 kWh proposed system solution.
- On 9/25/2020, Quinn Nakayama confirms telecon to discuss the VGES project current design and the proposed downsizing solution; call set for 10/8/2020.
- On 9/15/2020, City Planner confirms the Planning Commission hearing is set for 10/15/2020; required posters hung onsite on 9/24/2020.
- On 7/28/2020 Pathion received confirmation from the California ISO that the interconnection amendment submitted in June 2020 for the revised interconnection and COD date had been accepted.
- Updated electrical yard drawing with the additional information requested by Ella Samonsky, submitted to Ella on 6/23/2020. This information is needed for the PUD amendment.
- On 5/11/2020, REP Energy submitted updated site plans to Ella Samonsky (City Planner) and provided responses to her site questions.
- On 4/21/2020, REP Energy provides Ella with the actual plan set depicting the required information she needs relative to the site location.

- On 3/23/2020, Richard Sucre (City of San Francisco, Principal Planner) assigns Ella Samonsky (San Francisco City Planner) to the CUA. Richard advises Ella will need two weeks to review the initial documentations.
- REP submitted Priority Processing Application and Planning Commission pre-approved on 2/24/2020; CUA and current drawing submitted to Planning Commission on 2/25/2020.
- REP received switchgear on 2/19/2020.
- Onsite meeting confirmed with Sam Moss and Alex Lantsberg to provide project updates and discuss lease agreement amendment.
- New Resource Implementation application submitted to the California ISO 2/3/2020 Pathion anticipates submitting Bucket 1 and 2 materials in Sep. 2020 to be part of the September load study. the California ISO COD is now scheduled for Dec. 2020.
- Telecon held 1/30/2020 with Liz Watty, Deputy Director with Planning Dept to discuss process for submitting Priority Processing Application as permit package must be approved by the Planning Commission due to the PUD.
- Meeting held on 1/28/2020 between SF Planning Department Planner and the President and Vice President with the Planning Commission in an effort to obtain their sign-off to help clear the way for a consent agenda authorizing VGES' existing design configuration (two batteries/two inverters) thus eliminating the need for a CUA amending the existing PUD or a redesign to one battery/one inverter which will stop the project.
- Meeting held on 1/24/2020 between SF Planning Department and Zoning Administrator to review permit package and the proposed solutions.
- Meeting held 1/23/2020 between CC, REP, and SF Planning Department Planner to further discuss VGES and importance of the project.
- 1/22/2020, REP resubmits permit package (which includes suggested changes from Fire) on 1/22/2020 including renderings required by Zoning Administrator; REP informed by Moses Corette with SF Planning Department that the Valencia Gardens apartment complex is under a PUD which requires CUA submission amending the existing PUD to approve the installation of any additional structures (i.e.: energy storage installations must be within the 100 sq. ft. threshold; VGES system footprint exceeds this allowable threshold) which now must be reviewed and approved by the SF Planning Commission.
- REP meets with SF Permit Office (Fire, Building, Electrical, Mechanical, Public Works) on 12/26/2019 to being the permit process; Building, Electrical and Mechanical reviewed and approved the engineering construction drawings over the counter; Public Works advised that there is no need for a variance or permits to install the transformer vault and trenching in the sidewalk as the sidewalk is on private property; SF Fire

reviewed, overall design was approved, but requested some additional notes to be added.

- REP received switchboard order confirmation from vendor (WESCO) on 12/6/2019; eta of delivery to site 2/10/2020.
- PG&E final engineering cost estimates received on 11/22/2019; final approved engineering sketch received on 11/18/2019.
- REP placed switchboard PO with WESCO (vendor) on 11/19/2019.
- REP moved forward with the electrical and civil engineering redesigns (permit package preparation).
- REP confirmed its Materials & Miscellaneous project budget on 11/22/2019.
- REP Energy prepared the PO for the switchgear and that order will be completed in early July 2019.
- PG&E Metering approved disconnect switchgear submittal on 4/24/2019; waiting final approval from IPE.
- PG&E utility construction schedule kick-off meeting held 3/27/2019.
- PG&E monthly utility construction schedule meetings began on 4/23/2019.
- Financial security posting completed 12/19/2018.
- Executed escrow agreement received 11/26/2018.
- Escrow account setup completed 11/16/2018.
- Executed SGIA received 10/26/2018.
- Long-lead item equipment purchased on 12/5/2017.
- Task 4.1.1 Site Preparation: Equipment and Site Installation Remediation Plan completed and submitted to CEC.

Task 7: 50 percent complete:

- Draft Regulatory Advancement Report is 80 percent complete; to be submitted to the CEC late July 2020/early Aug. 2020.

Task 8: 57 percent complete:

- Draft-final FOM Interconnection Case Study with Pilot submitted on 3/22/2021.
- Draft FOM Interconnection Case Study submitted on 3/4/2021.
- Draft Storage Interconnection Recommendations Report submitted on 9/26/2019.
- Draft FOM Interconnection Case Study 90 percent complete.

Task 11: 50 percent complete:

- High quality digital photograph submitted on 5/8/2018.
- Draft Initial Fact Sheet submitted on 8/9/2018 (before the 4/16/2019 CEC deadline).
- NWA, Avoided DER, and 25 MW PV Fact Sheets submitted on 11/1/2018. (Note: these deliverables were developed for CEC, but are not in the approved SOW)
- Final Initial Fact Sheet submitted on 5/29/2019.
- Draft Technology/Knowledge Transfer Plan submitted on 9/20/2019.

Significant problems or changes (historical): The section only includes the most recent activities in comparison to our plan:

PG&E would not allow us to maintain the existing SGIA and downsize the system from a 2-BESS 500 kW/1096 kWh to a 1-BESS 250 kW/556 kWh. Thus, as stated above, on 2/26/2021 PG&E issued the official written VGES 2-BESS SGIA termination notification; thus, Pathion's replacement New subcontractor will need to submit a New Interconnection Application for the VGES 1-BESS 250 kW/556 kWh project. However, once PG&E has reconciled the VGES 2-BESS Escrow account and notifies Pathion, Pathion will immediately notify the CC which will then specify the party who the Escrow account is to be assigned to.

As stated above, on 1/28/2021, David Corzilius sends an email to Pathion, the CC (i.e.: Craig Lewis, Frank Wasko, Wendy Boyle) of his concerns of the two-step process Pathion and the CC are moving forward with and advises he has forwarded the matter onto PG&E Law for further review and guidance. David never advised he would take this action, rather he will support and work with the team on the next steps. This action has resulted in the matter being Escalated to PG&E, Pathion, and CC leadership; call scheduled between Quinn Nakayama, Craig Lewis (CC), and Frank Wasko to discuss further and to find an expedient resolution/solution to this matter.

On 1/4/2021, Pathion notifies the CC of their Board's decision to withdraw from the VGES project which is due to the financial constraints of the organization. Frank Wasko takes immediate action by notifying Craig Lewis and Quenby Lum; calls are setup between Pathion (including their legal counsel) and Quenby for the same week.

- Bonnie Lind also notifies David Corzilius of this change on 1/7/2021 and requests a telecon. Telecon with David held on 1/13/2021 (standing Utility Construction Schedule monthly telecon); David provides his recommendation to Jess Turnbull to contact EWB immediately to obtain the appropriate forms.
- At this time, there are no changes to the budget amendment #5 and No-cost Term Extension of 6/30/2022 and no changes to the moving forward with the 1-BESS 250 kW/548 kWh.