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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Microgrids Pursuant to Senate Bill 1339 and Resiliency Strategies.	Rulemaking 19-09-009

MOTION OF PACIFIC GAS AND ELECTRIC COMPANY (U 39 E) TO FILE SUPPLEMENTAL REPORT AND TO EXCEED PAGE LIMIT SET FORTH IN ASSIGNED COMMISSIONER AND ADMINISTRATIVE LAW JUDGE'S RULING

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Dated: September 25, 2020

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Pursuant to Rule 11.1 of the California Public Utilities Commission's (Commission) Rules of Practice and Procedure, Pacific Gas and Electric Company (PG&E) moves to submit a supplemental report into the record of this proceeding and to exceed the page limit set forth in the *Assigned Commission and Administrative Law Judge's Ruling Seeking Comment on Policy Questions and an Interim Approach for Minimizing Emissions from Generation During Transmission Outages*, filed in this proceeding on September 4, 2020 (the "ALJ Ruling").

The ALJ Ruling directed that opening comments in response to the ALJ Ruling must not exceed 30 pages.[1] The ALJ Ruling also directed that any such opening comments must be filed by no later than September 18, 2020.[2] By an e-mail Ruling issued by ALJ Colin Rizzo on September 10, 2020, the deadline for filing opening comments on the ALJ Ruling was moved to September 25, 2020.

Concurrently with the filing of this Motion, PG&E is filing opening comments on the ALJ Ruling that are within the 30-page limit. Through this Motion, PG&E seeks to supplement the record of this proceeding with the report provided as Appendix 1 to this Motion (the "ADL Report"). That report is entitled "An Economic, Technical, and Environmental Analysis of Diesel Alternatives to Mitigating the Impact of Public Safety Power Shutoffs on PG&E

[1] ALJ Ruling, p. 9 (Ordering Paragraph (OP) 3).

[2] *Id.*

Customers," and it was prepared by ADL Ventures, an expert third-party consulting firm, under contract to PG&E.

The ADL Report, in combination with PG&E's separately-filed opening comments, exceeds the 30-page limit established in the ALJ Ruling. Nonetheless, PG&E offers the ADL Report into the record of this proceeding as it believes that the ADL Report provides significant additional analysis and information that is directly responsive to the ALJ Ruling's general policy question regarding alternative resource cost-effectiveness and reliability.[3] Specifically, the ADL Report examines the current state of the art with regard to over a dozen alternative resources to diesel generation that might be employed to enable cleaner microgrids for PSPS resilience, discusses the feasibility of those alternatives from technical, economic, and environmental lenses, and identifies gaps and opportunities to be addressed in order to increase the feasibility of these alternative solutions.

The ADL Report does not identify definitive solutions or "winners," nor is it a procurement evaluation protocol. However, it provides a useful framework and data as inputs into the ongoing discussion about how best to identify and support viable alternatives to diesel generation over the long-term. PG&E offers the ADL Report into the record at this time in order to allow parties the opportunity to comment on the methodologies and data it presents as part of their reply comments on the ALJ Ruling, so that the Commission can consider the ADL Report when adopting an approach for minimizing emissions from generation during transmission outages, and so that PG&E can benefit from all stakeholders' input on the general framework as PG&E develops its proposal for a long-term procurement framework as envisioned by the ALJ Ruling.

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[3] ALJ Ruling, pp. 3-4 (Question 2 of Section 2.1.1).

For the foregoing reasons, PG&E requests that the Commission waive in this instance the 30-page limit on comments imposed by the ALJ Ruling and that it accept the ADL Report into the record.

Respectfully Submitted,

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Dated: September 25, 2020

APPENDIX 1

An Economic, Technical, and Environmental Analysis of Diesel Alternatives to Mitigating the Impact of Public Safety Power Shutoffs on PG&E Customers

DISCUSSION DRAFT: September 25, 2020

Authors:
Chris Richardson
Jeff McAulay
Ben Silton
Henry Meyer
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Executive Summary

This is a hard problem to solve.

Public Safety Power Shutoff (PSPS) is a tool to prevent catastrophic wildfires, but it creates other problems for customers.

In 2020, PG&E has used temporary generation to provide power to "safe-to-energize" customers. Whenever transmission lines are de-energized to reduce wildfire ignition risk, PG&E can keep the lights on for customers that would have otherwise been cut off from power by placing generation at the substations that serve those customers.

While PG&E seeks to reduce the scope, scale, and duration of PSPS events to limit the customer impact, it is deploying mobile diesel generators - the only solution that fully met the requirements of its all-source RFO - for temporary generation in 2020. Moving forward, PG&E is committed to exploring wires and non-wires alternatives to diesel generation.

In this report, ADL Ventures (ADL) evaluates 15 clean and clean*er* non-wires alternatives to diesel from economic, technical, and environmental perspectives.

Evaluation Approach

Economic considerations may be the most complex and least understood of the three evaluation categories: economic, technical, and environmental. An economic analysis must attempt to wrestle with and normalize different ownership structures, contractual terms as well as PSPS event frequency, duration, and location. We do not know in advance how many PSPS events will happen or which substations will be affected. We do not even know if the substations identified for PSPS mitigation in 2020 will be the most critical substations to energize moving forward. Adding to the complexity, many solutions - especially those that are mobile - could create additional value outside of PSPS events such as outage support, but these are difficult to predict and quantify.

To evaluate the economic tradeoffs, we first establish a Diesel Economic Indifference Price based on published costs of $182/kW-year for equipment + $0.30/kWh for fuel (plus labor, which is assumed to be roughly equal across technologies). We compare the Diesel Economic Indifference Price, adjusted for capacity and de-rate factors, against a project developer's estimated 5-year economics in the absence of PSPS mitigation adders[1]. Several technologies could shift from out-of-the-money to in-the-money if PG&E were to subsidize project development with funds or a "PSPS adder" valued up to the Diesel Economic Indifference Price, adjusted for capacity and de-rate factors.

In our analysis, behind-the-meter technology options may require lower PSPS adders (if any) to incentivize a project to be developed, in large part because 1) certain BTM technologies such as solar

[1] These estimates are proposed as an initial benchmark. They can only be validated by actual vendor quotes that factor in nuances of specific geographic, market, and financial conditions.

and storage have quickly come down the cost curve and 2) under current NEM tariffs, BTM technologies compete against retail rates[2], which are much higher than LMP rates, up to the level of the customer load.

Of course, **kilowatt-hours are not fungible**. In addition to varying economic returns, we also must consider the differences among solutions from technical and environmental perspectives.

While diesel has the negative externalities of CO_2, NOx, CO, PM, and SO_2 emissions as well as noise pollution, its technical advantages that include black start, power density, mobility, and inertia support cannot be discounted. Even natural gas options can encounter challenges related to load block or load rejection such that the system may need to be oversized to maintain frequency and voltage. Besides turbines and reciprocating engines, few clean alternatives can provide the spinning mass required to maintain inertia. Further, diesel and natural gas have uniquely high power densities, or the ability to sustain, for instance, a 30MW substation in a 50' x 50' footprint. Finally, diesel has long been a common form of backup generation and diesel-based equipment has become easy to transport, widely commercially available, and safe to operate.

Technology Evaluation and Key Trade-offs

Three key observations emerge from the economic analysis:

1) **Only technologies with turbines or reciprocating engines that utilize a diesel-based or natural gas-based form factor fuel could be standalone solutions**
2) Technology combinations including cleaner generation, renewables, and behind the meter solutions can incrementally reduce the need for diesel and natural gas generators over time but appear to require significant additional investment in communication, control, and grid infrastructure to contribute reliably at scale.
3) The more revenue streams a technology can earn, the more attractive the non-PSPS economics can be, decreasing the PSPS adder that may be required to bring a solution in-the-money. Value stacking is essential but complex and difficult to determine to what extent and how quickly supplemental revenue sources (such as RA) will be available. Of course, the availability of these additional revenue streams must be balanced against potentially high costs of distribution, transmission, or substation upgrades.

Because substation footprints are typically small (rarely more than 100' x 100'), we must either identify clean, power-dense solutions or eliminate the constraint of space at the substation to move beyond fossil-based generators.

Cleaner, power-dense solutions at the substation are available today, but not always at a competitive price. At least in the near-term, we will likely need a turbine or reciprocating engine or turbine at the substation to provide an unusual grid service: *temporary, load-following power in a distribution-only grid*. Reciprocating engines or turbines could be fueled by HVO, natural gas, renewable natural gas (RNG), brown hydrogen, or green hydrogen. The viability of clean drop-in fuels such as HVO, RNG, and green hydrogen can be limited by feedstock availability and logistical challenges. Still, the gating concern for

[2] Residential retail rates are modeled using the E-TOU-C tariff while C&I is modeled using the B-10 tariff.

cleaner fuels is economics. On the one hand, the capital cost of reciprocating engines and turbines is so high and allocated over so few days per year of PSPS events[3] that fuel cost can represent a relatively small share of total cost. On the other hand, many alternative fuels and storage mediums are meaningfully more expensive than fossil-based fuels, e.g., the cost of green hydrogen today is >10X that of natural gas for equivalent energy potential.

The effective price per ton of carbon abated by shifting from diesel to renewable natural gas (RNG) exclusively during PSPS events is high at roughly $1,000/ton CO_2. Some other technologies are higher still. If CO_2 were the only driver of a shift away from diesel, PG&E could instead consider other investments (or even carbon offsets) that could have a better environmental return on investment if deemed acceptable by the community.

While fuel-switching to cleaner fuels during PSPS is hard to justify from its cost of carbon alone, PSPS adders to a developer of cleaner generation or storage assets can be a valuable investment if those adders can lead toward low-carbon solutions *year-round*.

Diesel's particulate matter (PM) emissions, not CO_2 emissions, are responsible for the highest societal cost (or negative externality). A more accurate environmental comparison of any particular technology solution against diesel is based on the societal cost of emissions, a metric that weights the impact of PM, CO_2, NOx, and SO_2. The sooner the shift from diesel the better, as local health benefits compound over time for every year diesel is displaced.

Fuels like green hydrogen could experience similar cost reductions as have been observed in solar and lithium-ion batteries, but the time horizon for significant cost reductions is likely beyond the 3-5 year scope of this analysis. Further, considerable infrastructure investments would be required at each substation for safely storing fuels like hydrogen, which corrode pipes and require cryogenic tanks for a liquefied fuel or large caverns for gaseous fuel.

Fortunately, most natural gas generators can be transitioned to RNG or hydrogen with a relatively small incremental investment of as little as 5% of capital cost. Hydrogen can be blended with natural gas in increasing amounts over time (to a certain extent) and RNG can be blended into the gas pipeline system. If those energy sources come down the cost curve faster than anticipated, PG&E can accelerate the transition to cleaner fuel sources.

One solution must be load reduction during PSPS. PG&E has gone from one end of the spectrum in 2018 - full power outages during PSPS - to a scenario in 2020 in which ratepayers located within load pockets powered by diesel generators may not even know that their power is costing PG&E an order of magnitude more than it did the day before. Therefore, it is in the best interest of ratepayers writ large for demand to be reduced during PSPS events.

By launching temporary microgrids to light up "Main Street," PG&E addresses this by determining critical loads and energizing small city centers. For load pockets that will be energized in full, **PG&E**

[3] We assume 8 days/year in most of our analyses

should look for ways to curtail non-critical loads or shift load from peaks. Approaches could include residential thermostat programs, mandates to curtail non-critical load enforced by advanced metering, or C&I demand response (DR) programs. C&I DR programs would be most effective if structured for each substation's unique need, e.g., black start or location-specific peak, but this tailored approach is likely prohibitively expensive. A more straightforward structure such as a time-of-use (TOU) C&I DR incentive during a PSPS could also be considered. Such a program would be simpler to design, but less targeted and potentially difficult to manage with small numbers of participating customers in each load pocket.

Existing TOU energy rates are unlikely to change behavior in a PSPS event. However, any effort to raise TOU rates significantly during a PSPS event is likely to be economically regressive and politically unpalatable. Incentive payments are more likely to be effective than temporary PSPS rate hikes.

Another solution is potentially more palatable given the "new normal" that has emerged with Covid-19. We have learned that most office buildings are indeed not critical, and many workers can be just as productive at home, provided they have electric power. Even in a post-Covid world (should that come to pass), a mandate or incentive structure could be established to temporarily but entirely shut down non-critical commercial buildings during PSPS events without causing undue economic disruption.

Another alternative to clean, power-dense solutions at the substation is to think differently about space.

First, we can get more out of the substation footprint by thinking creatively about using it. For example, solar arrays could potentially cover a large portion of a substation's footprint (say 400' x 400') rather than just space currently assumed as available for generation, if elevated by 20'. While solar may provide less than 1MW of capacity covering a given substation and would need to be tested for the ability to withstand seismic events, this resource helps reduce net load and reinforces a message that PG&E cares about clean energy. Other cleaner generation or storage sources, such as large batteries or fuel cells, could potentially be stacked vertically to get more power out of the existing substation footprint if allowable by transmission line and distribution circuit configurations.

Getting more power out of the substation footprint is one thing, but the real opportunity comes from thinking beyond the substation. **If parking lots, rooftops, and garages throughout the load pocket become grid assets, power density no longer becomes the gating constraint**. If 1) the non-trivial challenges of integrating a high-penetration of distributed energy resources (DERs) into a distribution-only grid can be overcome and 2) if the T&D upgrade investment required to power the load pocket in a distributed manner is not prohibitive, then PG&E will be able to more confidently and cleanly energize the load pocket during PSPS events while also increasing the resilience of the grid throughout the year.

Particularly given the increased electrification of transportation, new opportunities will arise to leverage cars, buses, trucks, and trains for grid flexibility during PSPS and throughout the year. While California is projected to have 2.5M electric vehicles by 2025 (and >1M in PG&E's territory), there are uncertainties related to using electric cars as grid assets during emergencies. Not only are many OEMs averse to enabling bi-directional flow in EVs, but consumers' willingness to discharge their vehicles during an emergency to support the grid has not been tested. Other transportation options negotiated through businesses or local governments may be more predictable assets. PG&E incentives to support electric buses could not only increase electrification year-round, but those buses could also provide critical grid services during PSPS events. PG&E could also lead the way by electrifying its own fleet and utilizing that fleet's battery storage during PSPS events.

Certain technologies such as woody biomass do not initially appear to be economical in our analysis of the five-year adder that a developer would require for a profitable project. Still, positive externalities and non-market forces could make them viable. Most biomass plants are in the Sierra Nevada Conservatory, and some of the at-risk substations are in areas with significant biomass feedstocks. While the variable OpEx of running a biomass plant typically exceeds LMP prices, BioMAT tariffs at a PPA price of ~$0.20/kWh can help make projects very profitable to a developer, albeit at the expense of PG&E ratepayers. The use of biomass for power generation can solve two problems concurrently: biomass can power the distribution grid during PSPS events while also providing a use for small diameter wood that can effectively act as kindling for wildfires. There is even a third bonus benefit in the case of biomass for remote grids where problematic wires could be made redundant by islanded, remote generation. While biomass does have negative emissions externalities (NOx and SO_2 in particular) and emissions from trucking of the feedstock to the plant, these impacts can be dwarfed by the vegetation management benefits of removing small-diameter wood from the forest.

Under the current NEM tariff structure, behind-the-meter solar wins on cost by a wide margin, in part due to a cost-shift from NEM customers to the rest of the rate base, but it poses technical challenges, particularly around intermittency, inertia, and fault current. Moreover, the recent wildfire-related ash and smoke blocking the sun in California has highlighted risks that solar may significantly underperform while wildfires burn. Other technologies such as flywheels and batteries compensate for technical difficulties while being more expensive individual resources on a dollars-per-kWh basis. For solar + storage to function as grid assets during PSPS, an additional incentive for PSPS participation may be required. Additionally, the deployment of a DERMS and other technologies to improve the integration of DERs into the grid will be required.

Technology "Teams" and Loading Order

Given that cleaner alternatives to diesel all have trade-offs from economic, technical, and environmental perspectives, we must layer in different combinations of technologies ("teams") that can compensate for the shortcomings of individual technologies.

As outlined below, technology teams can be layered in sequentially, prioritizing cleaner and lower-cost options. This framework broadly aligns with the CPUC Integrated Resource Planning guidelines for loading order, which "mandates that energy efficiency and demand response be pursued (procured) first, followed by renewables and lastly clean-fossil generation."

