

# **Paired Storage Distributed Energy System**

## **Design for a Local Community Farm**

**Senior Project Presented to**

**Electrical Engineering Faculty of California Polytechnic State University San Luis Obispo**

**By**

**Neil Collison & Lily Goldman**

**Spring 2023**

# Table of Contents

<b>Table of Contents</b>	<b>2</b>
<b>Abstract</b>	<b>8</b>
<b>Acknowledgments</b>	<b>9</b>
<b>Intro</b>	<b>10</b>
The California Public Utility Commission's (CPUC's) Net Billing Tariff (NBT)	12
The CPUC and Its Bureaucratic Process	12
The CPUC's New Net Billing Tariff (NBT)	13
<b>Background</b>	<b>14</b>
City Farm's Current Electrical Agreements	16
Central Coast Community Energy (CCCE) and Community Choice Aggregation (CCA)	16
NEM 2.0: A Light Introduction	17
Transition to PG&E's NBT Schedules	20
Finding PG&E's NBT Schedule	20
PG&E's NBT Schedule's Relevance to City Farm	20
<b>Design Requirements</b>	<b>23</b>
Consumer Requirements Formal	23
Engineering Specifications	25
List of All Applicable Codes/Tariffs/Rules that we understand to be relevant	27
Existing System and Loads	31
Existing Service Type	31
Existing Service Size	34
Main Loads Electrical Specifications	37
PG&E Data	39
Future Load Estimation: The new building	40
<b>Design</b>	<b>43</b>
System Introduction: Type of Generation and Storage	43
Ballpark Amount of Generation/Storage	45
Functional Decompositions and Descriptions 0 and 1	50
PG&E's Rule 21 and NBT Schedule Specifics	54
Rule 21 Interconnection Review Process, Applies to All Considered System Configurations (Non-Export, Paired Storage, and Multiple Tariff)	54
Step 1: Applicant Initiates Contact with Distribution Provider	54
Step 2: Choose Review Process and Make an Interconnection Request	56
Step 3: Assuming Liability for Cost	58
Step 3.a: Cost Envelope Option	59
Step 4: Valid Application, Fast Track Review Process and AHJ Permit	60
Step 5: Finish Process	65
Intro to System Configuration and Subsequent Requirements	66
System Configuration: Non-Export	67

Define Non-Export System With Rule 21 Screen I	67
Non-Export and Option 8's Effect on Rule 21 Review	70
Non-Export and Billing	71
“Option” Analysis	71
Summary of Possible Equipment For Non-Export	72
System Configuration: Paired Storage	73
Definition of Paired Storage In Relation to Non-Export and Multiple Tariff	73
Potential Complications to PCC Metering	73
Defining Paired Storage with PG&E's NBT Schedule Special Condition 7	74
Paired Storage and Billing	81
Paired Storage Options' Analysis	82
System Configuration: Multiple-Tariff	84
Stay on NEM 2.0 by Separately Adding to Facility	84
Get on NBT-MT by Overstepping Paired Storage	84
NBT-MT Requirements	85
NBT-MT Billing	86
Potential CCA Hiccup With Multiple Tariff	86
PG&E NBT Schedule Aspects Applying to both Paired Storage and Multiple Tariff Equally	87
Confusion/Murkiness of Additional Metering Requirements	87
Warranty mandate	89
Generation Capacity Oversizing	89
General Mandates On Equipment	91
Rule 21 section Hh	91
Equipment Requirements Applying to Any Design	92
Title 24 Section 110.0	92
PG&E Rules 2, 3, 15 and 16	93
PG&E's Certification Requirements: Those Covered By California Energy Commission Solar Equipment Lists and PG&E Lists	94
PG&E's Certification Requirements: [Non-Export] Relays and Safety Switches	94
CEC: Approved/Listed Equipment	95
UL 1741, UL 1741 CRD, UL 1741 SA and UL 1741 SB and Final Thoughts on The Solar Equipment Lists	96
IEEE 1547-2018 (according to Rule 21)	98
Analysis on Choosing Non-Export, PS or MT	98
General Mandates Specific to Overall Design and Site Plans	101
Manual and Visible AC Disconnect	101
Harmonics	102
Rule 21 D.6	102
Greenbook Clearances	103
Bulk of PG&E Protection Requirements	103

Floodplain	104
Title 24 TABLE 130.5-B MINIMUM REQUIREMENTS FOR SEPARATION OF ELECTRICAL LOAD	105
<b>Site Plans</b>	106
CEC Sections Applying Generally	106
The Existing Renewable Solar Based System	108
2019 Installed Component List	108
Identifying Components' Locations and What Can Be Kept	109
Existing Site Plan and Demolition Plan	112
New Components, Their Locations and Motivations	113
Panels (solar)	113
Inverter/Control	119
Battery Aspect	120
GoodWe Inverter Features	122
GoodWe Transformers	124
Associated AC Disconnect	124
Electrical Paneling and Breakers (the protection system)	125
Backup Load	131
Battery	132
Inverter/PV	134
Conduit and Wiring	134
Grounding	136
Markings	138
One-Line Diagram and Conductor Table	139
<b>Simulation and Results</b>	140
Voltage drop calculations	140
Available Fault Current Estimation	142
Step 1) Determine full load amps of transformers	142
Step 2 and 3) Determine Let Through Short Current by Either Equation or Table	143
Bussman SC Calcs	143
Arc-Flash	145
Back-Up Capacity Analysis	146
<b>Conclusion</b>	147
Theoretical Bill of Materials	147
Expected Lifetimes and Warranty Accounting	148
Simple Financial Analysis	148
Articulate what goals were[n't] met	150
Recommendations for Future Work	151
<b>References</b>	152
<b>Appendices</b>	165
1)SLO Circuit Electrical Invoice	165

2) Equipment lists	166
3) Inverter Programing	166
4) Theoretical Forms	166
5) ABET Analysis	166

## Table of Figures

Figure 1. SLO City Farm's PG&E Bill for March 2023.....	16
Figure 2. SLO City Farm's PG&E Energy Statement for March 2023; CCCE Rates.....	17
Figure 3. SLO City Farm's PG&E Energy Statement for March 2023; PG&E Rate is NEM2M... Figure 4. Conditions where PG&E Requires Interconnection Request.....	19 21
Figure 5. 240/120 Delta 4-Wire Service and Associated Voltage Levels. Credit Control Systems LLC.....	32
Figure 6. 240/120 Delta 4-Wire Service Options.....	33
Figure 7. On Site PG&E Meter With Voltage and Service Type Called Out.....	34
Figure 8. PG&E Transformer Service.....	35
Figure 9. PG&E Usage Trends for 2021.....	36
Figure 10. PG&E Transformer with Rating.....	36
Figure 11. Power Received from and Delivered to PG&E; 01/01/2022.....	38
Figure 12. Power Received from and Delivered to PG&E; 05/01/2022.....	38
Figure 13. Power Received from and Delivered to PG&E; 09/01/2022.....	39
Figure 14. Simulation of system comparing demand to how much power is produced.....	42
Figure 15. Examples of Renewable Electrical Generating Facility.....	44
Figure 16.....	45
Figure 17.....	46
Figure 18.....	47
Figure 19.....	48
Figure 20.....	49
Figure 21: Level 0 Functional Decomposition.....	50
Figure 22: Level 1 Functional Decomposition.....	51
Figure 23. ICA Map, City Farm's Feeder Capacity.....	57
Figure 24. Rule 21 Table Summarizing Interconnection Request Fees.....	58
Figure 25. Flowchart of Rule 21 Review Process.....	61
Figure 26. Rule 21 Section Mm1.....	69
Figure 27. PG&E Rule 21 Min/Max Service Voltages.....	70
Figure 28. Integrated or Directly Connected Storage as per RPS Guidebook.....	75
Figure 29. AC vs. DC Coupled Systems as per the CEC.....	77
Figure 30. PG&E's Paired Storage Summary Table.....	81
Figure 31. Clearance Area Around PG&E Pole Mounted Service.....	103
Figure 32. SLO Circuit's Referenced Equipment.....	109
Figure 33. The Existing Backboard at City Farm and a Close Up on the PV Breaker.....	109
Figure 34. PG&E Drawing of Meter With Main Breaker Section and City Farm's Meter.....	110
Figure 35. The Existing Backboard at City Farm Noting Pump Boxes.....	110
Figure 36: Single Line of Existing (PV) Breaker.....	111
Figure 37. (On Left) Existing Equipment Site Plan and (On Right) Demolition Plan.....	113
Figure 38. Solar Panel Support Structure and Solar Panel String's Height/Area.....	114
Figure 39. Solar Panel Azimuth Angle.....	115

Figure 40. Solar Spacing Angles. Credit Greentech Renewables.....	116
Figure 41. University of Oregon Program's Solar Elevation at City Farm.....	116
Figure 42. Explanation of Azimuth Angle. Credit Keisan Online Calculator.....	117
Figure 43. Possible New Solar Panel String Locations at City Farm.....	118
Figure 44. New Solar Panel String Locations That Will Be Used, With Approximate Distance From Inverter To Main Breaker.....	119
Figure 45. Single Line Diagram For Our Design.....	139
Figure 46.....	149
Figure 47.....	150

## Table of Tables

Table 1. Customer Requirements for City Farms SLO Microgrid.....	23
Table 2. Specifications for City Farms SLO Microgrid.....	25
Table 3. 2022 PG&E Data.....	39
Table 4. Calculation of Future City Farm Loads' Power Draw.....	41
Table 5. Level 0 Partial Functional Decomposition Description Table.....	50
Table 6. Solar Module Partial Function Decomposition Description Table.....	51
Table 7. Battery Module Partial Function Decomposition Description Table.....	51
Table 8. Controller Module Partial Function Decomposition Description Table.....	52
Table 9. Protection & Switching Module Partial Function Decomposition Description.....	52
Table 10. Power Electronics Module Partial Function Decomposition Description Table.....	53
Table 11. Loads Module Partial Function Decomposition Description Table.....	53
Table 12. Conductor Wire Sizes and Lengths.....	139
Table 13. Smaller Electrical Equipment Bill of Materials.....	146
Table 14. Larger Electrical Equipment Bill of Materials.....	147

## **Abstract**

**This project considers the design of a renewable energy microgrid for a 19-acre community farm in San Luis Obispo, CA as the farm seeks to increase the magnitude of its electrical loads, and gain back-up electrical capability. The microgrid design will enable lower carbon emissions, reduce demand on the utility grid while saving on energy costs, and provide improved reliability and resiliency to the operator of the community farm. The eventual implementation of the design by a professional engineering entity will allow the community farm to expand its education program to include renewable energy as well as gain notoriety in the sustainability conscience community that City Farm relies on for donations. The design process will consist of 1) analysis of the farm's existing electrical system and its loads, 2) a dive into State, local, and utility rules defining under what circumstances microgrids can be built interconnected to the grid, 3) analysis to estimate optimal component and resource sizing, and 4) recommending locations, components, protection and component settings for the smart distributed energy generation facility 5) analysis on safety, back up capacity, and financial feasibility of the design.**

## **Acknowledgments**

Dr. Jason Poon

Steven Marx

City Farm SLO

SLO Circuit Electrical

Daniel Gerber

Thoma Electric

## Intro

With the plight of climate change set to increasingly menace many aspects of our daily lives, most industries are seeking options to reduce carbon emissions. One industry that is looking to reduce their carbon emissions is the agricultural industry. In California, the sector accounts for ~8% of greenhouse gas emissions. For this reason, agriculture has recently been in the news with innovative electrification ideas and government funding for farms to take advantage of renewable energy options. As agricultural machinery is successfully electrified, farms will have larger electrical loads that are more crucial to day to day operations. When tractors, cropdusters, and harvesters are electric (in addition to the typical electrical demands of the farm's water, storage and administrative facilities) farms will need a higher quantity of electricity, and they will be harmed to a greater degree if/when that source of electricity is cut off. This shift in the agricultural industry mirrors a shift across many industries, the residential sector and the broader electrical grid. Electrical loads are increasing.

Often as farms (rural ones in particular) electrify, traditionally electrical infrastructure is under developed and the loads being electrified are large, thus they often run into a constraint set by the utility service. [4,8,9] Utility upgrades are costly in terms of time and capital. [9] Many times to get around this farmers can operate diesel generators to supplement their electrical supply. This generation emits greenhouse gasses, which directly opposes a primary goal of electrification. [5] It also implies continuous cost that can fluctuate widely (see American gas prices in 2022). To accommodate this infrastructure bottleneck and take advantage of the modular nature of renewable electrical sources, electrical generation is widely becoming more distributed.

Micro grids below the 50kW size are becoming more common as the grid moves towards distributed energy resources (DER) [18, 16]. Even in the agricultural sphere such microgrids are gaining popularity. [18] Rural and agricultural areas with underdeveloped energy infrastructure have had great success electrifying via microgrids. [16] The components of such a grid have only become cheaper with time. Solar panels and batteries especially have decreased in price per kWh. [15,17] The United States local, state and federal governments all encourage green energy and agricultural electrification. Nonprofits such as Central Coast Community Energy (CCCE), have released substantial funds to facilitate the energy transition that can be (and have been) capitalized upon by those in the agricultural industry. The California Public Utilities Commission maintains a list of microgrid components ("solar equipment") with 1000s of pre-approved equipment modules. An increasingly feasible implementation is a microgrid that

generates, stores and distributes electricity to loads without demanding much power from the grid connection. [4,5,6,8] At a farm with energy sources from a mix of renewables and storage, the need for full dependency on the grid or back up natural gas generators will become less crucial.

## **The California Public Utility Commission's (CPUC's) Net Billing Tariff (NBT)**

As electrical loads, industry, and the grid all change, and new DERs get interconnected to the existing utility grid, there needs to be some kind of oversight to ensure that the changes made are beneficial to everyone and are properly incentivized. This is where our state of California deploys the California Public Utilities Commission, the CPUC.

### **The CPUC and Its Bureaucratic Process**

The CPUC is the regulating body for the California utility companies-- in the electrical field they facilitate planning and permitting for generation, storage, transmission lines and substations, they oversee environmental documents, and regulate electricity rates at the distribution level. [30] They have continuously analyzed and updated the regulations governing interaction customer owned generation and the utility grid/generation equipment, specifically regulating things like metering requirements, rates, fees, allowable systems and how these factors balance to move the grid and the state in the right direction (as described by federal bodies and according to their own analysis). [44, and CPUC's NBT] These regulations and rules (from what we can tell) are packaged into a unified mandating document called a tariff.