0. Do No Harm: Ensure that older residential solar installations can be curtailed, if necessary, if generation in the load pocket exceeds demand.

1. Reduce Net Load by Encouraging Islanding: Support and encourage islanded BTM solar+storage wherever possible. While these assets may not actively provide flexibility to the grid, they reduce the net load by allowing customers to island without relying as much on the grid during PSPS.

2a. Leverage Available BTM DERs as Grid Assets: For BTM assets with smart inverters, leverage over-built assets to support the grid by exporting power from locations throughout the load pocket (this layer requires a DERMS and other enabling technology).

2b. Deploy Clean IFOM Solutions (layers 2a and 2b are interchangeable in terms of priority): Complement some permanent assets such as solar arrays with other clean mobile solutions at or near the substation. Critically, enough space must be reserved at the substation for turbines or reciprocating engines (layer 3a) to provide enough power to serve the remaining load, at least in the near-term.

3a. Deploy Dirtier IFOM Solutions: Natural gas turbines or HVO reciprocating engines may be the most logical near-term replacements for diesel, with natural gas being particularly attractive when gas transmission pipelines are within 1,000 feet. Capital equipment can be modified at a relatively low cost to support other fuels such as RNG or hydrogen as they come down in cost.

3b. Leverage Grid Services Assets: Grid resources such as demand response, flywheels, batteries, or even diesel locomotives must be layered in to ensure stable distribution grids and provide peak shaving, black start, inertia, etc.

Critical Gaps

Particularly for BTM DERs, the critical gaps inhibiting the use of cleaner technology assets are not the generation and storage technologies themselves but rather technology demonstration, policy & incentives, and grid infrastructure.

Organizational and Operational

- Pilots and Demonstration: PG&E has significant resource constraints that limit its ability to pilot a multitude of promising technologies. For any of the solutions proposed in this document to be deployed, PG&E must access a dedicated set of technical personnel and equipment to pilot promising technical solutions.

Policy and Incentives

- Utility Incentive Structures: Utilities lack financial incentives to promote BTM generation and storage on equal footing with IFOM generation.

- Demand Side Management: There is neither a mandate nor an incentive for customers to curtail or shift loads during PSPS.
    - Demand Response: There is currently no DR program unique to PSPS events.
    - Commercial Baseload Reduction: Non-critical office buildings are not incentivized or mandated to reduce or eliminate load during PSPS (an aggressive but potentially feasible suggestion).
- DER Incentives: Customers with BTM batteries or other DERs are not currently incentivized to operate their storage devices any differently during a PSPS event than at any other time.

Grid Infrastructure

- Inverters Incapable of Curtailing: Many inverters installed before 2018 can do more harm than good to the grid during critical events like PSPS, particularly with high DER penetration.
- PSPS Signaling: DERs cannot currently receive a signal informing them whether the system is in PSPS (or about to be in PSPS).
- DERMS: PG&E does not currently have a full-fledged DERMS, which is necessary for connectivity, grouping, and management of DERs in a PSPS event or any outage.
- Communications: Common DER and demand response communications methods, e.g., internet or cell phone towers, may not function in an emergency. A different way of communicating with DERs and demand response assets would be required.

Developer Support

- Ease of Pursuing Private Developments: Private developers face an uncertain path to deployment, given poor visibility into potential LMP and RA revenues and a lengthy and potentially costly interconnection process.
- Land Use Permitting: Projects - especially those with large footprints or externalities - can have difficulty getting approvals for permanent siting.

Next Steps

This analysis is in no way prescriptive. A future effort should leverage this analysis to craft a 3-5 year strategy to mitigate the impact of PSPS events. That strategy will likely hinge on resolving the critical gaps identified in this report.

Other next steps should include the development of a model to analyze technology combinations as “teams” and an effort to quantify the option value of mobility and other technology attributes.

Background and Problem Statement

PG&E has established PSPS protocols to de-energize at-risk lines during dry, high-wind conditions to reduce wildfire risk. PG&E leadership aims to sufficiently harden the grid such that PSPS events become unnecessary. In the meantime, PG&E is making PSPS events more targeted by adding 600+ switches to de-energize smaller parts of the grid. It is exploring novel technologies to near-instantaneously de-energize fallen lines to prevent fires from starting in the first place due to fallen trees. Through better weather modeling and vegetation management analytics, PG&E has shortened the expected duration of PSPS events to 1-2 days or less and is working aggressively to reduce the scope, scale, and duration of PSPS events in the future. Nonetheless, PSPS events will likely remain a necessary tool to combat catastrophic wildfires in the near- and medium-terms.

Despite its environmental drawbacks, diesel was the only commercially-available and scalable solution that fully met the requirements of PG&E's all-source RFO. To the extent supply is available, PG&E utilizes renewable diesel alternatives (HVO) as a fuel source for those generators. In 2020, most diesel generation will be sited at substations seasonally, but other generators will be sited in a hub-and-spoke fashion to serve nearby substations just-in-time.

While this solution is effective from a technical standpoint - diesel is power-dense, load-following, mobile, ramps quickly, and meets frequency requirements - it remains relatively expensive at over $182/kW-year + fuel and not preferred from an environmental perspective. Diesel generators emit almost one ton of CO_2 per MWh, which is undoubtedly high, but the most significant environmental impact is from nearly half a pound of particulate emissions per MWh.

Given that backdrop, PG&E seeks diesel alternatives to provide resilience to its customer base at the lowest cost and with the lowest environmental impact. Given that no individual solution outperforms in all three categories (economic, technical, and environmental), trade-offs must be carefully considered when selecting an individual or combination of technologies.

While in-front-of-meter (IFOM) solutions can be connected to a Pre-installed Installation Hub (PIH) at pre-determined substations - or, in some cases, in a temporary microgrid with a PIH on "Main Street" - PG&E is also interested in understanding options to leverage BTM assets.

Alternative technologies to diesel come in the following forms: base generation at substations, BTM generation & storage, IFOM generation & storage, or load control / demand response. Given the urgency of the challenge, PG&E prefers to focus on technologies that could be ready to pilot in the next 1-2 years, such that a solution would be ready for full-scale deployment in 3-5 years or less. PG&E may be willing to financially support the advancement of clean and cleaner earlier-stage technologies that can contribute to addressing this challenge through funds that were set aside by the wildfire settlement to promote clean energy.

Generation and storage technology advancement alone is necessary, but not sufficient. Equally or even more important is removing barriers from policy, business model, and grid infrastructure perspectives.

This techno-economic analysis focuses on identifying gaps and opportunities in technological solutions but will stop short of proposing full solutions.

High-Level Evaluation Approach

ADL analyzed 15 alternatives to diesel, as referenced below. Most of the technologies modeled were assumed to be mobile, or at least seasonal, technologies located at or adjacent to the substation. We also assessed BTM generation and storage technologies that could support a load pocket as a distributed network.

Technology/Approach	Mobile IFOM	Stationary IFOM	BTM	Grid Services*
Diesel (as reference)	✓			
Natural Gas (turbine + recip engine)	✓			
Renewable Diesel	✓			
RNG (turbine + recip engine)	✓			
Combustible Hydrogen	✓			
Linear Generator	✓	✓		
Flywheel	✓	✓		✓
Solar	✓	✓	✓	
Solar + Storage	✓	✓	✓	✓
Biomass	✓	✓		
Electric Vehicles			✓	✓
Electric Buses/Trucks	✓		✓	✓
Batteries	✓	✓	✓	✓
Long-duration storage	✓	✓		
Fuel Cells	✓	✓	✓	
Demand response				✓

* Grid Services = services to ensure the stability of the distribution grid, particularly to complement non-fossil generation. Grid services include peak shaving, voltage support, and frequency support

Single Technology Evaluation

If any single alternative to diesel were to adequately address the economic, technical, and environmental requirements, this analysis might not warrant continued research and exploration. Instead, each technology offers a unique set of benefits and limitations, warranting additional consideration as to how to leverage the benefits of individual technologies while covering for (or reducing) their limitations.

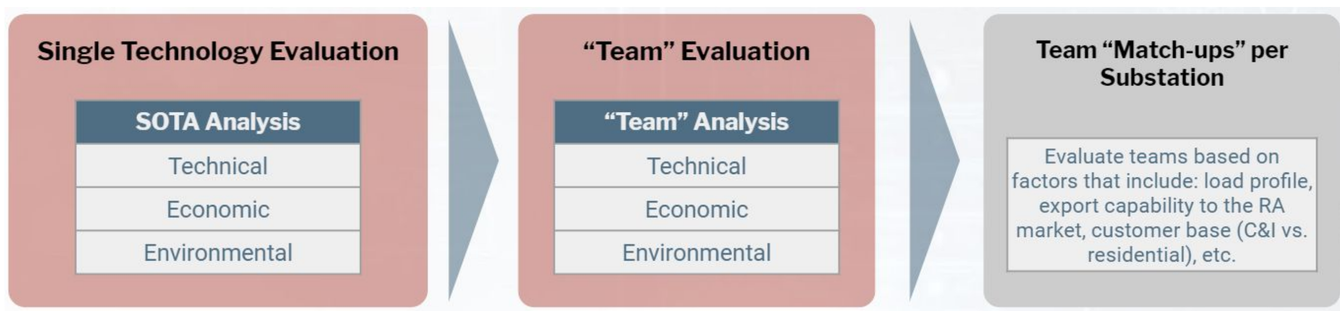
This report stops at a single technology analysis, but a natural next step would be to extend the study to evaluate teams of technologies and match said teams up against substations, as described below.

“Team” Evaluation

Different technologies can play complementary roles and could theoretically be layered in combinations that we refer to as “teams.” For example, if we designate BTM solar + storage as “temporary baseload,” after grid infrastructure and policy gaps are resolved, the team would require spinning mass from flywheels, turbines, or reciprocating engines as well as a complementary solution for shaving evening peaks. For example, a battery-electric bus (BEB) fleet plugged into a bi-directional charging station could also lower the head of the “duck curve.”

Further, a team optimized for one load pocket may not work for all load pockets. For example, woody biomass may be an elegant solution for some substations near BioMAT plants, but transportation costs would make it impractical elsewhere. Or, one substation may have a high penetration of solar within its load pocket without corresponding storage, causing a recurring sharp peak in the early evening. In such a case, it may be particularly critical for temporary storage technologies like lithium-ion batteries to shave peaks and reduce the required base generation capacity. Another crucial factor is the revenue potential for each technology outside of PSPS; for example, from bidding into RA markets where available. That availability is driven by location-specific transmission capacity constraints that can preclude access to wholesale markets.

While this analysis stops at a "single technology evaluation," a full process flow that could ultimately be followed is outlined visually below.



Economic, Technical, and Environmental Evaluation Approach

Evaluation Approach: Economics

Diesel Economic Indifference Price

While the current contractual structure need not guide future willingness-to-pay, it can be instructive to evaluate diesel alternatives relative to that reference price. In the August 25 CPUC workshop, the assumed cost for diesel is $210 to $500 per kW-year. Assuming a 450 MW procurement per year (consistent with the 2020 procurement), PG&E may spend $94M to $225M per year or $940M to $2.25B over a 10-year time horizon. The cost could be higher still in the absence of mobile solutions to serve multiple substations. This all-in cost could be one way to benchmark the budget for diesel alternatives, adjusted upward to account for negative externalities of particulate and CO_2 emissions.

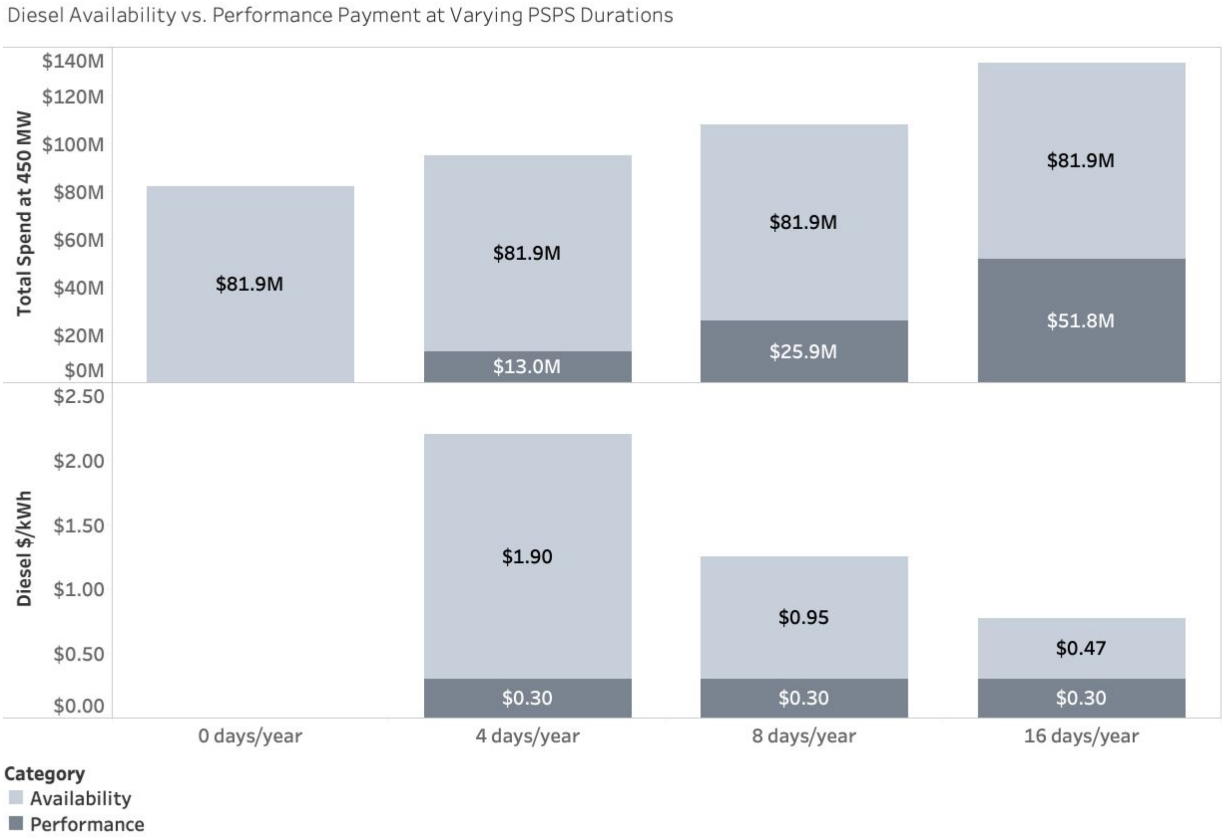
Any number of factors might affect the long-term cost to PG&E if it were to continue with the 2020 status quo. For example, grid hardening over the next ten years and shorter, more targeted events may reduce the need for PSPS mitigation after five years. Conversely, PG&E may need to energize more substations more frequently over time if the wildfire season continues to get longer and more intense.

How might we compare the indifference price for cleaner technology alternatives to diesel? Some clean technologies may have lower year-round capacity factors in general (e.g., solar) and may not be as readily available throughout a 1-2-day PSPS event (e.g., a 4-hour lithium-ion battery alone is unlikely to participate in a 2-day PSPS event for more than eight total hours). Therefore, the indifference price for any individual technology must be adjusted based on these capacity and de-rate factors.

In addition to an estimated $0.30/kWh in fuel cost[4], per published figures, PG&E currently pays approximately $182/kW-year (or $26/kW-month over seven months) as an availability payment (also referred to as a reservation cost) for the diesel assets. This payment for the diesel reference case serves as the benchmark for the diesel-equivalent value per kW (adjusted for capacity and de-rate factors) of the 15 different technologies normalized as a lease rate to PG&E for their use during wildfire season. **We refer to this as the Diesel Economic Indifference Price**. **This indifference price is not necessarily PG&E's willingness-to-pay, but rather a useful baseline metric against which we can compare other single technology options.**

Assuming eight days per year of expected PSPS usage, the cost of temporary, leased diesel generation is $1.25/kWh. Over 75% of that cost comes from a fixed availability payment (reservation cost), and the balance comes from fuel payments.

[4] Based on California's diesel price in 2020 and EIA diesel gen average heat rate value.



Project Developer Directional 5-year Economics

This analysis's primary cost metric is the delta between this maximum Diesel Economic Indifference Price and a private developer's estimated gross margin in the absence of a PSPS adder paid from PG&E to the developer. In other words, the estimated PSPS adder is calculated as the net financial support needed to make projects financially viable. That adder is compared against what PG&E is already paying for diesel.

A robust analysis of a developer's economics would require a project-specific financial model, complete with debt-to-equity ratios, developer-specific IRR requirements, and tax equity levers outside the scope of this analysis. Short of that rigor, ADL proposes a simplified but level evaluation of each modeled technology that estimates the five-year directional economics for a developer[5], inclusive of:

- Capital cost for five years of a given asset's lifetime;
- Any required distribution grid upgrade costs;

[5] This structure is founded on multiple hypotheticals, including financial mechanics and a five-year timeline. These are not absolutes and are likely to vary by technology, vendor, and even substation; rather, they are intended as simplifying assumptions in order to attempt an apples-to-apples assessment across scenarios.

- 10% required rate of return on depreciated CapEx; and
- Five years of OpEx netted against revenue a given project could expect to receive from energy markets (Locational Marginal Price or LMP revenue) for IFOM assets and retail rate bill savings, TOU rate arbitrage, and/or demand response (BIP) revenue for BTM assets.

Similarly, a robust analysis of PG&E's true costs of enabling new capacity should include project-specific T&D system upgrades. We omit these costs as they are contextual and location-dependent. Though BTM and substation-sited projects would likely require fewer grid upgrades on average than offsite IFOM projects, any systematic cost adjustments could be considered false precision and are therefore not included in our techno-economic analysis.

We also have excluded Resource Adequacy (RA) values from our base assumptions, in part because of the relatively low deliverability of Distributed Generation for RA revenue in many of the substations selected for PSPS mitigation. Transmission congestion significantly limits deliverability. RA revenue could and should be modeled in an analysis at the substation level.

A precise location-specific analysis should also include assumptions for permitting costs, distribution upgrades, and other necessary equipment if it is determined that there is an apples-to-apples method of applying these project-specific factors.

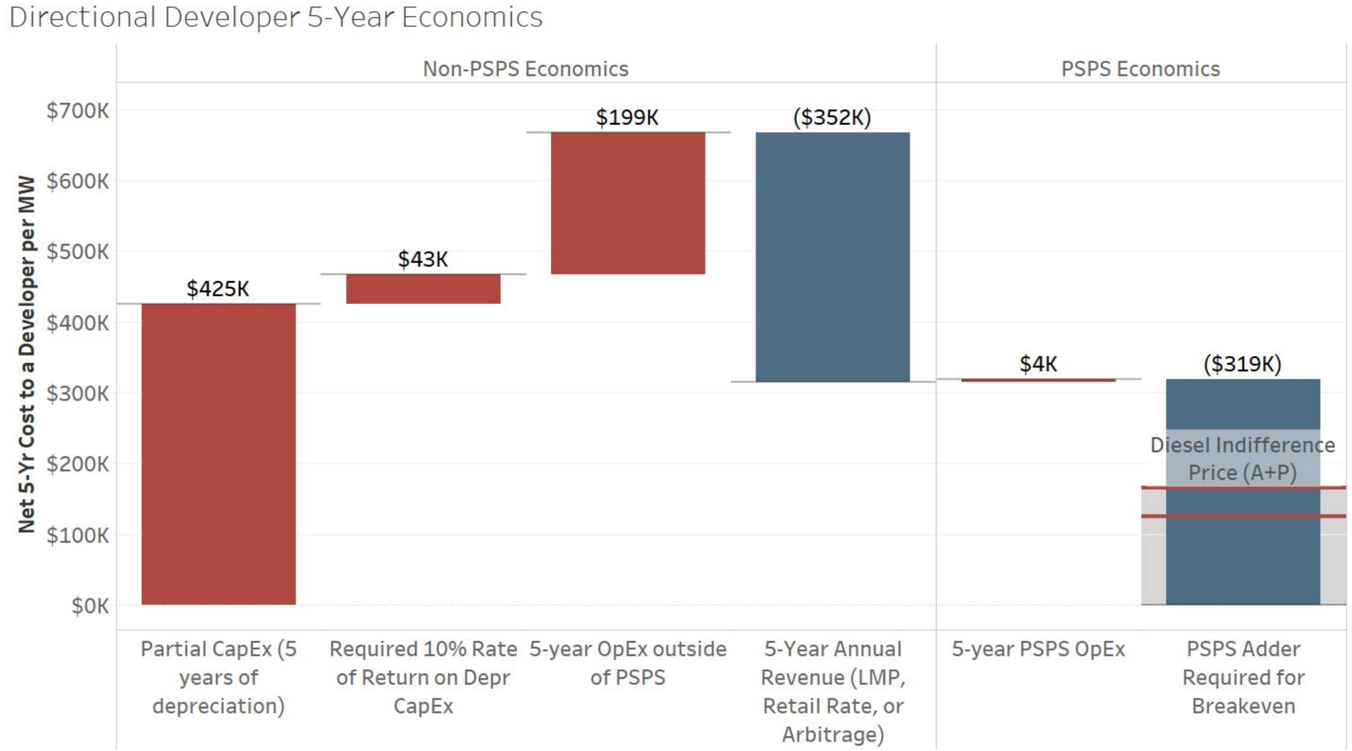
We chose five years as the economic evaluation period because it is at the high end of acceptability for PG&E's contractual term and at the low-end of acceptability from a project developer's perspective to develop a project that would not otherwise be profitable in the absence of a PSPS adder. Further, it is consistent with the current five-year incentive timeline of the Self-Generation Incentive Program (SGIP).

The biggest question we address with the project developer analysis is: are the economics of a given non-diesel technology attractive enough that a project would be profitable if PG&E were to pay a developer up to the Diesel Economic Indifference Price?

The answer to this question can help inform whether each technology is likely to perform well in an RFP process. **If a project is still not profitable even after receiving adders up to the Diesel Economic Indifference Price, its other benefits, e.g., environmental benefits or grid services, would have to be sufficient to overcome the higher cost. However, suppose PSPS Adders up to the Diesel Economic Indifference Price would make a project "in-the-money" (or make an already profitable project even more profitable). In that case, those incentives are more likely to support technologies that provide long-term value.**

Representative Example

Here we walk through a representative example of a front-of-the-meter technology that receives LMP energy payments outside of PSPS events.



The anticipated capital cost is approximately $2,550 per kW. A straight-line depreciation over 30 years leads to an allocated 5-year cost of $425K per MW. We assume a 10% required rate of return of $43K per MW and five years of OpEx of $199K. This OpEx is netted against $352K in energy payments over five years. The result is an estimated net cost to the developer of $323K per MW over five years.

At present, this project is out-of-the-money. It costs more to build than it provides in revenue or avoided costs. This is where a PSPS incentive can bring the project in-the-money. Assuming $4K of incremental OpEx during a PSPS event, PG&E would have to pay roughly $319K per MW (a PSPS Adder) to the developer for the project to become profitable.

Is this a good deal for PG&E or not? By comparing $319K per MW to the Diesel Economic Indifference Price, adjusted for PSPS-Capacity Factor, we discover that this is a higher-cost single technology option to PG&E than diesel rentals. For availability payments alone, the diesel-equivalent MW would be $125K over five years. If we include eight days per year of performance payments for the diesel rentals, the indifference price would be $165K per MW over five years (the Diesel Economic Indifference Price represented by the red line). While the modeled adder is higher than the Diesel Economic Indifference Price, it could still be worth it to PG&E and the community if the technology provides environmental benefits or provides complementary grid services (e.g., inertia, frequency) that could enable higher penetrations of DERs within the distribution load pocket.

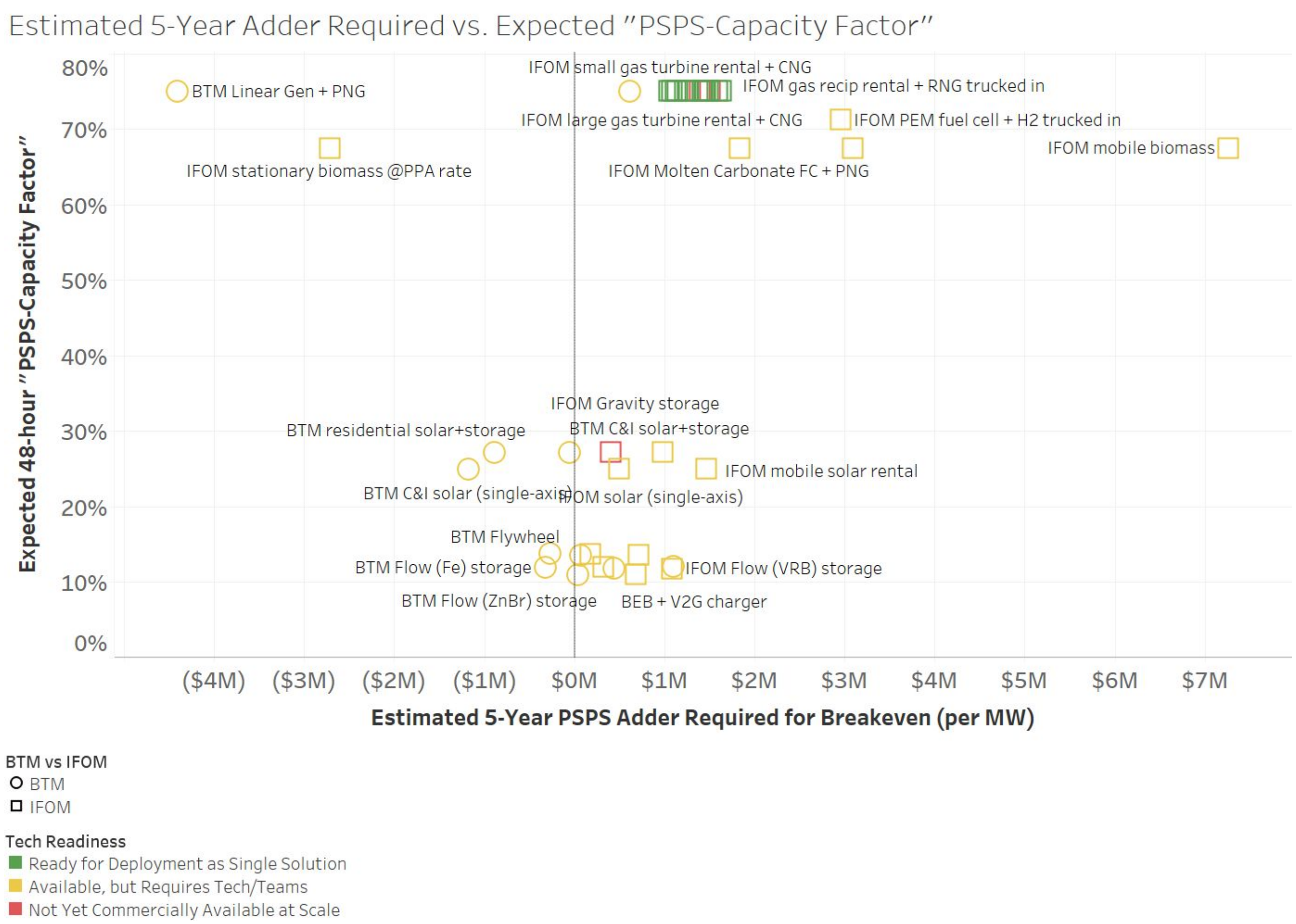
While we haven't modeled other revenue streams such as RA in the single technology model, it could be analyzed at the substation level. For cases in which RA is unavailable - which is likely to be many of the substations in question - the delta between the PSPS Adder with and without RA could be compared against corresponding required transmission upgrades.

Comparative Economics

We compare the 5-year estimated PSPS Adder required for breakeven against the anticipated "PSPS-Capacity Factor" for each technology in the scatterplot below. ADL defines a PSPS-Capacity Factor as the ratio of a technology's expected power output during a 48h PSPS event to its nameplate power capacity. Factors that affect technologies' expected PSPS power output include technology efficiency, operation and maintenance interruptions, and engineering design for accommodating unexpected load spikes. The chart highlights the obvious influence of PSPS-Capacity Factor on the economic evaluation on a dollars-per-MW basis.

There is a wide range of technological and commercial readiness of these solutions (color-coded in the plot). We have categorized the estimated economics of key technologies into three categories:

1. *Ready for deployment (Green)*: In general, **only diesel and natural gas generators could be deployed as standalone solutions at scale for the 2021 wildfire season** if contracts were executed today. RNG and HVO can be included as modifiers in this category, presuming sufficient supply can be procured.
2. *Available, but requires complementary technologies or teams (Yellow)*: **Most technologies evaluated fall into this category, e.g., they have been validated in live customer applications but would require complementary technologies to be a comprehensive solution.**
3. *Not yet commercially viable at scale (Red)*: A few technologies evaluated have not yet demonstrated commercial viability at scale. These include gravity storage and other long-term storage, which are promising and expected to be deployed in the field in the next 1-2 years.



A few observations can be made from the chart. First, there is a cluster of green technologies of roughly similar costs and roughly similar PSPS-Capacity Factors. These green data points represent technologies ready for deployment as single solutions, specifically diesel and natural gas turbines and reciprocating engines. The technology in red represents a solution that has significant commercial potential but is not yet commercially viable at scale, i.e. PG&E cannot feasibly procure several gravity storage units for the 2021 wildfire season.

The vast majority of technologies evaluated are in yellow, representing solutions that are available for deployment but cannot standalone. They must be complemented with other technologies or additional grid infrastructure investments to utilize them as a PSPS solution at scale. For example, a large lithium-ion battery could be combined with a natural gas turbine rental at the substation, but lithium-ion batteries are currently impractical as a standalone solution. A few of the solutions categorized as "Available but Requires Tech/Teams" in yellow have high PSPS-Capacity Factors and low costs (top left), such as linear generators or stationary biomass when subsidized at a PPA rate.

Other solutions in the bottom left would only be used for a few hours per day during PSPS, but appear to be inexpensive options as part of a team.

There are three key implications of this analysis:

1) **Only technologies with turbines or reciprocating engines that utilize a diesel-based or natural gas-based form factor fuel could be standalone solutions**
2) **Technology combinations, including cleaner generation, renewables, and BTM resources, can incrementally reduce the need for diesel and natural gas generators over time** but may require significant additional investment in communication, control, and grid infrastructure to contribute reliably at scale.
3) **The more revenue streams a technology can earn, the more attractive the non-PSPS economics can be**, decreasing the PSPS adder that may be required to bring a solution in-the-money. Value stacking is essential, but it is complex and difficult to predict to what extent and how quickly supplemental revenue sources (such as RA) will be available. The availability of these additional revenue streams must be balanced against potentially high costs of distribution, transmission, or substation upgrades.

The analysis also shows that behind-the-meter solutions (circles) typically appear much cheaper than those in front of the meter (squares). This is primarily due to this economic analysis being a narrow assessment of what incremental program costs are necessary for the solution to break even with the default solution from the perspective of the developer, rather than a full assessment of the underlying costs and benefits of the solution to California's energy system. Due to BTM projects receiving the bulk of their revenue from avoided retail rates via NEM, other customers still bear a significant portion of the costs, albeit less transparently than they would for IFOM solutions.

According to the Draft NEM 2.0 Lookback Study by Itron and Verdant Associates, "The NEM 2.0 program may result in an increase in rates for ratepayers….Residential customers that install customer-sited renewable resources, on average, pay lower bills than the utility's cost to serve them." Per the draft report, every dollar of bill savings to PG&E residential NEM 2.0 customers results in 62 cents of increased rates to other customers.

Given that budgets are not unlimited, **it may make the most sense for PG&E to incentivize customer acquisitions of BTM assets within certain load pockets that are unsafe to energize during PSPS, as distribution-level de-energization will likely occur more often than transmission-level de-energization.** This approach helps first provide customers with backup power when they otherwise would have none, instead of simply reducing the cost of keeping their lights on during PSPS events.

Alternate visualization

The estimated PSPS adder required per MW (blue bar) is also compared against the Diesel Economic Indifference Price (red line) in an alternate visualization below. The Diesel Economic Indifference Price varies for each technology based on the PSPS-Capacity Factor for each technology. For example, the Diesel Economic Indifference Price of a resource with a capacity factor that matched diesel, e.g., HVO, would have a red bar (Diesel Economic Indifference Price) equal to that of diesel. Conversely, a resource such as a lithium-ion battery would be compared against a lower Diesel Economic Indifference Price to account for its lower PSPS-Capacity Factor of 14%.