Since 2020 the CPUC has been in the process of analyzing and making changes to the current tariff prescribing rules for interconnection between utilities electric grid/power generation equipment and consumer owned/operated generation equipment [44, 46]. This is a long legal process wrapped in a rather complex bureaucratic formula which, at a high level, we understand to look like this: a proceeding is opened at the CPUC (in this case in response to a California Assembly Bill [44]), this begins the formal decision making process overseen by a CPUC judge and a CPUC commission/commissioner who issue rulings in order to communicate stakeholders ("parties"). These parties (utility companies, manufacturers, interest groups, public advocates ect) who can at specific times offer responses to a ruling, in the form of feedback, answers to questions posed, opinion, proposals, certain challenges ect. The back and forth culminates with a Proposed Decision that is open for comment and revision but eventually voted on by the commission in a public meeting whose ratification becomes a Final Decision.[44, 45] Although there can be (as is in this case) calls for further analysis and rule making. There can also be

calls for some parties to submit further documents (some are called advice letters which we will discuss further in section below, “Finding PG&E’s NBT Schedule”). [46, CPUC’s NBT]

## The CPUC’s New Net Billing Tariff (NBT)

This proceeding, about updating the tariff governing customer/utility generator interconnection, changes the old Net Electrical Metering tariff (NEM 2.0) to the new Net Billing Tariff (NBT). It passed its Final Decision (D. 22-12-056) in December 2022 and D. 22-12-056 (hereafter called the CPUC’s NBT) went into force on 4/15/23.[44, 46] We read through this 260 page document extensively, mostly because we thought we needed to (but also just a little bit for fun). We understand that CPUC’s NBT (D. 22-12-056) was adopted for some specific reasons:

- 1) To promote equity [CPUC’s NBT Section 3.b]. CPUC found that the NEM 2.0 tariff was negatively impacting customers who did not own their own generation equipment. [CPUC’s NBT Section 8.1.2] They, along with low income customers in general, were paying more as NEM 2.0 customers bypassed certain charges for infrastructure and other associated services, representing “a wealth transfer from lower-income to higher-income customers.” [CPUC’s NBT Section 8.1.3 and 8.1.4]
- 2) To incentivise customer owned/operated generation equipment to be more beneficial to the grid as a whole and other customers [CPUC’s NBT Section 3.g]. NEM 2.0 was not doing enough to incentivize customers to shift their energy usage to lower priced hours, instead of using electricity at high price times when the grid is under greatest demand. [CPUC’s NBT Section 8.4.3]. We understand this to say, when consumers are generating solar electricity for themselves they don’t use enough of it and PG&E pays them back for more than it could cost PG&E to buy it elsewhere but then when it is mostly too dark for their solar generation to meet their loads they (along with everyone else) demand more electricity. This is not all that beneficial of a situation for the grid to be in.

# Background

We have referenced industry, governmental and political environments that microgrids/DERs are being built in. But what exactly that means at the level of an individual farm has not been made clear. Nor have we made clear how our project fits into what we have thus far discussed.

During the planning phase of our project, we made contact with a local, non-profit community farm called City Farm SLO. They grow crops with the aid of volunteers and donors, while modeling sustainable agricultural practices. They provide farm land to local tenants. They operate as a teaching resource for local schools, who bring their students for farm based sustainability education. Both we, and the farm management agreed that sustainable energy is beneficial to City Farm; their passion about sustainable farming has come to include sustainable energy generation (they currently have ~4kW of solar panels installed). The location of the farm and its outreach to local schools offer a way to demonstrate and project the idea that DER microgrids are useful, and can inspire a next generation of engineers to apply themselves to improving our energy infrastructure.

We will aim to develop a design for a larger, more complex microgrid for City Farm's use. City Farm currently has a myriad of electrical loads such as: an electric tractor, water pumps, a refrigeration unit, HVAC loads, and lights. The loads that City Farm have are typical of many farms. Their electric water pumps are common if not yet ubiquitous on farms. The electric tractor is a developing market that is expanding. City Farm intends to build an additional structure to serve as a teaching/administrative/storage facility, so their electrical load will be increasing. Our work on this project will have some broader application to other farms in these respects, but locally, City Farm would enjoy cheaper electricity bills, enhanced electrical reliability, an expansion to their ability to teach about sustainable electricity, and enhanced notoriety in the sustainability conscious community.

Our system will generate power with solar panels and store that power in batteries before distributing it and use existing grid infrastructure as a back up. The generation capacity will not equal the total demand as all the loads will not often be at full usage at once. While they are, we will be able to drain power from the batteries. The trick will be to size the panels and the batteries such that we neither over generate or have inordinate amount of energy storage, but will always have the power to meet the demand and draw minimal power from the grid. [14,15] There is a supplemental consideration, how long can we power essential loads if the grid fails.

To accomplish this the site will be assessed for the possible DER's. Study of the wind and solar resources of the site combined with a comparison of the average monthly loads, provide the data needed to simulate a possible system for the farm. Simulations such as HOMER simulations are performed to obtain the optimal and cost-effective size of the microgrid system[19]. All steps taken to design a microgrid for City Farm SLO will emulate industry practices and use industry software and calculation methods.

We note though, that we are not a professional engineering firm. Our design will not be able to be submitted to the authority having jurisdiction (the AHJ) as we cannot sign and seal them as professional engineers. There will also be steps that we will not be able to perform. We will not make requests for information from the City as we are not undergoing a formal design process (we are not carrying out its formal requirements for meetings or design/contracting steps). We are not licensed to open up any of the existing electrical panels to attach or inspect equipment. We are also not in a position to pay PG&E the money to do a site visit and inspect all the existing equipment for us (their fees run ~2 or 3 times our budget for our end of the project). Therefore we will only be able to make educated guesses at some aspects of the design process. That being said, we feel confident that our design will be of significant value. The goal is that City Farm be able to hand over our documents to a professional engineering entity who enacts the project for them. Our documents and the motivations behind should offset a significant portion of the design time and thus save City Farm money in the design process.

## City Farm's Current Electrical Agreements

We find it prudent to start by trying to understand the monetary angle that is inherent to this project. Afterall, City Farm is unlikely to implement a design that is financially unfeasible. Key to the ability for City Farm to profit from their new DER facility is the method and rates at which they are charged/credited for electricity. We must understand their electrical schedule and how the CPUC, PG&E and CCCE influence it.

### Central Coast Community Energy (CCCE) and Community Choice Aggregation (CCA)

City Farms was kind enough to allow us to access their PG&E account. This held a wealth of information, including their billing history. Just one bill equipped us with the questions to ask about how City Farm pays for their electricity, what agreements they pay under, and to whom they make their payments. See Figure 1, page 1 of 4 of a recent bill.