Estimated PSPS Adders Required Per MW for Breakeven vs. Diesel (5-Yr Timeline)

Option Value

This problem has inherent uncertainty driven by a combination of factors that determine the need to call a PSPS event, such as precipitation and wind speeds. As such, there are risks of (1) over-procurement and (2) stranded assets. **Over-procurement would occur if too much capacity were to be reserved, e.g., 450 MW of mobile generators are reserved for a hypothetical full season, but no more than 300 MW are ever needed coincidentally. Further, stranded assets can become liabilities if multi-year contracts are signed for generation support at substations that become no longer at risk for PSPS events due to system hardening or, for example, unusually wet or calm years.**

The lesson from most real option value analyses is that "options always have value," and in a PSPS context, the option value is the degree to which these risks are mitigated. One key area of uncertainty is geographic, e.g., the number of substations that must be energized concurrently to minimize the impact of PSPS events. It is impossible to predict coincident fire risk across all substations before a PSPS season given natural meteorological uncertainty, and hub-and-spoke mobile options mitigate this risk to a large extent by adding geographic flexibility. **Another area of uncertainty is time-based**, e.g., the number of years for which generation or storage is required at any particular substation.

In the former case, mobile options provide much more flexibility to serve multiple substations concurrently than stationary options. In the latter case, **short-term contracts can help mitigate the risk of stranded assets** should individual substations be sufficiently hardened, making PSPS events obsolete. Stranded assets are not limited to generation assets themselves: **substations typically require millions of dollars of upgrade costs to accommodate and interconnect large-capacity permanent generation equipment, in some locations even 100X more than make-ready costs for temporary interconnection**.[6] Such significant investments merit careful analysis relative to alternative uses of such capital, such as developing systems to unlock the use of distributed resources during PSPS events.

Of course, mitigating these risks comes at a price. Vendors will - and should - demand more favorable terms for shorter-term contracts, while mobile options typically require additional resources for storage, dispatch, transport, and interconnection, often on short notice. Therefore, PG&E's best interest is to develop some qualification AND quantification of such option value and risk-adjust expected costs and benefits accordingly in contract negotiations.

Examples of approaches that could increase option value include:

- *Mobile generation can be used across multiple substations*, reducing the total CapEx required (even if logistics costs increase). The value of mobility in 2020 could be considered as a ~2x multiplier, as ~450 MW of mobile generation were reserved for ~950 MW of aggregate peak capacity. While it remains to be seen whether this level proves sufficient, or too little, or even excessive for the 2020 season, such an analysis should be re-visited each year based on meteorological projections, system hardening progress, and evolving technological capabilities.
- *Shorter contractual terms*, particularly for dirtier fuels, can help PG&E avoid locking in suboptimal environmental options. While diesel generator rentals are available for single seasons, most developers will require longer-term contracts or repurposing agreements if new asset investment is needed.
- *Trucked-in CNG* can obviate the need for natural gas line extensions, even if it comes at a higher variable cost, avoiding future maintenance and land use needs.
- *Smaller assets can allow PG&E to scale up gradually*. For example, GE's TM2500 gas turbine has a relatively low cost per MW but has a minimum capacity of 34 MW. Conversely, Enchanted Rock's gas reciprocating engines can be as small as 400kW.
- *Carbon-neutral and low-variable-cost options - BTM or IFOM - can potentially be used beneficially throughout the year*, not just during PSPS events. For example, solar + storage projects are unlikely to become stranded assets and are critical for achieving PG&E's sustainability goals

[6] Conversation with PG&E.

and mission during PSPS events and throughout the year. Support in the form of a "PSPS adder" would not create stranded assets any more than existing RA and capacity markets.
- *Options to make non-fossil generation viable* - Technologies that can shave peaks and provide grid services in the event of high DER penetrations can increase the *options available to PG&E for integrating intermittent or asynchronous generation sources.* Typically this responsibility falls on CAISO, but if PG&E is responsible for distribution-level management during PSPS events, it is recommended that PG&E and CAISO seek a working partnership to integrate PSPS value in its grid integration planning, modeling, and evaluation.

Finally, option value should be considered when mitigating technology risk - that is, the likelihood that a given technology may fail to perform to its stated responsibility or specs. Even diesel is not perfect, and newer technologies that remain to be proven in a similar use case pose a greater risk. As such, PG&E could consider exploring contract structures to minimize this risk, similar to any of the following:

- Signing a one-season agreement with a guaranteed conversion to multi-year terms upon demonstrated success.
- Testing promising but unproven technologies with multiple vendors to optimize future competency. This may require additional overhead, but lessen the risk of failure.
- Piloting promising but higher-risk technologies at few and/or small substations while over-procuring, to a small extent, mobile diesel generators as a dispatchable backup solution.

To RFP or Not to RFP?

Given that these costs are estimates based on both publicly-available data and estimates provided by vendors, these breakeven "requirements" are only an approximation of what PG&E would expect to see in an RFP. Rather than an end-all-be-all, these results should be viewed as a directional guide to the technologies that could be economically efficient.

Armed with this information, PG&E should feel more comfortable prioritizing in-the-money technologies in an RFP solicitation, as those technologies are more likely to be successful technology "team members."

Technologies are not fungible.

We fully recognize that the analysis above assumes that all kilowatts are created equal after adjusting for capacity and de-rate factors. This assumption is a known simplification. Before any particular technology would be encouraged for an RFP, other factors certainly must be considered.

First, resilience should be given priority over cost. Upholding PG&E's primary goal of providing reliable and safe energy should be a prerequisite for any technology considered. As such, the ability to provide superior resilience should command value in itself.

Next, peak power is typically valued more highly than baseload or intermittent power. Peak power is most likely still more valuable than baseload during PSPS, but that delta may be less than anticipated. The reason for this is that any number of technologies - e.g., batteries, flywheels, demand response -

can be used to shave peak load to an extent. **It is challenging to identify two-day baseload power options outside of reciprocating engines, turbines, or fuel cells during PSPS events. Given this unique circumstance, baseload power may be particularly valuable.**

The other areas that will impact any particular technology's value are technical and economic, as described below. From an environmental perspective, it is important to calculate the effective cost of carbon abatement as well as the societal costs of pollutant emissions for any specific diesel alternative. From a technical standpoint, it is important to consider how certain technologies may provide enabling services to the distribution grid, e.g., frequency regulation or black start.

Project-specific factors will undoubtedly impact these scenarios. If BTM assets were to exceed customer load, they would have to bid into energy markets, reducing the average value per MW generated outside of PSPS. Options outside the substation could look relatively more attractive once permitting costs and distribution upgrades are added to the capital investment. Both BTM and IFOM assets could improve their economics if there are locations for which they can receive RA contracts.

Evaluation Approach: Technical

Based on the technical specifications listed in PG&E's Clean Temporary Generation RFO, 11 technical parameters are evaluated for each technology:

- 48-hour deployment
- Black start capability
- Cold load pickup
- Load acceptance
- Load following
- Inertia/frequency response
- Fault duty
- Power density/footprint
- Mobility
- NFPA safety
- 48-hour PSPS-Capacity Factor

All of these parameters are weighted equally toward a comprehensive Technology Feasibility Index. The index does not necessarily represent how well a technology can perform during an actual PSPS event; particular conditions at a substation could favor one parameter more heavily than others. Other technical challenges could exist that are not addressed by this list.

Each parameter is scaled between 0 (unfavorable) and 1 (favorable), and all of the parameters are summed to a Technology Feasibility Index. While some technical factors such as power density can be quantified and compared easily, this is more challenging for others, such as inertia. As such, each parameter's evaluation framework is unique and discussed in detail below. While most of these scores are based on data, some have been developed qualitatively through expert interviews.

48-hour deployment

The 48-hour deployment time is a requirement for technologies that will be deployed in the hub-and-spoke operating mode. Technologies that can be transported and deployed directly as a containerized module can often fulfill this requirement. Some skid-mounted technologies such as Bloom Energy's fuel cell are technically mobile yet require up to three or more days to deploy, demobilize, and ramp and thus do not fulfill this requirement.

Black start capability

A black start resource is a generation asset that can start without support from the grid. A small synchronous generator, such as a diesel or a gas turbine generator, is traditionally used to black start the grid with a small local battery as a source of power support for the synchronous machine.[7] The challenge of communicating with and controlling DERs currently makes them infeasible for black start.

Cold load pickup

The PG&E RFO requires technologies to handle the high in-rush current with no external sources to assist during cold load pickup, and the block cold load capability for generators must be a minimum of 60% of the generator nameplate capacity. We combine vendors' RFO responses, August 2020 CPUC presentations, and verbal feedback on this requirement into a binary score. Technologies that can fulfill this requirement are rated 1, while technologies that cannot perform this task independently are rated 0. FuelCell Energy, for example, can only meet these criteria with the help of an ancillary generator, and thus is deemed to have no cold load pickup capability.

Load acceptance

The load acceptance parameter provides a more quantitative evaluation of technologies' performance during startup and initial ramping phase. A diesel generator does not need time to warm up from a cold start and has a load acceptance as high as 80% with no preloading, outperforming all other technologies. A natural gas reciprocating generator such as the Enchanted Rock solution can start up within ten seconds but can only offer a load acceptance of 60%. Natural gas turbine solutions have inferior load acceptance to gas reciprocating generators because they need 3-5 minutes to warm up before they can start to accept step loads. When a natural gas turbine is switched to run on hydrogen fuel, its ramp rate is impaired to a small degree[8], so its load acceptance is rated lower than a regular natural gas turbine.

The ramp rates of fuel cells are generally lower than turbine technologies, and they vary significantly with the cell operating temperatures. Polymer electrolyte membrane (PEM) fuel cells operate at a relatively low temperature and can quickly vary their output to meet shifting power demands. A 5kW PEM fuel cell can ramp 93% of its capacity in 0.1 seconds. This could be improved further as capacity increases.[9]

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[7] Wei, S. Black Start Capability Assessment in Power System Restoration, IEEE.
[8] ETN global. Hydrogen gas turbines - the path towards a zero-carbon gas turbine.
[9] Nikiforow, K. et al. Power ramp rate capabilities of a 5 kW proton exchange membrane fuel cell system with discrete ejector control. Journal of Power Sources, 2018.

Molten carbonate and solid oxide fuel cells, on the other hand, operate at a high temperature range of 700°C–1000°C. As a result, they must be warmed up over 12-14 hours, with ramp rates limited to 10-20kW/s[10]. The same limitation applies to biomass plants; due to their low ramp rates, these plants are often only intended for baseload production, so their load acceptance parameters are scaled to 0.1. Solar and BTM technologies are assumed to have zero load acceptance capability because solar is fundamentally an unreliable power source, and in any case, BTM technologies currently face the challenge of real-time communication with the rest of the grid.

Load following

A technology that can automatically ramp its power output up and down fast enough to respond to variable demand can perform load following. According to vendor responses and literature reviews, reciprocating generators, turbines, and PEM fuel cells have full load-following capability. Energy storage systems have the technical ability to follow the load but are not granted a full score due to their limited discharge durations.

Inertia/frequency response

Grid frequency, which indicates the balance of electricity's supply and demand, can drop if a large power plant or transmission fails or if large loads enter suddenly. Inertia resists these changes in frequency, giving the grid time to rebalance supply and demand. Traditionally, the inertia is provided by synchronous generators, including diesel, gas turbine, and ORC generators used by biomass plants. However, as the number of inverter-based resources (IBRs) grows in the system, the role of synthetic inertia becomes more important. Synthetic inertia is the fast frequency response that IBRs can provide within milliseconds after a contingency. This slows down frequency shifts and can give enough time for generation capacity to phase in or out.

NREL researchers commented that such rapid response from IBRs can mimic or even supersede traditional frequency responsive reserves and proposed a framework for designing an inverter-based grid. Despite the promise proposed by the researchers, the inertial response emulation study that PG&E completed in 2019 showed that synthetic inertia alone did not resolve all the frequency criteria violations created in low-inertia simulations. A persistent number of issues remained regardless of the high deployment of synthetic inertia resources, showing that synthetic inertia is not a one-to-one replacement for mechanical inertia. Therefore, the inertial capability of all inverter-based technologies is discounted to 0.8. However, linear generators have a unique inertia-preserving mechanism: its linear oscillators drive the kinetic motion inside a generator. When a power shutoff happens, the oscillators will dissipate energy faster than a heavy rotating mass in a typical synchronous generator. Out of this consideration, the inertia of a linear generator is discounted to 0.7.

Fault duty

A protective relaying scheme is required to protect the system from abnormal voltage and frequency conditions. Generators must have the ability to generate short circuit fault duty for various fault types to allow traditional overcurrent protection to be used to detect and clear utility primary faults successfully.

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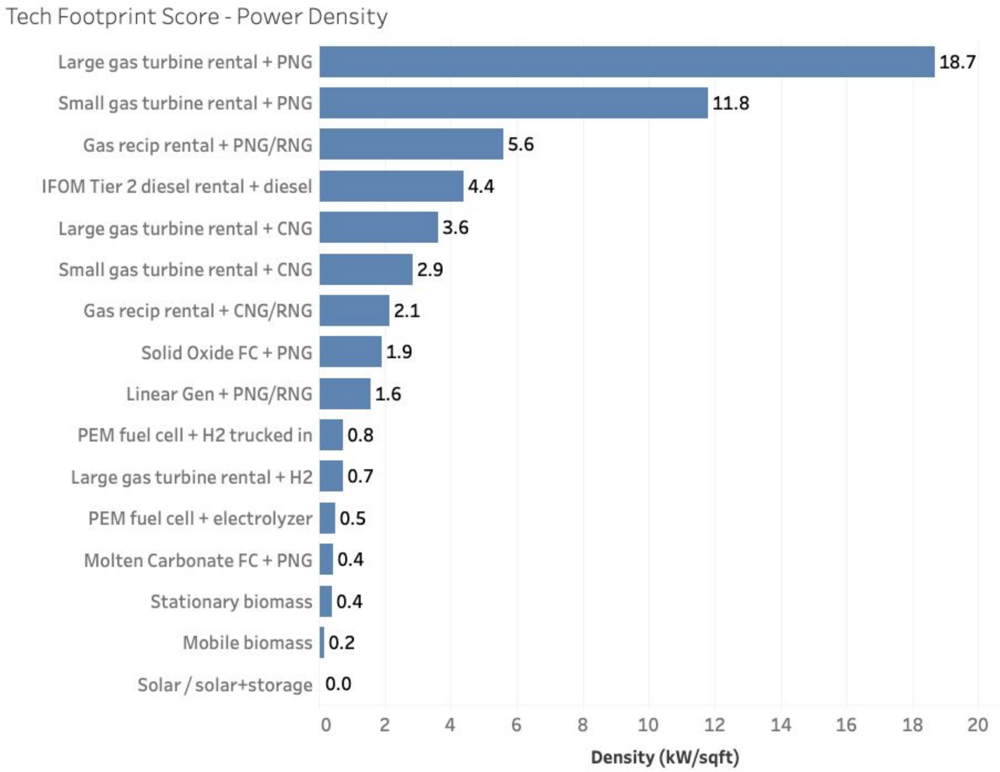
[10] Fuel cell datasheets from Doosan and Bloom Energy.

PG&E requires all technical solutions to provide at least 250% of their nameplate current as their fault current contribution or fault duty (vendors have suggested that this 250% requirement could be relaxed). Diesel generators are the only solution that can meet this requirement without ancillary equipment. Enchanted Rock indicated in their August 2020 CPUC presentation that this is one of the two requirements their technology cannot fulfill without technical add-ons. A natural gas turbine performs even worse than a gas reciprocating generator because turbines tend to flex under high current. Due to the lack of physical inertia, inverter-based technologies can only provide 120-150% of fault duty. One solution to the fault duty limitation is to include a synchronous generator or condenser in the circuit, as proposed by FuelCell Energy and Bloom Energy in their presentations during the August 25 CPUC workshop.

Power density

Power density is calculated using each technology's power capacity and its corresponding physical footprint. Natural gas turbine generators generally have the highest power density; for example, Caterpillar's Solar Turbine is a 5.7MW mobile gas generator that can fit in a 50' trailer container. The power density values of other technologies are all benchmarked against the value of this natural gas generator. Fuel storage space is accounted for when we calculate the footprint of technologies that require on-site storage. Because BTM technologies do not require any space at the substation, they should be effectively treated as a high power density option. In reality, land use issues can present challenges for BTM options as well, though the use of existing space, e.g., rooftops, can mitigate those issues. To make this analysis more intuitive, we have given solutions such as solar + storage low power density scores. However, the utilization of existing roofs, garages, and parking lots can fully mitigate that concern in some instances.



Mobility

Technologies that have proven commercial mobile products are set to 1. If mobility has been proposed by developers but not proven, the mobility value is discounted to 0.5. If a technology is completely immobile and requires stationary installation, its value is 0.

NFPA Safety

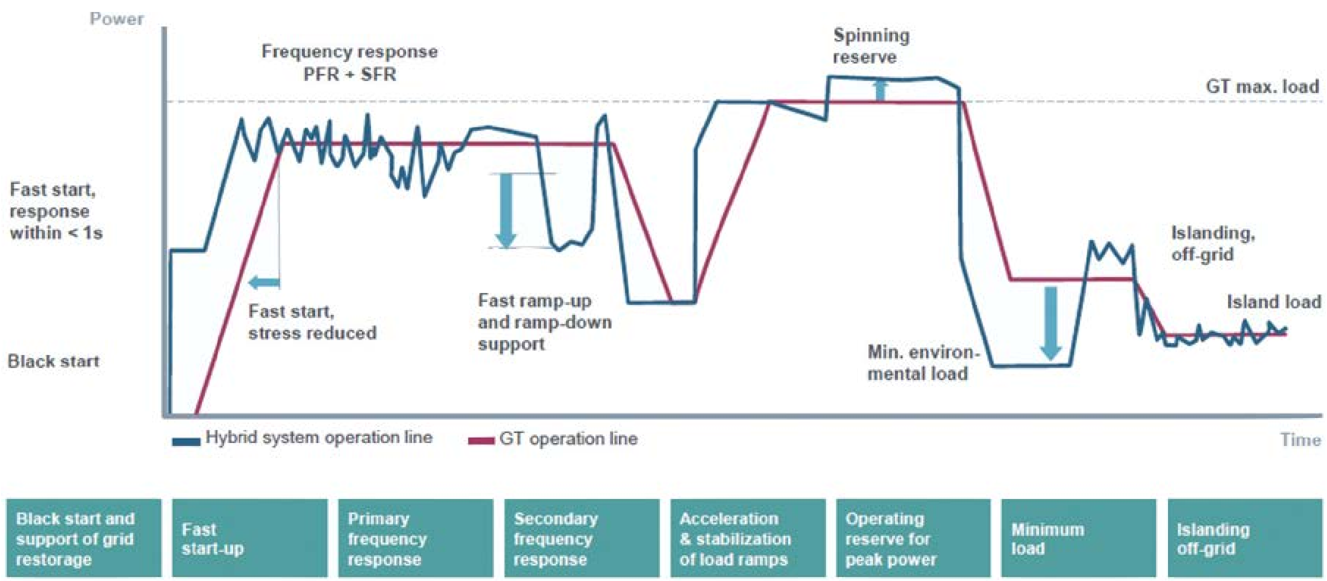
The National Fire Protection Association (NFPA) developed a system for indicating the health, flammability, and reactivity hazards of chemicals. Diesel is ranked with Level 2 flammability and Level 2 health score, meaning the fuel must be moderately heated before any ignition can occur. Still, it can cause incapacitation or residual injury during continuous exposure. On the other hand, hydrogen and natural gas have a Level 4 flammability and Level 1 health score, which means the fuels can completely vaporize at normal pressure and temperature and burn readily but have fewer health impacts from exposure. Using this established chemical safety rating system allows us to quantify the hazard associated with transporting, storing, and utilizing these different fuels. It should be noted that this NFPA Safety score is based on fuel, not equipment.

48-hour PSPS-Capacity Factor

A PSPS-Capacity Factor for a technology is defined as the expected power output in a 48h PSPS event relative to its nameplate power capacity. Factors that affect technologies' PSPS power output include technology efficiency, operation and maintenance interruptions, and engineering design for accommodating unexpected load spikes. In another sense, it measures the degree to which a technology would need to be oversized to be a single solution. For example, most lithium-ion battery applications would be utilized for roughly 4 hours per day during PSPS. The most likely scenario is that those batteries would only be used for peak shaving and potentially to mitigate natural gas load block issues. Hypothetically, if batteries were to be a single solution, they would require significant oversizing, presuming space constraints could be overcome. It should be noted that, based on guidance from PG&E, no generation capacity factors during PSPS can feasibly reach close to 100% as equipment would have to operate at a reduced capacity (suggested ~80% by PG&E) to accommodate ramp up for load spikes. As such, these measures as modeled can differ from published specifications because of how the equipment would be administered and operated during PSPS events.

Technical Feasibility Score

Although diesel generators have the highest Technical Feasibility Scores, pairing other technologies can potentially provide the same or even improved technical performance. A natural gas turbine paired with batteries is a popular hybrid configuration. As shown by the natural gas turbine and the hybrid system load curves below, battery systems can enhance the startup of the natural gas turbine and enable it to provide much faster service such as frequency response, ramp-up and ramp-down service. Further analysis of technology hybridization can be found in the team building section below.



Technical Feasibility Scores

Technology	Power Density	Black Start	Load Acceptance	Mobility	NFPA safety	48h deployment	Cold load pickup	Fault duty	Inertia/ frequency response	Load following	PSPS Capacity Factor	Total technical feasibility score
Diesel/HVO recip	0.8	1.0	1.0	1.0	0.3	1.0	1.0	1.0	1.0	1.0	0.8	9.8
Small NG turbine + PNG	1.0	1.0	0.6	1.0	0.2	1.0	1.0	0.7	1.0	1.0	0.8	9.3
Natural gas recip + PNG	1.0	1.0	0.8	0.5	0.2	1.0	1.0	0.8	1.0	1.0	0.8	9.0
Small NG turbine + CNG	0.5	1.0	0.6	1.0	0.2	1.0	1.0	0.7	1.0	1.0	0.8	8.8
Natural gas recip + CNG	0.4	1.0	0.8	0.5	0.2	1.0	1.0	0.8	1.0	1.0	0.8	8.4
Lithium-ion storage	0.4	1.0	1.0	1.0	1.0	1.0	1.0	0.5	0.8	0.5	0.1	8.3
Flow (ZnBr) storage	0.1	1.0	1.0	1.0	1.0	1.0	1.0	0.5	0.8	0.5	0.1	8.0
Flow (VRB) storage	0.1	1.0	1.0	1.0	1.0	1.0	1.0	0.5	0.8	0.5	0.1	8.0
Large NG turbine + PNG	1.0	1.0	0.5	1.0	0.2	0.0	0.0	0.7	1.0	1.0	0.8	7.2
Flow (Fe) storage	0.1	1.0	1.0	1.0	1.0	0.0	1.0	0.5	0.8	0.5	0.1	7.0
BEB + V2G charger	0.1	1.0	1.0	1.0	1.0	0.0	1.0	0.5	0.8	0.5	0.1	7.0
Large NG turbine + CNG	0.6	1.0	0.5	1.0	0.2	0.0	0.0	0.7	1.0	1.0	0.8	6.8
H2 gas turbine + compressed H2	0.1	1.0	0.4	1.0	0.2	0.0	0.0	0.8	1.0	1.0	0.8	6.3
Flywheel	0.1	1.0	1.0	0.0	1.0	0.0	1.0	0.5	1.0	0.5	0.1	6.2
Mobile biomass	0.0	1.0	0.1	0.5	1.0	0.0	0.0	1.0	1.0	0.0	0.7	5.3
Linear Gen + PNG	0.3	1.0	0.1	1.0	0.2	0.0	0.0	0.5	0.8	0.5	0.8	5.1
Stationary biomass	0.1	1.0	0.1	0.0	1.0	0.0	0.0	1.0	1.0	0.0	0.7	4.8
BTM commercial storage	0.4	0.0	0.0	1.0	1.0	1.0	0.0	0.5	0.8	0.0	0.1	4.8
PEM + compressed H2	0.1	1.0	0.4	0.0	0.2	0.0	0.0	0.5	0.8	1.0	0.7	4.7
BTM commercial PV+storage	0.0	0.0	0.0	1.0	1.0	1.0	0.0	0.5	0.8	0.0	0.3	4.6
BTM residential PV+storage	0.0	0.0	0.0	1.0	1.0	1.0	0.0	0.5	0.8	0.0	0.3	4.6
Gravity storage	0.0	1.0	0.4	0.0	1.0	0.0	0.0	0.5	0.8	0.5	0.3	4.5
Solid oxide fuel cell + PNG	0.1	1.0	0.1	0.5	0.2	0.0	0.0	0.5	0.8	0.0	0.7	3.9
Mobile solar	0.0	0.0	0.0	1.0	1.0	1.0	0.0	0.5	0.0	0.0	0.3	3.7
Molten carbonate fuel cell + PNG	0.3	1.0	0.1	0.0	0.2	0.0	0.0	0.5	0.8	0.0	0.7	3.6
Stationary solar	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.5	0.0	0.0	0.3	1.7

Evaluation Approach: Environmental

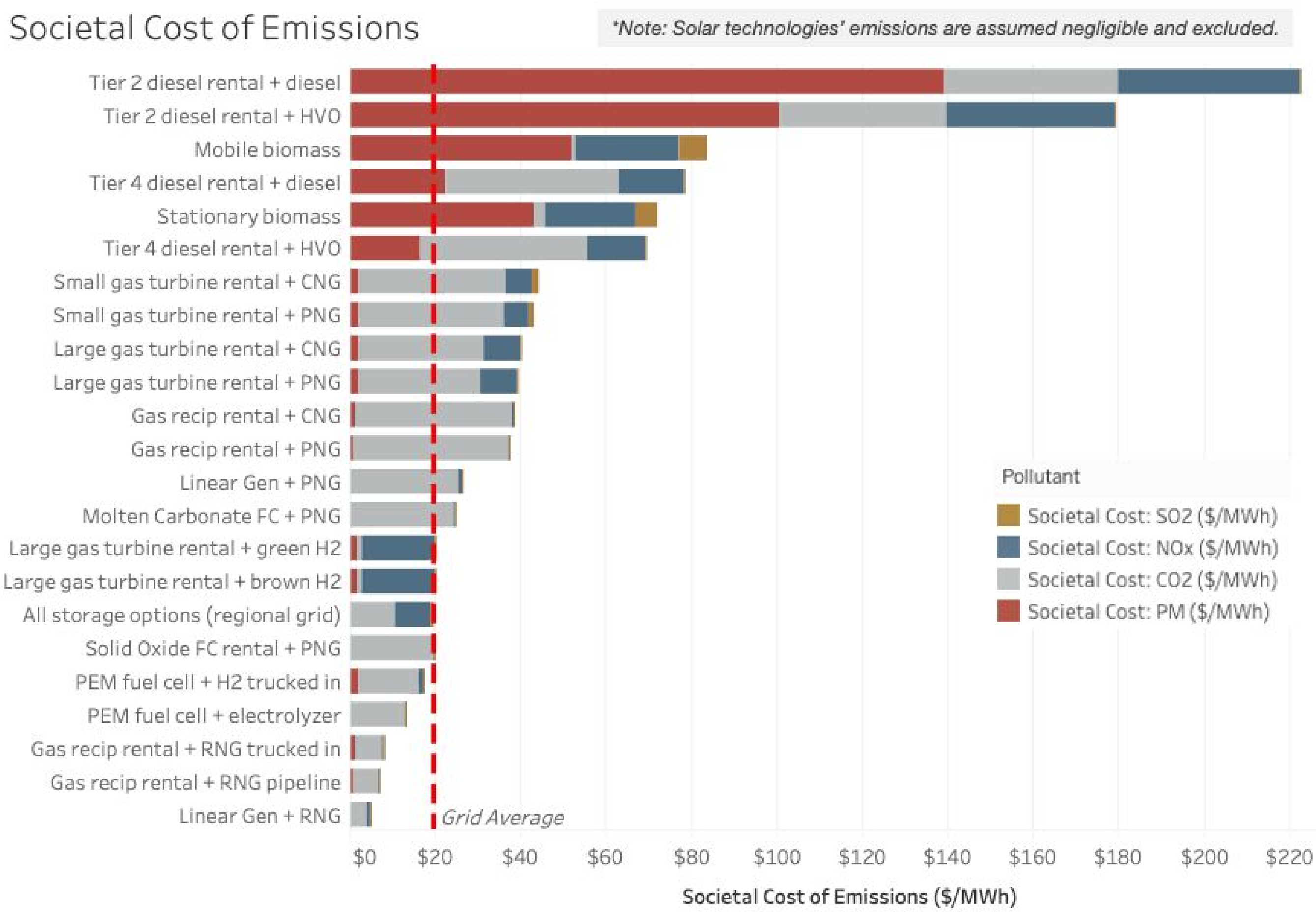
Different technologies have different associated externalities - namely, CO_2 and pollutant emissions, including PMs, NOx, SO_2, CO, and VOCs - for every MWh produced. The environmental effects of various technologies are evaluated not just from operation but from fuel transportation using diesel trucks (i.e. delivery), and the emissions from the diesel truck are calculated using EPA diesel engine emission standards. Therefore, though certain fuels may be considered carbon-neutral, e.g., biomass, they can still cause emissions based on this analysis framework. All of the emissions for single technologies are demonstrated in the table below.

Environmental Evaluation (color = comparison to diesel reference)

	CO2 (lbs/MWh)	Particulates (lbs/MWh)	NOx (lbs/MWh)	SO2 (lbs/MWh)	CO (lbs/MWh)	VOC (lbs/MWh)	Noise (dBa)
Tier 2 diesel rental + diesel	1,565.11	0.44	4.28	0.02	7.73	0.42	86.00
Tier 4 diesel rental + diesel	1,565.11	0.07	1.50	0.02	7.73	0.42	86.00
Tier 2 diesel rental + HVO	1,502.91	0.32	3.99	0.00	7.34	0.42	86.00
Tier 4 diesel rental + HVO	1,502.91	0.05	1.40	0.00	7.33	0.42	86.00
Gas recip rental + CNG	1,418.58	0.00	0.04	0.01	1.10	0.00	69.00
Gas recip rental + PNG	1,395.00	0.00	0.00	0.01	1.09	0.00	69.00
Small gas turbine rental + CNG	1,325.18	0.01	0.63	0.04	0.61	0.07	69.00
Small gas turbine rental + PNG	1,303.90	0.01	0.60	0.04	0.61	0.07	69.00
Large gas turbine rental + CNG	1,117.83	0.01	0.89	0.00	5.25	0.00	69.00
Large gas turbine rental + PNG	1,099.52	0.01	0.86	0.00	5.24	0.00	69.00
Molten Carbonate FC + PNG	939.00	0.00	0.01	0.00	0.00	0.00	65.00
Solid Oxide FC + PNG	751.50	0.00	0.00	0.00	0.03	0.02	70.00
PEM fuel cell + H2 trucked in	542.81	0.01	0.13	0.00	0.03	0.01	54.00
PEM fuel cell + electrolyzer	496.50	0.00	0.00	0.00	0.00	0.00	54.00
All storage options (regional grid)	412.34	0.00	0.83	0.02	0.00	0.00	60.00
Gas recip rental + RNG trucked in	240.06	0.00	0.04	0.01	1.10	0.00	69.00
Gas recip rental + RNG pipeline	216.48	0.00	0.00	0.01	1.09	0.00	69.00
Stationary biomass	103.48	0.14	2.13	0.13	2.84	0.07	85.00
Large gas turbine rental + brown H2	46.31	0.00	1.77	0.00	0.05	0.01	69.00
Large gas turbine rental + green H2	46.31	0.00	1.77	0.00	0.05	0.01	69.00
Mobile biomass	20.00	0.17	2.48	0.17	3.63	0.08	75.00
All solar-based options	0.00	0.00	0.00	0.00	0.00	0.00	60.00

The societal cost of CO_2 - the only greenhouse gas evaluated - is based on the value forecasted by the Federal Interagency Working Group of $52 per ton (adjusted from 2007 to 2020 dollars). **However, the health and environmental externalities of non-GHG pollutants are non-trivial**. For instance, fine particulate matters ($PM_{2.5}$ and PM_{10}) can penetrate deep into human lungs, causing vital respiratory and cardiovascular conditions and increased mortality risk. The “Estimating Air pollution Social Impact Using Regression” (EASIUR) model created by the Carnegie Mellon University (CMU) Center for Climate and Energy Decision Making quantifies the impact that pollutants NOx, PMs, and SO_2 have on human health, net agricultural productivity, and ecosystem services as a **societal cost ($/ton)** for each pollutant.[11] Pollutants with low emission volumes yet high social impact are assigned a higher social cost, e.g., PMs at $631K per ton. To capture the full spectrum of each technology’s societal impact, emission rates of the four pollutant emissions (in tons/MWh) are multiplied by the pollutant-specific social costs (in $/ton) and summed into a total emissions impact value (in $/MWh) as shown in the chart below.