 <b>ENERGY STATEMENT</b> <a href="http://www.pge.com/MyEnergy">www.pge.com/MyEnergy</a>	Account No: [REDACTED] Statement Date: 03/31/2023 Due Date: 04/17/2023
<b>Service For:</b> CENTRAL COAST AG NETWORK CALLE JOAQUIN SAN LUIS OBISPO, CA 93405	<b>Your Account Summary</b> Amount Due on Previous Statement \$121.41 Payment(s) Received Since Last Statement -121.41 Previous Unpaid Balance \$0.00 Current PG&E Electric Delivery Charges \$67.00 Central Coast Community Energy Electric Generation Charges 18.38
<b>Questions about your bill?</b> Agricultural Specialist available: Mon-Fri: 7am to 6pm 1-877-311-3276 <a href="http://www.pge.com/MyEnergy">www.pge.com/MyEnergy</a>	<b>Total Amount Due by 04/17/2023</b> <b>\$85.38</b>
<b>Ways To Pay</b> <a href="http://www.pge.com/waystopay">www.pge.com/waystopay</a>	

Figure 1. SLO City Farm's PG&E Bill for March 2023

Note that City Farms pays for its electricity to be delivered (payment to PG&E) and generated (from Central Coast Community Energy). This is because the City of San Luis Obispo recently entered into an agreement with a community choice aggregation program (CCA). CCA is a program where instead of sourcing power from PG&E, the residents of SLO, source power from a different entity, specifically with the entity Central Coast Community Energy (CCCE). [31]

CCCE is a community owned --not-- for profit agency that purchases/generates the power that PG&E delivers to consumers over the grid that PG&E maintains; PG&E is not responsible for generating or purchasing that power City Farm uses, they only charge for metering the energy flow and transporting it on the grid, while CCCE sets generation rates (according to CPUC mandates). [32] Both charge per kWh City Farm imports and both credit per kWh City Farm exports, but at different rates and including different fees. See Figure 2, page 4 of 4 of a recent bill.

<b>ENERGY STATEMENT</b> www.pge.com/MyEnergy		Account No: [REDACTED]																											
		Statement Date: 03/31/2023																											
		Due Date: 04/17/2023																											
<b>Details of Central Coast Community Energy Electric Generation Charges</b>																													
02/22/2023 - 03/22/2023 (29 billing days)																													
Service For: CALLE JOAQUIN Service Agreement ID: [REDACTED] ESP Customer Number: [REDACTED]																													
02/22/2023 – 03/22/2023																													
<table border="1"> <thead> <tr> <th>Rate Schedule:</th> <th>NEM AG-A1</th> <th></th> </tr> </thead> <tbody> <tr> <td>GENERATION - ON PEAK - WINTER</td> <td>66.000000 kWh</td> <td>@ \$0.17900</td> </tr> <tr> <td>GENERATION - OFF PEAK - WINTER</td> <td>82.000000 kWh</td> <td>@ \$0.06900</td> </tr> <tr> <td></td> <td>Net Charges</td> <td>17.47</td> </tr> <tr> <td>Local Utility Users Tax</td> <td></td> <td>0.87</td> </tr> <tr> <td>Energy Commission Surcharge</td> <td></td> <td>0.04</td> </tr> <tr> <td colspan="3">YOUR NEM BALANCE OWED IS \$0.00</td> </tr> <tr> <td colspan="3">YOUR GENERATION RELEVANT PERIOD ENDS 12/2023</td> </tr> <tr> <td colspan="3">FOR MORE DETAIL ON YOUR CCCE BILL, CALL US AT 877-455-2223</td> </tr> </tbody> </table>			Rate Schedule:	NEM AG-A1		GENERATION - ON PEAK - WINTER	66.000000 kWh	@ \$0.17900	GENERATION - OFF PEAK - WINTER	82.000000 kWh	@ \$0.06900		Net Charges	17.47	Local Utility Users Tax		0.87	Energy Commission Surcharge		0.04	YOUR NEM BALANCE OWED IS \$0.00			YOUR GENERATION RELEVANT PERIOD ENDS 12/2023			FOR MORE DETAIL ON YOUR CCCE BILL, CALL US AT 877-455-2223		
Rate Schedule:	NEM AG-A1																												
GENERATION - ON PEAK - WINTER	66.000000 kWh	@ \$0.17900																											
GENERATION - OFF PEAK - WINTER	82.000000 kWh	@ \$0.06900																											
	Net Charges	17.47																											
Local Utility Users Tax		0.87																											
Energy Commission Surcharge		0.04																											
YOUR NEM BALANCE OWED IS \$0.00																													
YOUR GENERATION RELEVANT PERIOD ENDS 12/2023																													
FOR MORE DETAIL ON YOUR CCCE BILL, CALL US AT 877-455-2223																													
<b>Total Central Coast Community Energy Electric Generation Charges</b>		<b>\$18.38</b>																											
<b>Service Information</b> For questions regarding charges on this page, please contact: CENTRAL COAST COMMUNITY ENERGY 70 GARDEN CT STE 300 MONTEREY CA 93940 1-877-455-2223 <a href="http://www.3cEnergy.org">www.3cEnergy.org</a>																													
<b>Additional Messages</b> Monterey Bay Community Power is now Central Coast Community Energy (3CE).  3CE is a community-owned public agency governed by board members who represent each community served. Sourcing electricity from clean and renewable energy resources, revenue generated by 3CE stays local and helps keep electricity rates competitive for customers, while also funding innovative energy programs designed to lower greenhouse gas emissions and stimulate economic development. 3CE serves customers in communities throughout Monterey, San Benito, San Luis Obispo, Santa Barbara and Santa Cruz counties. Visit <a href="http://3CEnergy.org">3CEnergy.org</a> or call (888) 909-6227 to learn more.																													

Figure 2. SLO City Farm's PG&E Energy Statement for March 2023; CCCE Rates

## NEM 2.0: A Light Introduction

City Farms was approved to have 12 solar panels installed in 2019. This puts them under the Net Energy Metering tariff the California Public Utility Commission (CPUC) enacted in 2016 (NEM 2.0).

This tariff applicable to City Farm, NEM 2.0, published by the CPUC, mandates that investor-owned utilities (IOUs), such as PG&E, compensate consumers who connect energy

generating infrastructure to their electrical services (such as solar panels), for the energy that consumers feed back into the grid. [28] Sometimes this energy fed back to the grid is called exported energy. Normally, consumers such as City Farms will remain, for 20 years, on the tariff in force (NEM 2.0) at the time when their generation equipment is approved for interconnection by the IOU (PG&E).[28,29] City Farm also has an agreement with CCCE who agrees to purchase the exported power back that falls under NEM 2.0 [33] and the same 20 year legacy time frame still applies. [28] For City Farm, this means they will be on NEM 2.0, with PG&E and CCCE, until 2039, barring extenuating circumstances.

We verify that City Farms is indeed operating in an agreement under the most basic portion of NEM 2.0 tariff, standard NEM 2, and not any other. As per the PG&E handbook on distribution interconnections, the generation facility (City Farm) must 1) have less than 30kW of generation capacity and 2) generation capacity must be PhotoVoltaic or wind powered. [43] Both are true in City Farm's case. Additionally, see Figure 3, page 3 of 4 of their bill below. Note that this is solely the PG&E portion of the bill. We see the delivery rate schedule is "NEM2M". This "M" at the end could be confusing. We believe that it refers to the "monthly" aspect of the rate schedule, as opposed to any other special NEM 2.0 schedule included in the most recent PG&E Electric Schedule Sheet [34]. As per Special Condition 2.f of PG&E's NEM 2.0 schedules [34], agricultural consumers must pay bills at the end of each monthly cycle. The other explanation for the mysterious "M" we considered was NEM2MT, which is for customers having a "multiple tariff facility," this would refer to consumers operating a generation device that exports energy to the grid under NEM 2.0 as well as a generation device that either does not export, or does not fall under NEM 2.0. [35] This does not describe the current situation at City Farm, where they have only photovoltaic generation that falls under NEM 2.0. An additional note, in some cases energy storage (such as batteries) paired with NEM eligible generating devices do not fall under NEMMT but instead under NEM Paired Storage or NEMPS.[35]