[11] Heo, J.; Adams, P. J.; Gao, H. O. Reduced-form modeling of public health impacts of inorganic PM2.5 and precursor emissions. *Atmos. Environ.* **2016**.



Diesel generators have the highest social cost of emissions, ~75% of which is attributable to PMs. Some of these impacts can be alleviated by switching to HVO, but the total societal cost remains high compared to other technologies modeled. PMs are also an issue for biomass plants: ash and tar are produced during biomass gasification and combustion. Although a downstream filtering unit can capture most pollutants, a complete removal is expensive and nearly impossible.

CO_2 is the largest emission stream of natural gas generators, including advanced technologies like fuel cells and linear generators. Switching to RNG is an effective way to cut down carbon emissions in this case; more than 80% of emissions can be avoided by adopting the cleaner alternative fuel.

The emissions of a battery energy storage system (BESS) are directly related to its power source. When used as a standalone unit, its emissions are assumed equivalent to the regional grid average. But when paired with (and charged solely by) solar PV, BESS emissions are considered zero. In our analysis, we assume standalone batteries would be charged by the grid before PSPS events, and therefore should be attributed to grid-average emissions when discharging during PSPS events.

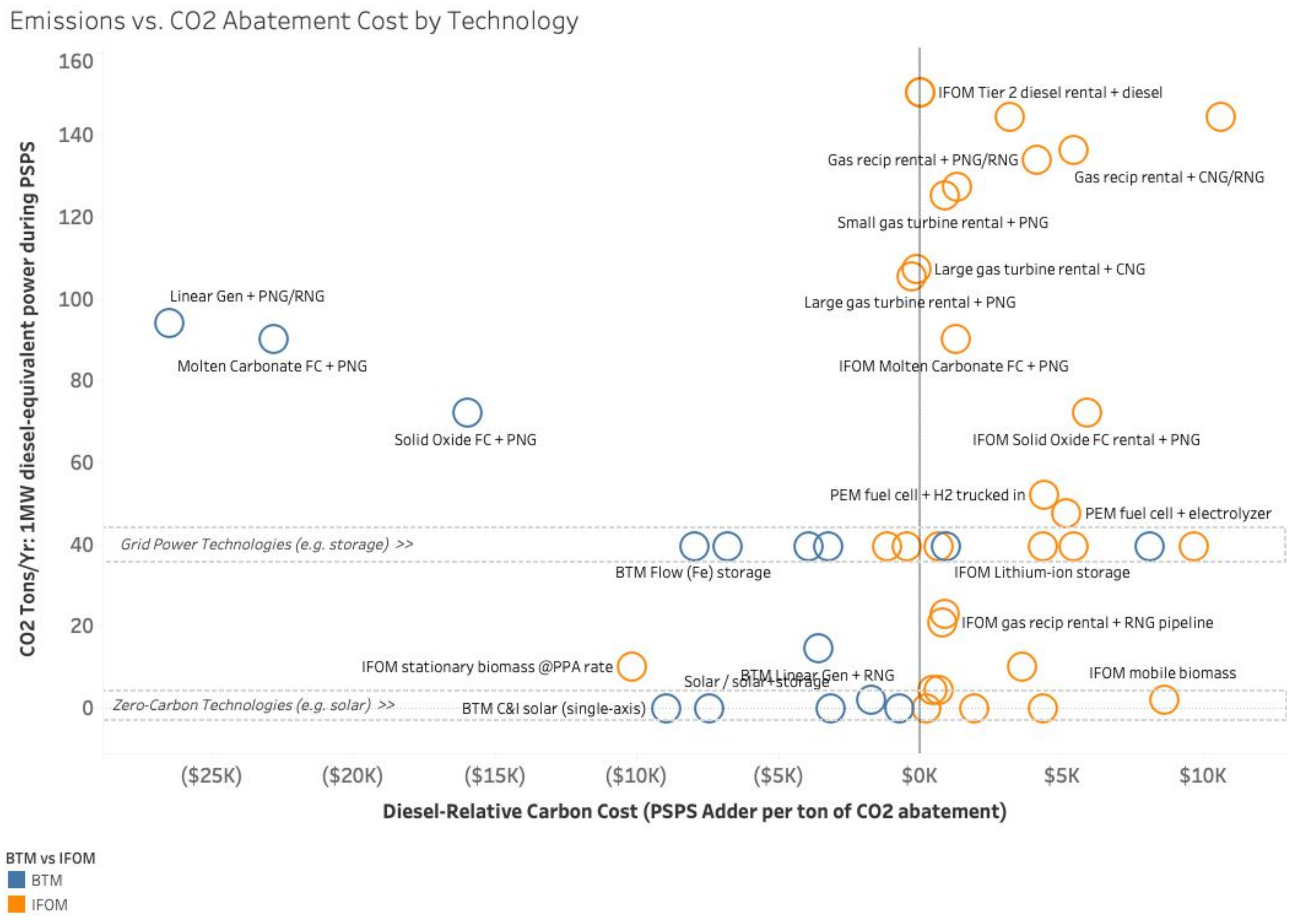
As shown in the graph below, the total societal emissions impact of different fuels are broken down into two stages - fuel transportation and fuel combustion. **The emissions from fuel transportation are low compared to the emissions generated from fuel combustion, especially for high-emission fuels like diesel.** Because hydrogen is a fuel with low volumetric mass density, it needs to be transported more frequently than other fuels to sustain a generators' operation. Therefore, compared to other fuels, a higher percentage of hydrogen's total lifecycle emissions are attributed to the transportation stage.

Despite the desirability of low or zero emissions, the tradeoff between emissions and cost cannot be overlooked when evaluating a technology's attractiveness. **To better understand a technology's cost and environmental performance relative to diesel - at least from a CO_2 perspective we calculate a diesel-relative carbon cost,** CC_{dr}:

$$CC_{dr} = (C_i - C_{diesel}) / (E_{diesel} - E_i)$$

where C_{diesel} is the annual cost of renting 1MW of diesel power for PSPS; C_i is the annual net cost of providing 1MW diesel-equivalent power during PSPS; E_{diesel} is the total CO_2 emissions from diesel during PSPS; and E_i indicates the emissions of each single technology providing 1MW diesel-equivalent power during PSPS. **Diesel equivalence is foundational because certain technologies (e.g., solar and batteries) have lower capacity factors during PSPS**. For example, it would take 6MW of four-hour batteries to provide the energy a 1MW diesel generator can supply in 24 hours. All of the costs are calculated in the framework introduced in the Economic Evaluation section.

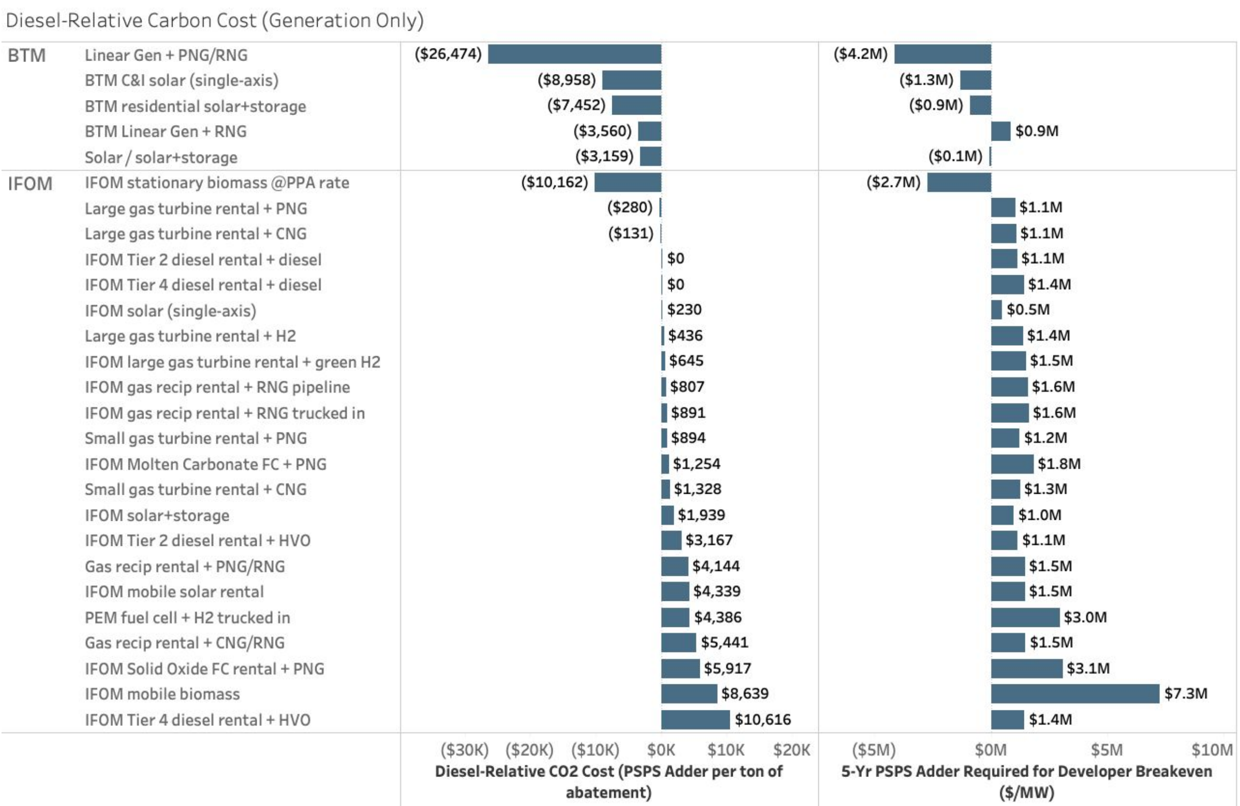
While particulate emissions are responsible for the highest societal cost of emissions for the reference case diesel, the cost of CO_2 emissions has been more widely recognized and discussed. As such, CO_2 is the cost-relative pollutant modeled in this analysis below. **Also note that even though most of the technologies are assumed to operate outside PSPS to earn energy revenue, we only account for emissions produced during PSPS**. For instance, the annual cost of using a lithium-ion battery in front of the meter to supply 1MW diesel equivalent power for four 48-hour PSPS events is roughly $1M, and its emissions during this period are around 30 tons (based on grid power used to energize the batteries). Compared to the ~$225K annual cost and 113 tons of a diesel generator's carbon emissions, the diesel-relative carbon cost of a lithium-ion battery is roughly $6,764 per ton. The E_i and CC_{dr} values of each technology are illustrated in the figures below.



Technologies with negative CC_{dr} values are those with both lower cost *and* emissions than diesel. These tend to be BTM technologies with low OpEx, e.g., solar and storage. The linear generator outperforms due to its relatively low CapEx and high efficiency. In contrast, standalone BESS have relatively high CC_{dr} estimates due to their low capacity factors and high CapEx - though, as demonstrated by solar+storage, this can be improved by pairing BESS with renewable generation sources. We discuss more in-depth evaluations of cost and environmental performance in the following section.

The implications of this analysis are significant. Certain technologies cost less than diesel - such that there is a double benefit of cost reduction and carbon abatement - but the vast majority of technologies have a high cost of carbon emissions, many in the range of thousands of dollars per ton. This is mainly because **this analysis *only* includes the delta in emissions during PSPS events** - that is, eight days per year over five years for a total of 40 days of operations. In any given year, the actual number of days of PSPS events could be higher or lower.

Among reciprocating engines and turbines, only large gas turbines are estimated to have a negative diesel-relative carbon cost. Other options can be in the hundreds or even thousands of dollars per ton of CO_2 abated. As outlined in the option value section above, the cost advantage of a large gas turbine of 34 MW can preclude any optionality in scaling a solution up or down over time.



To holistically compare against a commonly offered cost of carbon - such as $52/ton - one must consider the year-long carbon reduction outside of PSPS events from cleaner generation solutions that can support the grid or customers throughout the year. **Clean options such as solar + storage would drive that significant benefit not captured in the analysis above due to their year-round operation**

beyond PSPS. **Conversely, a clean*er* option such as a fuel cell powered by natural gas could increase year-round carbon emissions if natural gas-powered technologies produced power throughout the year.**

Single Technologies: Leaders and Laggards

PSPS event mitigation requires the unique challenge of energizing and managing an independent grid within each load pocket, and the various substations included present different requirements and limitations. The 20 substations on which this analysis is focused (out of 62 substations identified at risk in 2020) range from 4 to nearly 70 MW in peak load, while minimum load ranges from 2 to 26 MW. Further, the 20 representative substations feature four different character load shapes (commercial, standard, non-standard, and monolith). **Finally, the substations have varying space limitations for co-locating base generation sources, in some cases precluding space-intensive solutions such as storage. These differences illustrate the inherent challenges with a one-size-fits-all solution regardless of future PSPS event frequency and length.**

PG&E chose diesel generation as a near-term solution due to its reliability, flexibility, low fuel ignition risk, fault handling, scalability, and commercial availability. Diesel generators temporarily sited at substations from May-November 2020 range from 500kW to 2MW in capacity apiece (to be sited in parallel up to a substation's expected load) and require ancillary equipment such as fuel tanks and spill basins. Although diesel is technically effective due to benefits such as black start capability and fast ramp rate, diesel generation has substantial economic and environmental downsides. Further, a 1.5MW tier 2 diesel generator burns through roughly 110 gallons of diesel fuel per hour[12], costing $0.30 per kWh and resulting in nearly half a pound of particulates and over 1,500 lbs of CO_2 per MWh in addition to relatively high PMs, NOx, and other pollutants.

Solutions at the Substation

Both mobile and stationary solutions co-located at substations were considered in this analysis, and each option offers a different set of benefits and costs. Stationary installations offer reduced logistics overhead and avoid repetitive installation costs, but typically require additional setup costs and are subject to limited utilization. **Mobile options, on the other hand, optimize utilization** (as 1 MW could cover more than 1 MW of capacity by moving flexibly) **and minimize over-procurement risk** but could add logistics costs and complexity if moved off-site during non-PSPS.

It is likely that any equipment requiring significant installation costs (e.g., natural gas pipeline extensions) are only cost-beneficial with multi-year contracts. Therefore, we consider both stationary and mobile options with this understanding. (It is also possible for mobile options to be left at substations for entire seasons or even multiple years until they are deemed superfluous or obsolete.) While most commercially viable options were evaluated for most technology types, it should be noted

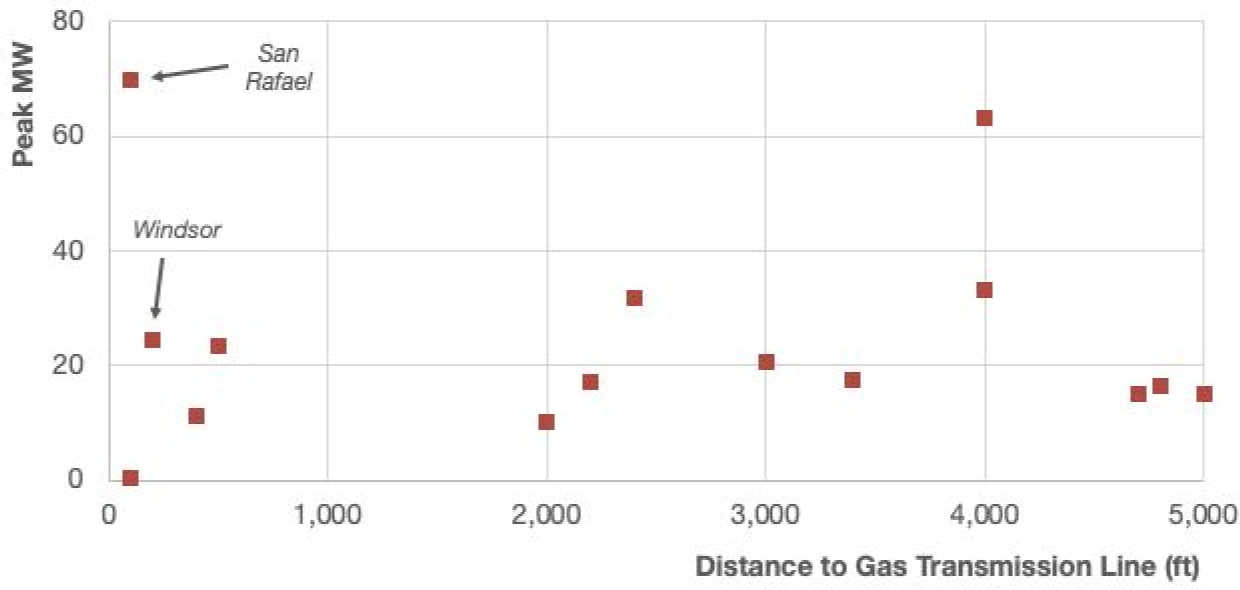
[12] Aggreko customer service, via website chat.

that both PG&E and the CPUC are unlikely to approve any permanent installations of diesel or natural gas generation dedicated solely to PSPS event support.