# ENERGY STATEMENT

[www.pge.com/MyEnergy](http://www.pge.com/MyEnergy)

Account No: [REDACTED]  
Statement Date: 03/31/2023  
Due Date: 04/17/2023

## Details of PG&E Electric Delivery Charges

02/22/2023 - 03/22/2023 (29 billing days)

Service For: CALLE JOAQUIN

Service Agreement ID: [REDACTED]

**02/22/2023 – 03/22/2023**

**Rate Schedule:** NEM2M

**Rate Description:** Net Energy Metering - Monthly

Net Charges	\$63.82
City of San Luis Obispo Utility Users' Tax	3.18

**Total PG&E Electric Delivery Charges** **\$67.00**

2019 Vintaged Power Charge Indifference Adjustment

## Service Information

Meter #	1009995358
Total Usage	148.000000 kWh
Serial	Z
Rotating Outage Block	50

## Additional Messages

From March 1, 2022 to February 28, 2023, the Wildfire Fund Charge is offset by \$0.00109/kWh to reflect excess funds from the Department of Water Resources (DWR) Bond charge. The Wildfire Fund Charge is also offset by an additional \$0.00084/kWh during this same period for excess funds from the DWR Power charge. These charges were included in your electric charges prior to 2021 and were related to bonds issued and energy provided to customers by DWR during the 2000-2001 California energy crisis.

*Figure 3. SLO City Farm's PG&E Energy Statement for March 2023; PG&E Rate is NEM2M*

But we will not further describe the rate and infrastructure mandates of NEM2 schedules here, as our project will move City Farms out of NEM 2.0 and to the new interconnection tariff that goes into force on 4/15/23.

## **Transition to PG&E's NBT Schedules**

### **Finding PG&E's NBT Schedule**

We read through the CPUC's NBT document in such detail because PG&E's website was bereft of any schedule including or detailed reference to NBT. We could only ever find links outlining schedules based on NEM 2.0. Meanwhile the CPUC's NBT included a clause in section 8.5 paragraph (2) that says that "all references to net energy metering requirements established in other decisions [NEM 2.0] will continue to apply to the net billing tariff unless explicitly altered by this decision." This led us to believe that we would have to interpret the majority CPUC's NBT and retroactively apply it to the most recent and most relevant NEM 2.0 schedulesPG&Ehad published, a truly daunting prospect that we were sure to do poorly. It was not until significant time had been spent understanding the CPUC's NBT that we were blessed with great fortune. While searching through the CPUC's library for a PG&E advice letter about an adjustment factor to be used to estimate cost savings, we happened upon a Tier 2 advice letter submitted to the CPUC byPG&Ethat outlined NBT schedules and was in effect.

Advice letters are documents submitted outside the CPUC's formal proceedings process by utilities to communicate or request things, to provide information or, in this case, to update utility documents that fall under regulation by the CPUC. [46] A Tier 2 advice letter does not go into effect until CPUC staff approves it. [47] We had happened upon a CPUC andPG&Eapproved schedule of the exact type we were looking for: NBT paired storage and/or multiple tariff.

### **PG&E's NBT Schedule's Relevance to City Farm**

If City Farms were to add any battery storage and replace/add solar capacity (more than either 1kW or 10% of the current generation capacity), as we are planning to do in this project, they would have to get approval from PG&E via an Interconnection Request Process [PG&E Rule 21 Ee: Tables Ee.1, Ee.2 and Ee.3]. These tables are presented in Figure 4 below.

**Table Ee.1 – Replacing existing equipment**

Description of Modification	Notification Required?	Interconnection request is required?	Proceed without PG&E approval?	Fee (See table E.1)
Replace equipment with exact same equipment type	No	No	Yes	n/a
Replace with "like-for-like," <sup>4</sup> where:	Yes	No	Yes	Modification Fee in Table E.1 <sup>1</sup>
1. system output does not exceed what is listed in the original interconnection agreement and 2. operating mode is not adjusted.	Increases nameplate capacity of the system, but which employ inverter power controls that limit the active power output to the inverter listed size in the original agreement.	Yes	No	Modification Fee in Table E.1 <sup>1</sup>
Replacement increases nameplate capacity to <100kw <sup>2</sup>		Yes	No	Modification Fee in Table E.1 <sup>1</sup>
Increases nameplate to >100kw and < 110% of original capacity		No	Yes	E.1 <sup>3</sup>
Replacing equipment such that the system capacity increases and no inverter power controls are employed to limit the active power output to the inverter listed size in the original agreement	No	Yes	No	E.1 <sup>3</sup>
All other scenarios	No	Yes	No	E.1

<sup>1</sup> See Modification Fees in Table E.1.<sup>2</sup> For projects increasing capacity to less than or equal to 100 kilowatt (kW), pending the creation of certification schemes for inverter power controls (software/firmware) to limit export (per D. 19-03-013, OP6).<sup>3</sup> "E.1" refers to applicable charges/fees in Rule 21 Table E.1 for a new application.<sup>4</sup> Like-for-Like is defined in Section C.**Table Ee.3 – Adding Storage or Capacity**

Description of Modification:		Notification Required?	Interconnection Request Required?	Proceed without PG&E approval?	Fee (See table E.1)
Adding storage capacity to an existing storage facility without changing inverter	Generator's maximum output based on its rated capacity <sup>1</sup>	Yes	No	Yes	\$0
	Generator's maximum output based on its operational profiles <sup>2</sup>	Yes	No	Yes	Modification Fees in E.1
Adding storage to an existing generating facility that does not have storage.		No	Yes	No	E.1
Adding such that system capacity increases and no inverter power controls are employed to limit the active power output to the inverter listed size in the original agreement.		No	Yes	No	E.1
All Other Scenarios		No	Yes	No	E.1

<sup>1</sup> If the Commission determines that a generator's maximum output should be based on its rated capacity (per D. 19-03-013, OP6).<sup>2</sup> If the Commission determines that operational profiles of systems should be used to determine system impacts D.19-03-013, (per OP6).**Figure 4. Conditions where PG&E Requires Interconnection Request**

The act of making that interconnection request will instigate a scheduled update to the newest interconnection tariff, NBT, enforced on 4/15/23 which will call for a request for a new Billing Agreement. [41, see also Rule 21 E.2.c and Ee.1] We also expect this addition will affect City Farm's agreement with CCCE, but we will address how credit/import rates will change and

CCCE's support for Paired Storage and Multiple Tariff facilities' in the section directly below:  
"PG&E's NBT Schedule's Billing and Application to City Farm".

We thought briefly that there could be a cutout for Net Electrical Metering Aggregation (NEMA) scheduled consumers, who could still do upgrades/installations after 4/15/23 and fall under the NEM 2.0 tariff. NEMA refers to consumers that operate NEM eligible devices across multiple parcels with multiple meters where all parcels are under owned, rented or leased by a single entity. [28, 36] This is common for agricultural operations with lots of land use [28,36], and we did not immediately understand that the use of the word "aggregation" here is different from the "community aggregation" discussed above (which again, refers to an entity that purchases or generates City Farm's electricity). We now know that City Farm definitively does not have a NEMA schedule.

1. We see their PG&E schedule in Figure 3 the PG&E bill above
2. City Farms rents to other entities, and is not the renter across multiple parcels
3. City Farms is served by only one meter

Therefore, upon the project's completion and a theoretically successful application to enact the project being made to PG&E, City Farm's agreement would be updated to one that falls under NTB instead of NEM 2.0 and the system we design must meet the requirements of such an NBT agreement.

# Design Requirements

## Consumer Requirements Formal

Table 1. Customer Requirements for City Farms SLO Microgrid

Customer Requirements	Engineering Specifications	Justification
1, 6	Is safe and has protection system for people and equipment	Fault protection systems are used for the safety of the main grid [24]
2	Cost savings significant enough to justify upfront cost	CPUC sets rate structures to with expectation that costs will be recouped by savings in ~9 years [85]
3, 4, 5	If/when grid is down, farm can run off of battery storage until grid comes back up	Power outages on the farm will affect the refrigeration of the produce and irrigation of crops [22]
2, 3, 4, 5	Sized to provide sufficient power to existing and new loads without aid from grid	CPUC/PG&E allow system to be sized to 150% of current electrical demand if new loads can be attested to. [85, 86]
6, 7	Located on plot already carved out of farm for existing solar panels	See google earth images of 1221 Calle Joaquin, San Luis Obispo

8	System can be approved by PG&E without longer than standard review or ongoing PG&E interaction	PG&E detailed studies are costly and so are PG&E testing for non-verified equipment. [87]
2, 3, 5, 7	Hybrid energy resources built of renewable generator, batteries, and grid	Successful hybrid systems include a battery and at least one renewable resource[21]
2, 3, 4, 5	Control system developed that reacts to varying load, generation, storage and grid conditions.	Based on efficiency normally for a multi load microgrid[20]

**Customer Requirements:**

1. Safe for all visitors, tennents, and livestock
2. Net financial benefit
3. Increase reliability of power
4. Supports Current and future loads
5. Reduce greenhouse gasses
6. Not detrimental to farm operations
7. Visible from freeway
8. Fast to enact with minimal PG&E interaction

## Engineering Specifications

Table 2. Specifications for City Farms SLO Microgrid

Parameter	Target	Tolerance	Risk	Compliance	Test
System Costs Recouped	10	3 years	Med	Max	Financial simulation
System Function Time Without Grid Support	48 Hours	12 hours	Med	Med	Pen/Paper Scenario + Algebra
Supports All Loads at Appropriate Voltage	100% Rated Voltage	5%	Low	Med	Voltage Drop Calculation
All faults cleared	All Fault Locations	Zero Tolerance	Med	Max	Short Circuit Calculations
Only PG&E Approved Equipment Used	All	Zero Tolerance	Low	Med	Equipment Datasheets and PG&E Documents
PG&E Detailed Review	Not Required	NA	Max	Low	PG&E Documents

In general, we aim to produce site plans that are of professional quality and can be permitted without much additional work being done by the professional engineering entity. This means that our plans meet PG&E standards and all code requirements. This will be impossible for us to test on our own, but we can potentially get a professional company to quality control our documents.

While we will aim for our plans to be as professional as possible, but again, they cannot be signed and thus cannot be turned in for any permitting or application process. For that reason we will include the following as a warning on all pages of our plans.

\*PLANS/DOCUMENTS ARE STRICTLY FOR PURPOSE OF ACADEMIC PROJECT, THEY ARE NOT TO BE USED AS BASIS FOR APPLICATION TO ANY AUTHORITY WITHOUT DUE DILIGENCE BEING DONE BY PROFESSIONAL ENGINEERING ENTITY WHO SCRUTINIZE PLANS UNDER ALL APPLICABLE CODES/RULES/DECISIONS AND COMPLETE ALL NECESSARY STEPS TOWARDS ANY APPLICATION. THIS WRITER LIVES IN FEAR OF

CPUC DECISION 21-06-026, D.18-09-044, AND D.20-02-011 AND DREADS CPUC BLACKLISTING THESE WRITERS OR THE CALPOLY INSTITUTION.

\*THIS REPORT IS AN ACADEMIC EXERCISE, CITY FARM HAS NOT FILLED OUT CALIFORNIA SOLAR CONSUMER PROTECTION FORMS AND ANY BUSINESS/FINANCIAL DECISIONS MADE ON THE BASIS OF INFORMATION PROVIDED HEREIN MUST BE DISCUSSED AND VERIFIED WITH A LICENSED PROFESSIONAL BEFORE BEING COMMITTED TO.

## **List of All Applicable Codes/Tariffs/Rules that we understand to be relevant**

Permitted renewable energy microgrid systems in the United States (and California specifically) must all meet certain conditions for reasons of safety, efficiency, ease of use, profitability and a host of other reasons. These conditions are set by national and state governing bodies and commissions, the utility company they connect to, and local authorities. The conditions applying to microgrid projects, that we are aware of, are described briefly below

- The CPUC's Net Billing Tariff (NBT) [85]
  - This 260 page document effective December 15, 2022, lays out regulations for Investor Owned Utilities' (like PG&E) rate schedules and motivations for those regulations. We read it in reasonable detail but now recognize that the PG&E Net Billing Schedule will be more specific to us as customers.
  - We understand this document to provide good background information on what the benefits are available to City Farm but also PG&E's grid and the state of California as we weigh design choices.
- PG&E's Net Billing Tariff (NBT) Schedules [86]
  - We understand this 60 page document, effective on March 1, 2023, to speak mostly about mandates for "interconnection agreements." It says, this kind of system implies this kind of two way power flow so you fall under this rate so you have this agreement with PG&E.
  - Specifically, the schedule lays out under what conditions a rate schedule will apply to a customer, what expenses/credits that customer will be liable/entitled to under that rate, how those expenses/credits will be tallied and the forms required to apply under a specific schedule with a specific agreement. All forms locateable at [95].
  - We understand its details to be rather important as we begin to design our project. The design must meet mandates of this document to be approved, and understanding and following its strictures will directly influence the monetary compensation City Farm will receive at the completion of the build.
- PG&E's Rule 21 [87]

- This ~300 page document, effective on Feb 28, 2023, speaks about the “interconnection application.” It describes interconnection, operating and metering requirements as well equipment requirements and certifications for those customer generation facilities connected to PG&E’s grid. It also has lots of rules about what requirements correspond to what kind of systems and thus has some overlap with the PG&E NBT Schedule.
    - While being published in 2023 after the CPUC’s NBT was published, and being the most up to date version we can find, this PG&E Rule 21 document refers only to “NEM” tariffs never using the acronym NBT. We will assume that when the document refers to NEM it also refers to NBT unless in cases where that assumption causes conflicts with PG&E’s NBT Schedule.
  - It also describes the process of the interconnection application in detail, including time frames, types of application and associated review processes.
  - We understand this document to also be very important. The design must meet mandates set out here to go forward, but also the better we design to the review process Rule 21 sets out, the less back and forth City Farm will be liable to do with PG&E, potentially saving lots of man hours and managerial headache.
  - There are many other PG&E Rules 1-29 that are occasionally applicable and important. We read through some of them in their entirety and others we just skim. We will mention them as we see them applying.
- PG&E Interconnection Handbooks and GreenBook [43, 66]
  - The PG&E interconnection handbooks are documents that, we understand, are ruminations on PG&E’s interconnection rules and tariffs (primarily Rule 21 and the NEM/NBT tariffs). We will reference them sometimes when we do not understand what the rules and tariff schedules are saying or when we are looking for additional information, but we see complying with those rules and tariff schedules as our primary concern.
    - There are specific short rules documents that link to that we will also reference as we see necessary.
  - The greenbook, we understand, is a document that was written for the purpose of explaining mandates for taking a new service from PG&E’s

transmission/distribution lines. We will similarly reference some aspects of the greenbook as we see them to be relevant to things we do not understand, but again the Rules and tariff schedules are our primary concern.