Natural gas-fueled turbines, reciprocating engines, linear generators, and fuel cells are modular, commercially available, and substantially cleaner than diesel. Most of these solutions are load-following but have varying levels of ramp rate (e.g., Bloom Energy fuel cells can take up to 24 hours for full ramp due to high operating temperature) and spatial needs, making it challenging to identify a clear winner for all substations. However, gas turbines could be paired with 15-minute batteries (which are much lower cost than four-hour batteries) to solve for load block challenges. Alternatively, natural gas reciprocating engines such as those from Enchanted Rock can offer more similar performance to diesel due to their higher heat rate. Such a solution would require roughly $1.5M per MW in adders over five years, about 25% more than the diesel reference.

Gas generation vendors have indicated that gas transmission - not distribution - line access would be necessary to provide the pressure required to energize entire load pockets[13]; otherwise, such equipment may require costly and space-intensive onsite storage as well as refueling options on standby. PG&E has indicated that **connecting substations to gas lines more than 1,000 feet away could be cost-prohibitive**; indeed, even among the substations located within 1,000 feet, some substations may not warrant line infrastructure upgrades given their relatively small size.

The graph below demonstrates the relationship between substation peak load and distance to a gas transmission line for a small group of substations with known distances. Substations for which gas generation could make the most sense are San Rafael and Windsor, which are relatively high-capacity but would only require up to 200 feet of new infrastructure for pipeline access.



[13] Conversation with Enchanted Rock.

Several hydrogen-based options were evaluated (PEM fuel cells, solid oxide fuel cells, and combustion turbines) as it is a zero-emission storage medium (not including energy generated and used for electrolysis) and is relatively energy-dense in liquid form. However, **hydrogen today presents significant barriers for storage**, i**ncluding cost and space**; hydrogen must either be stored as a compressed gas at 5,000+ PSI or as a liquid below -400 degrees F. **Pilots completed to date around the world have only demonstrated safe delivery of 20-30% hydrogen through natural gas lines, so the use of pure hydrogen would require onsite electrolysis or storage**. Meanwhile, electrolysis today remains costlier than natural gas; powering electrolysis with natural gas (the cheapest method) yields power costs roughly 2x that of purely using natural gas for power (and still could only be feasible by running natural gas lines to a substation).

PEM fuel cells would require estimated adders of roughly $3M (with hydrogen trucked in) to $3.4M (onsite electrolyzer) per MW over five years, while a hydrogen combustion turbine would require just over $1.3M. Renewables-powered hydrolysis is technically feasible but is expected to remain at least 10X more expensive than natural gas combustion over the time period of this analysis[14]. Finally, it should also be noted that hydrogen is highly flammable, a key risk factor during PSPS events. For these reasons, it may not be advisable to pursue hydrogen for substation baseload power during PSPS events at this time.

Although in the absence of subsidy, both stationary and mobile biomass generation options were the most expensive technologies modeled ($3.8M and $7.3 per MW in five-year adders modeled, respectively), biomass uniquely offers additional benefits. **Establishing a conveniently located biomass resource for upcycling pruned and removed vegetation could operate synergistically with a grid hardening strategy.** Further, biomass is considered renewable and, as of 2018, carbon neutral by the EPA when combusting vegetation from forest management. As described in the Environmental section above, biomass still has high NOx and SO_2 emissions that would have to be considered by any community evaluating a biomass power generation option. As for economics, PG&E's BioMAT program enables PPA pricing of ~$0.20 per kWh, which makes a plant profitable enough such that an additional adder or subsidy would not be required to make a project in-the-money. Therefore, **it may make sense to co-locate biomass facilities with substations near dense transmission line vegetation management areas as part of the BioMAT program.**

Since the availability of fuels largely constrains the feasibility of clean fuel technologies, we map the distribution of existing clean fuel plants and the overall generation potential in the state. As shown in the graphs below, there are fewer biodiesel plants than RNG plants in the state, but the two large biodiesel plants near the Bay Area, WIE-Agron BioEnergy and American Biodiesel, Inc., are potential fuel sources for substations that are not proximate to the pipeline. Together, these two plants produce 35 million gallons of biodiesel per year (3 million gallons per month)[15], sufficient to power 800MW of diesel generators for a 2-day PSPS event. As for renewable diesel, fuel supplier Targray has five fuel terminals in CA and produces billions of gallons per year, which is more than sufficient for PSPS power

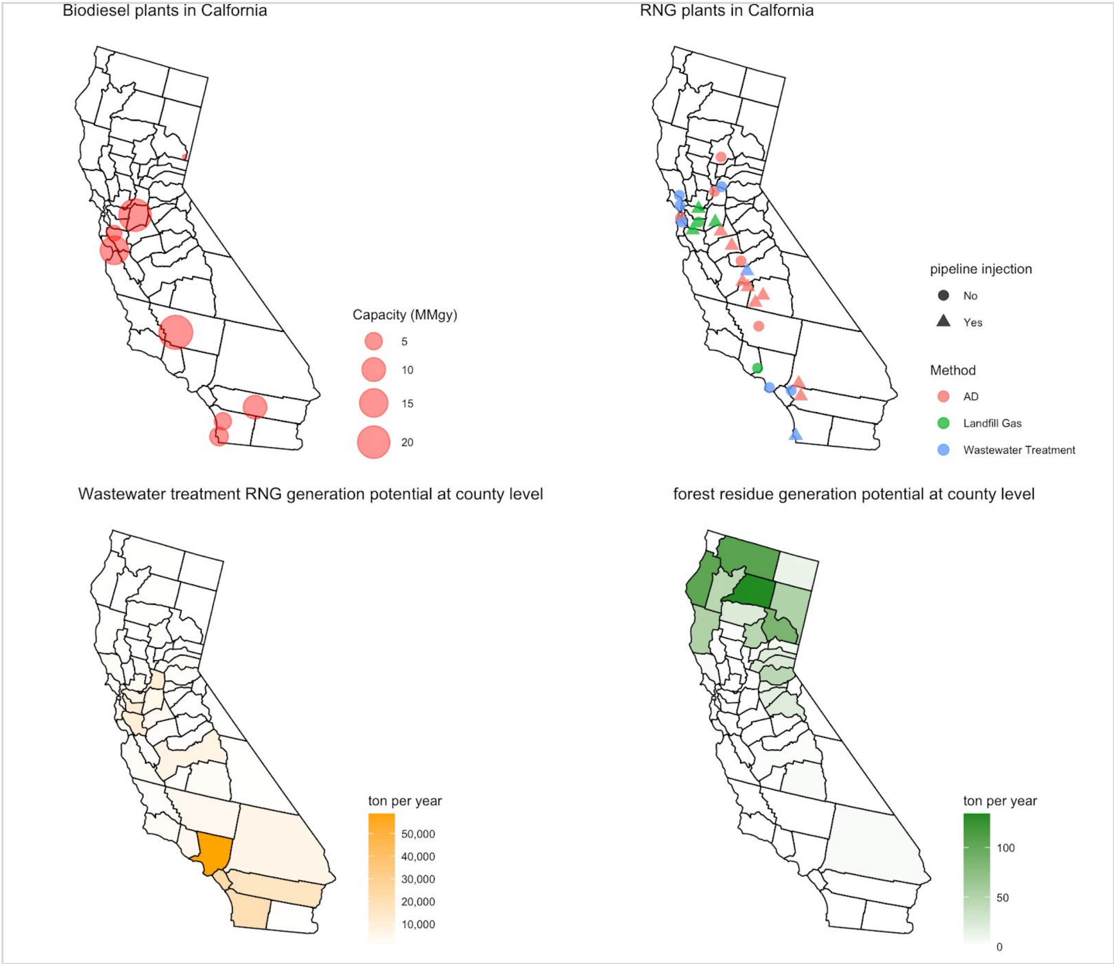
[14] Conversation with GE Gas Power.
[15] NREL biofuel Atlas

generation needs. The RNG produced near the Bay Area is primarily from wastewater treatment, anaerobic digestion (AD), and landfill gas. Wastewater treatment plants alone produce 18,200 MMBtu of RNG per month[16], which could supply 30MW of natural gas generators running continuously for two days each month. Although this figure is particularly high, there is healthy additional wastewater RNG generation potential, especially in Southern California.

Biomass, on the other hand, is a more location-dependent fuel than biodiesel and RNG. The majority of forest residues are collected from the Sierra Nevada Conservancy Area, where most existing biomass plants are located. Due to this location constraint, only substations proximate to the preserve area are likely to employ biomass technologies.

One important factor to note as it relates to RNG is that there are pathways to inject RNG into the natural gas pipeline system without actually trucking compressed RNG to substations. This may be the most cost-effective way of effectively fueling substations with RNG during PSPS events. **This approach is similar to that of purchasing Renewable Energy Credits (RECs) without actually producing on-site renewable energy.**

[16] Wastewater treatment plants performance data at City of Corona, Pleasant Grove Wastewater, Las Gallinas Valley and Ellis Creek



As for renewable generation, solar is a lower-cost option for co-locating at substations, though raised solar comes at an increased cost and would need to be evaluated for ability to withstand seismic activity. Solar could alternatively be IFOM but outside the substation due to low power density. Commercial-sized solar deployments in 2021 were modeled at a capital cost of roughly $1,200 per kW with relatively low fixed O&M at $14 per kW-year, leading to a potential estimated $1.2M in savings over five years. Mobile options are available, though they are costlier, requiring about 40% more than diesel in estimated five-year adders. One main drawback is solar's low power density (only ~15W per square foot for both permanent and mobile rental options), as space is limited at most substations, and co-located solar alone could only cover a small fraction of even minimum load at most substations. Another significant limitation is its inability to produce constant power, and as such, could only feasibly be used to provide partial-day power even when paired with storage. Lastly, solar availability during PSPS events is significantly threatened by ash and smoke that can block the sun's rays during wildfires. Anecdotally, ADL has been told that solar output during certain points in the September 2020 wildfires reduced solar output to 0-1%, effectively eradicating solar as a resource.

Nevertheless, solar sends a message that PG&E values clean solutions at a relatively low cost. **PG&E could explore the possibility of covering substations with solar — not just in the "available space," but also the entire substation footprint — to reduce the remaining required generation capacity while avoiding the loss of adjacent space**. It should also be noted that wind is likely infeasible due to its large footprint requirement (despite the availability of small modular and mobile rental options) and the coincidence of PSPS and Santa Ana wind speeds that exceed a typical turbine's safe operating range.

Storage resources modeled include lithium-ion batteries, vanadium redox flow batteries, zinc-bromine flow batteries, iron flow batteries, flywheels, and gravity-based storage. **Batteries have several benefits, including no fuel requirements, minimal variable costs** (enabling year-round market participation for peak reduction and ancillary services), and **vital peak reduction during PSPS events**. Drawbacks include limited duration (longer-duration storage resources beyond four hours are still in pilot phases), high capital costs, and a lack of rental options at scale. (It should also be noted that gravity-based storage is potentially the least costly, but existing commercial solutions cannot be located within small footprints at substations.) **As a result, batteries and flywheels co-located at substations are a potentially viable option but should largely act to support partner generation resources**. For example, four-hour duration flywheels could be cost-effective and year-round contributors but pack relatively light power density at just 400W per square foot. These resources can also be valuable outside of the substation footprint.

Because footprint is a primary concern with storage, the most appropriate storage technology for co-locating at substations may be lithium-ion, which is far from the cheapest storage technology modeled but could pack more than 2 kW per square foot. Storage resources would also be expected to participate in markets year-round, effectively smoothing peak demand for the entire load pocket and offering potential benefits like ancillary services and resource adequacy[17]. Even for resources with only four hours of storage duration, some level of co-located storage could effectively complement base generation.

Behind the Meter

BTM resources already available within affected load pockets currently cannot be harnessed during PSPS events due to a lack of remote integration and management capability. Due to growing renewables penetration within its service territory, **PG&E's distributed energy resources management system (DERMS) is in development but is not expected to become fully operational in the next 1-2 years. Therefore, BTM generation resources were analyzed with the understanding that they would not export power during PSPS events until sufficient control and communications systems are in place.**

The cheapest and cleanest resources modeled are residential and commercial BTM solar + storage, the combination of which is increasingly considered baseload power. Not only are these projects already among the cheapest methods for customers to procure power (and therefore require little to no

[17] RA credit would require deliverability, which may include significant upgrade costs that have not been evaluated.

additional financial support), but the storage component enables load and generation to be more closely matched, enabling localized peak load reduction. Commercial resiliency projects are picking up throughout the state, especially in fire-prone areas, often including storage alone (for cost savings, revenue streams, and resilience) without coupling with solar. **On the residential side, 50%+ of new residential solar installations in fire-prone areas include storage, representing substantial distributed resources and shrinking base loads.** Indeed, CCAs are already getting into this game, as three CCAs in the Bay Area recently announced a 20-MW storage aggregation pilot with SunRun across up to 6,000 homes. Both residential and commercial BTM solar + storage projects were modeled at a negative adder requirement - i.e. net savings to the developer - likely resulting in a lower required adder to incentivize participation in PSPS (if supported by grid infrastructure and policy changes). **Despite its year-round cost advantages, solar may not provide as much benefit to the load pocket during wildfires, as smoke and ash can significantly decrease its output during PSPS events amid a wildfire emergency.**

School and transit Battery Electric Buses (BEBs) are essentially mobile batteries, many of which have capacities in the range of 200-300 kWh, yet for grid participation would require a bi-directional or vehicle-to-grid (V2G) charging system. It may be possible for PG&E to make availability payments or incentives to bus owners in exchange for flexible use of the batteries during PSPS events or other critical events such as extreme peaks. Other utilities are already exploring symbiotic solutions with school districts and transit agencies: Southern California Edison recently launched a $350M program to upgrade distribution infrastructure to enable BEB and truck charging stations, and Dominion Energy recently announced a program to subsidize school district purchases of electric school buses while requiring the buses to be plugged in and controlled by Dominion for the summer for peak load reduction. These examples illustrate that while BEBs' five-year economics for PSPS events are not favorable (over $1M per MW in five-year adders projected), such projects may carry additional year-round benefits such as peak reduction and grid services as well as new revenue channels and positive PR. **In addition to exploring relationships with municipalities and school systems, PG&E could also explore the transition of its own vehicle fleets to electric, demonstrating how the system could and should work to other early adopters.**

Grid Services & Load Control

Distribution grid services such as frequency regulation and voltage support become more critical when load pockets island from transmission lines and DERs shoulder a higher share of generation. As discussed above, once a DERMS is ultimately in place, PG&E will theoretically be able to manage a 100% BTM DER-supported microgrid within each load pocket. However, **fully-distributed generation requires sufficient storage to match generation to load and grid services to maintain grid frequency and avoid faults or equipment failure/damage**. A 100% BTM grid has additional challenges - including but not limited to generation exceeding load, inertia concerns, critical event signaling, etc. - and therefore additional studies and pilots are needed to inform and facilitate this transition.