- Local San Luis Obispo County Codes
  - The county of San Luis Obispo adopts 12 code documents for buildings, the ones we see as relevant are:
    - California Building Code and is based on the 2021 International Building Code. This code has electrical provisions for emergency systems that we don't believe apply to our project and (from what we can see) otherwise directs readers to the mandates of the CEC.
    - The 2022 California Electric Code (which is based on the 2020 NEC)
    - The 2022 California Energy Code; also called 2022 Building Energy Efficiency Standards or known colloquially as "Title 24" are the relevant parts [57, 58]
  - The county code makes a few amendments to the above, mostly dealing with permitting administration
    - The only relevant amendment we see is in section 19.06.010.a which modifies CEC 230.70(A)(1)
  - There is expedited process outlined for renewable projects on rooftops which does not apply to us.
- Local San Luis Obispo Municipal Codes
  - Again the county adopts the 2022 California Building Code, this specifically calling out Appendix G for Flood resistant construction, which we will reference later.
  - The Municipality likewise adopts the 2022 CEC and 2022 Title 24 with a few amendments that do not appear worth attaching here.
- The 2020 National Electric Code (NEC) and 2022 California Electric Code (CEC) [92]
  - These are ~1000 page electric codes set out by the National Fire Protection Agency and adapted to California respectively. They provide all kinds of benchmarks or standards for electrical design/installations in order to ensure safety of people and property. The California version (of which 2022 is the most

recent edition) is very similar to the National one, but with some minor additions/changes in language; we the specific California is relevant to our project.

- The NEC/CEC is of the utmost importance (fire safety is no joke) and we understand that many aspects of the project will definitely be checked against the CEC by the authority that eventually approves the build permit (the City of San Luis Obispo).
- California's Title 24 [57]
  - This is the ~500 page document outlining energy efficiency requirements in California. We are not sure how relevant this is as we are not designing a "building" per se, but from what we understand perhaps building a "structure" (such as what we will mount solar panels) and the fact that the professional engineers would apply for a permit from the local authority make us liable to Title 24.
  - Here we will pick out the sections that we see as relevant to us because the vast majority of what is in this document we do not see as relevant; we read the Table 100.0-A "Application of Standards" to make us liable for sections 1000.0, 100.1, 100.2, 110.0, 110.11, 120.0, 130.5, and 141.0.
    - 100.0 is summed up in the Table 100.0-A Application of Standards we reference
    - 100.1 and 100.2 are definitions and means of certain calculations
    - 110.0 and 110.11 deals with equipment certifications which we will discuss in detail
    - 120.0 deals with building envelopes, ventilation, space-conditioning and service water-heating which is not relevant to us
    - 130.5 deals with
      - metering and voltage drop which, we understand to be mandated in more detail by PG&E and the 2022 CEC
      - Separation of electrical circuits, which we will discuss in detail
    - 141.0 describes which parts of 140.x apply to additions/alterations (we are not constructing new buildings instead altering/adding to electrical systems), from this we choose "prescriptive approach" and find that none of referenced sections besides 130.5 seem to apply to us.

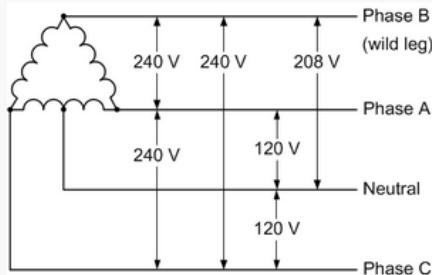
- Note especially 140.10 is specifically for new buildings and does not apply
- IEEE Standards
  - There are all kinds of IEEE standards, we pinpoint the, 140 page, IEEE std. 1547-2018 (Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces) [93] as being applicable here. It is referenced in Rule 21 and it is our understanding that Rule 21 is “harmonized” with it and takes precedence over it. However, Rule 21 also mentions “IEEE std. 1547-2018 and associated certification requirements being required.” [Rule 21 B.3 and B.5] We will apply these standards as we see gaps in Rule 21.
  - There is also the IEEE’s National Electric Safety Code (NESC) [94] which has provisions on overhead and underground power lines that make up “electric supply”. We understand this code to speak exclusively to mandates for utility companies “NESC rules do not cover: Utilization equipment or premises wiring located beyond utility service points to buildings or outdoor installations” [NESC 011.B.1] and we will thus not do more than a cursory examination of it.

## **Existing System and Loads**

### **Existing Service Type**

The current electrical service to City Farm, maintained by PG&E, is believed to be of voltage type: 240/120 delta 4-wire, also called a “high-leg” service. This is a three phase delta connected service, with one winding center tapped. The center tap line serves as a neutral, 120 volts between Phase A and Phase C (allowing standard one phase loads, like lighting, to be supported), while the three phase delta configuration still supports 240 volt load (such as an electric motor). [25] See below, Figure 5 for illustration of voltage levels.

**Three Phase Four Wire Delta**



*Figure 5. 240/120 Delta 4-Wire Service and Associated Voltage Levels. Credit Control Systems LLC*

We did not wish to contact PG&E or the City of San Luis Obispo directly about the parcel's service, as we did not want to instigate any kind of investigation into City Farm's operations. A previous senior project [26] similarly expressed hesitancy at inviting the City of San Luis Obispo into the process of their senior project and wanted to proceed with an abundance of caution for City Farms sake. We had no reason to believe that City Farms was out of compliance in any regard. When we did eventually attempt to obtain information from PG&E (detailed discussion in "Applicant Initiated Contact with Distribution Provider"), that seemed to be free to request under Rule 21 E.2.a, we were told that what we were looking for was only obtainable via a study that runs \$300-\$1200 (we think~\$900 for our case). We opted not to purchase a report that would have included this information.

But, we still have a solid foundation for our conclusion that City Farms has a "high-leg" service.

1. We were gifted with the single line and undergrounding wire routing document created by SLO Circuit Electrical (and ostensibly permitted by the City of San Luis) when that company designed the small solar installation constructed at City Farm in 2019. The single line diagram references that the "SERVICE CONDUCTORS ARE 240V DELTA 3-PHASE." It also mandates that "SUBPANELS SHALL BE FED FROM LINES A AND C ONLY @ 120/240." The language of "240v delta three phase" could potentially imply that City Farms has a three wire delta service, although we find that vanishingly unlikely for the following reasons.
  - a. The language of feeding sub panels from "lines A and C" is more typical of a high-leg service than a split phase one. In fact the NEC mandated that the "high-leg" line be called line B up until 2008 [see NEC 408.3(E) in 2005 edition];

thus “feeding lines A and C” for a split 120/240v 1 phase circuit (as seen in the SLO Circuit Electrical plans) makes sense from a nomenclature perspective.