Individual technologies can fulfill this need in different ways. Smart inverters, in front of any storage or generation asset, can provide grid services. One example is Apparent Inc.'s platform, which provides reactive power to mimic a spinning generator and can provide greater grid stability at higher renewables penetration. Some storage assets such as flywheels can also provide ancillary services; Amber Kinetics' 8-kW flywheel, for example, offers four-hour duration storage as well as ancillary services. Both of these examples are remotely controllable and able to function in a PSPS; however, **similar solutions must be (1) integrated at a sufficient scale to handle shifting generation and load for an entire load pocket and (2) be capable of two-way communication with a PG&E DERMS.**

Load control solutions, especially peak reduction, can significantly reduce the complexity and scope of base generation needs. In other words, flattening the load profile of each load pocket during PSPS events reduces the base generation capacity required to keep lights on. Such solutions could come in many forms, including but not limited to:

- Shifting energy-intensive commercial and industrial activities at peak hours
- Additional bill credits for reducing household energy consumption during peak hours or participating in PG&E programs like SmartAC
- Requested (or mandatory) work-from-home for the remote-enabled workforce
- Restrictions on private and public EV charging during peak hours

Commercially available demand response (DR) solutions are estimated to cost in the neighborhood of $30 to $80 per kW-year, depending on volume, geography, and load profile. One program administered by EnergyHub includes a one-time payment (<$100) to smart thermostat owners in exchange for the right to control the thermostats during DR events; the cost is estimated at $70-$80 per kW-year, roughly half of the diesel availability cost per kW-year. The reliability of customers to perform during PSPS events has not been tested. Similarly, the ability to recruit appropriate DR customers in very small areas can be challenging.

C&I demand response programs are likely prohibitively expensive to tailor to individual load pockets. **One DR program to consider would be to incentivize customers in safe-to-energize, fire-prone load pockets to curtail demand based on time-of-day** (effectively a TOU demand response program only during PSPS). Regardless of program design, **load control solutions like DR are essential building blocks of an effective integrated plan** for future economic and environmental cost mitigation during transmission outages.

Technology Teams: Better Together

Because there is no single technology that consistently outperforms across all categories, grouping or "teaming" technologies could be a cost-effective way to minimize environmental impact - as well as space - while making up for technological limitations. For example, batteries cannot provide baseload generation much beyond four hours per day without significant oversizing. It would still make an effective team member to complement gas combustion by supporting load block and peak shaving. Similarly, a solar array above the substation may be a great addition to such a team by reducing capacity requirements at a low economic and environmental cost without compromising adjacent space.

ADL suggests a layering approach to team building for each substation type based on minimum/peak capacity, load profile, space availability, and access to fuel sources such as gas distribution lines and vegetation for biomass. Flexibility should also be considered to an extent; for example, Bloom Energy fuel cells could enable a gradual transition to up to 50% hydrogen without upgrades, and the environmental costs of batteries subside as fuel sources become cleaner.

This teaming approach also helps alleviate concerns around land use within the load pocket for solutions outside the substation. By tapping into a variety of clean solutions behind the meter - e.g., IFOM fuel cells beyond the substation, residential rooftop solar, commercial solar + storage, or commercial linear generator - it can be possible to provide a significant amount of load with more disparate land usage.

Just as basketball team lineups are built to balance the inclusion of attributes like height, ball handling, defensive prowess, and shooting abilities, technology teams are built with the core purpose of covering the inherent weaknesses and limitations of individual team members. In other words, every team needs at least one (but only one) technology to provide (1) consistent base generation, (2) inertia support, (3) fast ramp capability, and (4) some level of peak shaving, all while minimizing the economic and environmental costs of the entire team.

The following table outlines the prioritization framework of ADL's team-building approach, which mirrors the concept of Loading Order from the CPUC.

Layer	Sequential Tactic	Description and sample technologies
0	"Do No Harm"	• Ensure that older residential solar installations can be curtailed, if necessary, if generation in the load pocket exceeds demand
1	Reduce Net Load by Encouraging Islanding	• Support and encourage islanded BTM solar+storage where possible (e.g., solar+storage reducing net load during PSPS, but not controlled by PG&E)
2a	Leverage Available BTM Solar/Storage as Grid Assets (DERMS required)	• Utilize excess solar with smart inverters • Utilize BTM storage with smart inverters (peak load management) or V2G • Bi-directional charging of EVs, BEBs, and trucks
2b	Deploy Clean IFOM Options	• Permanent IFOM raised solar at most substations (typically <500 kW) • Use/reserve biomass generation where feedstock is abundant and project are already underway • Deploy the best technologies that emerge from pilots of clean and cleaner options at the substation (e.g., fuel cells, large batteries, etc.) and size based on what will fit in the substation footprint while leaving sufficient space available for turbines and reciprocating engines (layer 3a) to deliver

		the remaining load
3a	Deploy Dirtier IFOM Options at/near the Substation	• HVO or natural gas turbines or reciprocating engines that can be transitioned to RNG or hydrogen over time.
3b	Leverage Grid Services Assets	• Leverage DR, flywheels, and/or batteries for grid services (e.g., peak shaving, frequency regulation, inertia, fault current, etc.)

Temporal issues should be addressed in more detail in a 3-5 year strategy for mitigating the impact of PSPS with diesel alternatives. Some technologies are early in their commercialization, while others are ready for deployment at scale. Some technologies could be deployed for the 2021 wildfire season while others - particularly large-scale options beyond the substation - will likely encounter interconnection and permitting delays, even if the technology can be immediately procured at scale.

A limiting factor in choosing technologies is the variation among substations - not just in peak demand but also in load profile, available footprint, and gas infrastructure access. Given this heterogeneity, technology team planning should be optimized for one individual or type of substation, which could inform specific RFPs to seek technology combinations to support load pockets better than any individual technology by itself.

While this conceptual framework can help guide future analyses, the selection of technology "teammates" is outside the scope of this document and should rely on the technical expertise of PG&E's interconnection, procurement, and modeling groups (see next steps).

Critical Gaps

Many of the 15 technologies outlined have seen significant technological and cost improvements in the last 2-3 years. Enchanted Rock now offers natural gas engines that support black start requirements. Lithium-ion batteries have come down the cost curve so quickly that now batteries - not natural gas peaker plants - are setting the marginal price of electricity in parts of the country while 60% of residential solar installations now include batteries in California. And flywheels, which used to be only useful for 15-minute frequency response, can now be discharged for 4 hours of daily peak shaving.

These technologies could further increase their value to PG&E by moving down the cost curve, improving performance, and closing technical gaps. **For earlier stage technologies, contingent purchase orders[18] can encourage earlier-stage startups to develop their product to meet PG&E PSPS**

[18] ADL Ventures definition of a "contingent purchase order": a non-binding agreement which enables legacy sector companies to specify demand for a new technology in a clear and concrete manner, with the ability to quickly trigger binding purchases upon the appropriate commercial milestones being reached. The contingent PO provides forecast specificity and a strong expression of demand to the start-up, facilitating investor conversations while providing the corporate partner early option value on the upside of a potentially disruptive product.

requirements. In any case, the assessment, identification, procurement, and installation of earlier-stage technologies require significant time investments such that the required scale of a specific individual technology within a team may not feasibly be obtained by the 2021 PSPS season. Therefore, it is important to keep in mind that team rosters may have to change over time due to such limitations.

Moreover, **the critical gaps to the deployment of clean alternatives to diesel during PSPS have less to do with necessary generation and storage technology advances and more to do with operational and organizational constraints, policy shortcomings, business model ambiguities, and grid infrastructure shortcomings**.

Category	Gap
Organizational and Operational	• Pilots and demonstrations • DERMS staffing

Policy and Incentives	• Utility incentive structures vis-a-vis BTM assets
	• Demand-side management: shift/curtail load during PSPS, especially peaks
	  ○ Demand response
	  ○ Commercial base-load reduction
	• DER incentives
	• Liability

Grid Infrastructure	• Insufficient transmission capacity • Inverters • PSPS signaling (notification that the system is in PSPS) • DERMS • DER visibility • Communications during outages or PSPS
Developer Support	• Visibility into RA potential • Long interconnection process • Duration of temporary generation contracts
Customer Behavior	• Unknown customer availability/performance during PSPS, e.g., EVs

Organizational and Operational

Technology Pilots and Demonstrations: Even more so than other utilities, PG&E has significant bandwidth constraints that impair its ability to pilot promising technologies. Its electric operations teams have to be focused on solutions to address the next wildfire season and cannot be distracted by longer-term planning. During the roughly seven months of wildfire season every year, critical personnel may be pulled off their day-to-day jobs to support the Emergency Operations Center in drills and wildfire response. As a result, promising technologies cannot always be piloted.

For any of the solutions proposed in this document to be deployed, **PG&E must access a dedicated set of technical personnel and equipment to pilot promising technical solutions and accelerate the completion of interconnection studies**.

DERMS Staffing: **To incorporate distributed resources, PG&E will need dedicated technical operations staff above and beyond current T&D control centers to leverage a DERMS** (see below) to dispatch and control DERs. This is a specialized skill set for which there is a thin market for relevant talent.

Policy and Incentives

Utility Incentive Structures: While this gap may be less specific to PSPS, we would be remiss if we failed to note that utilities, in general, are not incentivized to promote BTM generation and storage. **PG&E employees are determined to do the right thing for their customers, but those decisions are often made in spite of, not because of financial incentives**. Islanded behind-the-meter solar and storage can significantly mitigate the impact of PSPS events on customers, but PG&E bears the risk that customers pay less for energy from the grid while the utility bears the full cost of the T&D investment. This puts further strain on customer rates, thus encouraging more defections.

Transition Incentive Structures: Multi-year contract structures with high availability payments, representing sunk costs once signed, and low performance payments would reduce the ability of cleaner technologies to compete for future contracted capacity. In relative terms, it would be more attractive to have lower availability payments and higher performance payments (even at total-cost parity) to better incentivize a future transition to cleaner technologies while maintaining sufficient resource availability. Moreover, any long-term commitments to fossil generation could limit future incentives available to cleaner technologies in RA markets. Therefore, **PG&E should be mindful of how any contracts signed for PSPS generation - especially multi-year contracts - could affect a transition to cleaner fuels**.

Demand Side Management: PG&E has moved from one extreme - power shutoffs without mitigation - to another extreme: substation generation such that some customers may not even know that PG&E is paying several times the customer's TOU rates to provide power during a PSPS. There is a policy (and enabling technology) gap given that there is neither a mandate nor a financial incentive for customers to curtail or shift loads during PSPS.

- *Demand Response*: **There is not yet a DR program unique to PSPS events**. While a demand response program that is designed uniquely for each substation may be prohibitively expensive, a PSPS TOU incentive or PSPS DR program could help incentivize behavior to lower the "head of the duck," for example, through residential or C&I programs for pre-cooling and curtailment of non-critical loads. Further study is required to evaluate the degree to which communications can be relied upon during PSPS (see Grid Infrastructure, below).

- *Commercial Baseload Reduction*: **There is no requirement for reduction in demand from commercial buildings, which could include the mandated closure of non-critical office buildings during PSPS events** (which would not be as unusual post-Covid as it would have been pre-Covid).

DER Incentives: **Customers with BTM batteries or other DERs are not currently incentivized to operate their storage devices any differently during a PSPS event than at any other time**. PG&E also does not have a program that incentivizes customers to offer batteries to reduce net load during PSPS events.

Liability: If batteries or other customer-owned assets used for PSPS mitigation caused fires or other malevents, PG&E liability coverage may be insufficient.

Grid Infrastructure

As outlined above, BTM assets can be the lowest-cost and most environmentally-attractive technologies to mitigate the impact of PSPS. **Several grid infrastructure gaps must be overcome for BTM assets to be used productively during PSPS events:**

Insufficient Transmission Capacity: Though the transmission system peak load exceeds 20,000 MWs, CAISO data suggests that only 478 MWs are available for new distributed generation, primarily due to transmission congestion. There are few serious proposals to significantly increase transmission capacity. **Resource Adequacy (RA) revenue, which could advance many clean generation projects and support California's goals of increased renewables penetration, is limited by transmission congestion. If they cannot cannot support the rest of the grid year-round, projects may require a higher PSPS incentive payment to be developed.**

Inverters: Many inverters installed before 2018 are designed to trip during an over-frequency condition (e.g., when generation exceeds demand), which can cause a cascading failure. **Older inverters need to communicate with PG&E and curtail to prevent damage to the grid.**

PSPS Signaling: **DERs cannot currently receive a signal informing them whether the system is in PSPS (or about to be in PSPS)**. As a result, DERs do not know when to island, pre-charge a battery, or respond to PSPS price signals.

DERMS and ADMS: **PG&E does not currently have a fully-functional DERMS, which is necessary for connectivity, grouping, and management of DERs in a PSPS event.** A DERMS would also be required to support islanding and coordinate multiple large and small resources. **A full ADMS solution with power flow, integrated with the DERMS, is also necessary to manage islanding at large scales.**

DER Visibility: **PG&E has limited visibility into the potential energy (e.g., charge) in batteries and other DERs.**

Communications during Outages: **Common DER communications methods, e.g., internet or cell phone towers, may not function in an emergency**. A different method of communicating with DERs may be required.

DER Integration Study: Sufficient study has not been done of power flow, stability, protections, and electrical systems to understand limitations and required operational processes. This would be appropriate for the National Labs, Fraunhofer, or another highly technical organization.

Synthetic Inertia Study: While there are many technologies capable of synthetic inertia, additional studies may be required on how to provide enough inertia for DERs to be a majority mix of the generation while leading to a stable island.

Private Developer Support

Uncertainty around a BTM development's revenue potential and impact on the grid increases the risk to a private developer. These delays and uncertainty make a project harder to finance because of factors external to the project.

Poor Visibility into RA Revenue Potential: **It is difficult for developers to prioritize their efforts with limited visibility into RA potential for specific locations.** This point is related to the transmission capacity point above.

Interconnection is time-consuming and risky: **While critical, interconnection studies often "reinvent the wheel" every time. The time-consuming, a risky interconnection process increases the expected cost of a project.**

Contractual terms provide insufficient certainty: PG&E currently has one-year rental contracts for diesel generators. To incentivize new generation to participate in PSPS, customers or developers will likely require a contractual commitment of at least five years, likely 10+.

Customer Behavior

Customer Performance: **PG&E has not sufficiently tested the behavior of customers with BTM assets in a PSPS to know whether they will perform as expected.** For example, it is unclear the degree to which EV owners would be willing to discharge their vehicles in an emergency or PSPS event. This, in addition to understanding auto OEM willingness to allow bi-directional charging, will be critical to evaluating the potential for EVs to contribute to PSPS mitigation.

Next Steps

This analysis primarily focuses on a single technology evaluation while alluding to the need to assess each technology as part of a "team." A future effort should analyze teams of technologies relative to each other and relative to the diesel incumbent solution.

We have outlined several ways in which optionality can increase the value of any particular technology, but have yet to quantify the real option value. This too would be a natural extension of this report.

Lastly, as outlined in the Executive Summary, this analysis is not intended to be prescriptive in any way. A future effort should leverage this analysis to craft a 3-5 year strategy to mitigate the impact of PSPS events. That strategy will likely hinge on addressing the critical gaps identified in this techno-economic analysis.

Glossary of Terms/Acronyms

AD: Anaerobic Digestion
BEB: Battery-Electric Bus
BESS: Battery Energy Storage System
BTM: Behind-the-Meter
C&I: Commercial & Industrial
CAISO: California Independent System Operator
CapEx: Capital Expenditure
CCA: Community Choice Aggregator
CO: Carbon Monoxide
CO2: Carbon Dioxide
CPUC: California Public Utilities Commission
DER: Distributed Energy Resource
DERMS: Distributed Energy Resource Management System
DR: Demand-Response
EV: Electric Vehicle
HVO: Hydrotreated Vegetable Oil
IBR: Inverter-Based Resource
IFOM: In-Front-of-Meter
kW: Kilowatt
kWh: Kilowatt-hours
LMP: Locational Marginal Price
MCFC: Molten-Carbonate Fuel Cell
MW: Megawatt
MWh: Megawatt-hours
NEM: Net Energy Metering
NFPA: National Fire Protection Association
NOx: Nitrogen Oxides
NREL: National Renewable Energy Laboratory
OEM: Original Equipment Manufacturer
OpEx: Operating Expenditure
ORC: Organic Rankine Cycle
PEM: Proton-Exchange Membrane
PG&E: Pacific Gas & Electric

PIH: Pre-installed Installation Hub
PM: Particulate Matter
PNG: Pipeline Natural Gas
PPA: Power Purchase Agreement
PV: Photovoltaic
PSPS: Public Safety Power Shutoff
RA: Resource Adequacy
RFI: Request for Information
RFO: Request for Offer
RFP: Request for Proposal
RNG: Renewable Natural Gas
SGIP: Self-Generation Incentive Program
SO2: Sulfur Dioxide
SOFC: Solid-Oxide Fuel Cell
T&D: Transmission & Distribution
TOU: Time-of-Use
V2G: Vehicle-to-Grid
VOCs: Volatile Organic Compounds

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