2. PG&E’s Rule Number 2 describes the types of service that can be offered to consumers. This is the current Rule and is referenced by the rate schedule (AG-A1) that is applied to City Farms. Rule 2, Section B.1 includes the following table, which we depict in Figure 6. There are two 240 volt three-phase possibilities but the 3 wire option is described as having limited availability.

Distribution Voltages			Transmission Voltages
Single-phase Secondary	Three-phase Secondary	Three-phase Primary	Three-phase
120/240, 3-wire	240/120, 4-wire	2,400, 3-wire*	60,000, 3-wire
120/208, 3-wire	240, 3-wire*	4,160, 3-wire*	70,000, 3-wire
	208Y/120, 4-wire	4,160Y/2,400, 4-wire*	115,000, 3-wire
	480/3-wire**	12,000, 3-wire	230,000, 3-wire
	480/277, 4-wire	12,000Y/6,930, 4-wire*	(T)
	480Y/277, 4-wire	17,200, 3-wire	(T)
		20,780, 3-wire	
		20,780Y/12,000, 4-wire	

\* Limited availability, consult PG&E.

\*\* This service is no longer available for new or rebuilt installations.

(N)

*Figure 6. 240/120 Delta 4-Wire Service Options*

3. City Farm has a three phase water pump that requires either 230v or 460v lines to feed it (the reduction by 10v from 240v is to account for line losses from service to motor location). But it also has many 120v loads and receptacles. In light of the above PG&E Rule Number 2, no other configuration would make sense to service these loads.
4. Upon further site visit, we locate a tag seeming to confirm this on PG&E’s meter see below Figure 7 of PG&E’s meter at City Farm.



**Figure 7. On Site PG&E Meter With Voltage and Service Type Called Out**

Because of CEC 250.20 (B)(3), and 250.26(5), we are confident that the neutral wire is grounded. 250.20 says “Where the system is 3-phase, 4-wire, delta connected in which the midpoint of one phase winding is used as a circuit conductor” the neutral wire will be grounded. What a circuit conductor means is not directly defined, but we understand it means that the neutral terminal has a conductor connected to it that runs out to electrical panels and is used to conduct electricity. This is our case, we have electrical panels with a neutral line running to them and have loads utilizing 120v which is only possible if the neutral line carries current back from the line 120v above it.

## Existing Service Size

Now, to determine the size of the service. Again, PG&E could get up on the pole to look at the transformers and give us a definitive answer, but we were not willing to pay them the \$900+ to do so. But this is still an important consideration as we choose the basic form of our system, as we size our components and as we validate our detailed system design for safety.

Again referencing PG&E Rule 2, we find that section D.2.a refers to services sizes available from the secondary side of a three phase set of PG&E transformers which deliver power at

voltages below 2000v. Picking out our 240/120v service, we read the table to say that a 5 hp three phase load is the minimum load that requires PG&E to install a three phase service at this voltage level; we do not read it to say that the 5 hp three phase load will justify a 75kVA transformer for our service. City Farm happens to have a 5 hp water pump and it thus seems to follow that PG&E services City Farm via a three-phase set of transformers rated at least above  $5\text{hp} * 745\text{w/hp} = 3.7\text{ kw}$ .

<u>Nominal Voltage</u>	<u>Minimum Load Requirements</u>	<u>Maximum Demand Load Permitted</u>	
a. Secondary service normally available from overhead primary distribution systems (this may require the installation of underground primary to supply a transformer at ground level.):			
208Y/120	Demand load justifies a 75 kVA transformer	1,000 kVa	(T)
240*	5 hp, 3-phase connected	300 kVa	—
240/120	5 hp, 3-phase connected	300 kVa	—
480	30 kVa, 3-phase demand	3,000 kVa	—
480Y/277	30 kVa, 3-phase demand	3,000 kVa	(T)

*Figure 8. PG&E Transformer Service*

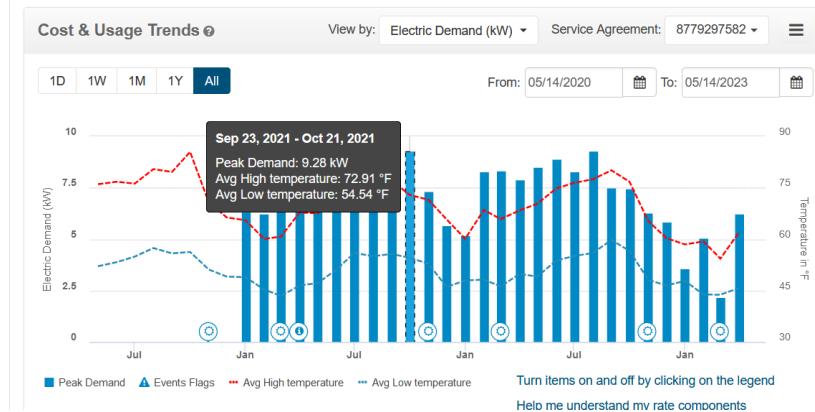
City Farm's meter, it is rated to 200 amps at 240v on a 3 phase delta system, if there was a 75kVA rate transformer, it could put out ~180 amps. This can be calculated with an equation for three phase transformers: [68]

$$\text{transformer power} = \text{rated voltage} * \text{rated current} * \sqrt{3} \quad (\text{eq.1})$$

The same 180 amp rating arrived at in multiple tables (one of which is found in a Benha University sheet which we will use later to assist us on the Point-Point method of calculating short circuit current [65]).

So we are confident that the service is not above 75kVA. But if the transformers were rated to that much power, we would struggle to reconcile this with the load data that we have from PG&E. A cursory glance indicates that at no time in the last three years (after the existing solar panels City Farms has were installed) has the peak demand gone above 10 kVA, see below Figure 9. Even without the offsetting ~4kW of solar that City Farms has, their loads seem to only represent (very roughly) about 14kW. There is a billboard with lighting that seems to be

connected to the same group of pole mounted transformers as City Farm's meter. While this could be a significant load on the transformer that we cannot see, it seems very unlikely that the billboard load is worth ~40-60 kW.



*Figure 9. PG&E Usage Trends for 2021*

We later came to the conclusion that the “25” printed on all the pole mounted transformers serving City Farm (see below Figure 10) likely indicated that they were rated to 25 kVA [72]. This fits much better with our understanding of the magnitude of City Farms loads.



*Figure 10. PG&E Transformer with Rating*

We also find it likely that during the previous solar installation, Rule 21 screen F was passed. This would imply that the ~4 kW of solar installed is less than 20% of the total transformer rating, further implying that the service transformer rating is greater than 20kW.

While we will operate under the assumption that the service to City Farm has a set of transformer[s] rated to 25kVA that feed the site (and an adjacent billboard) , we see this assumption as being based on slightly unstable ground. Although we are very confident that the service is not greater than 75kVA, because of the meter rating. The meter rating be larger than the service actually is, the meter rating has nothing to do with protecting the site so oversizing it has no negative consequences besides cost, which shouldn't be much of a consideration as meters are more of a one size fits all situation compared to transformers and we understand this kind of meter to be a PG&E standard one. So the meter does not rule our the 25kVA assumption.

The 25kVA seems to fit reasonably well with a rough estimate of load demand and we believe that Rule 2 allows for a 120/240v three phase system of that size.

We will stick with the 25kVA number in theoretical safety calculations, but again do not have certainty about the 25kVA number and as much as possible will not use it to justify design considerations.

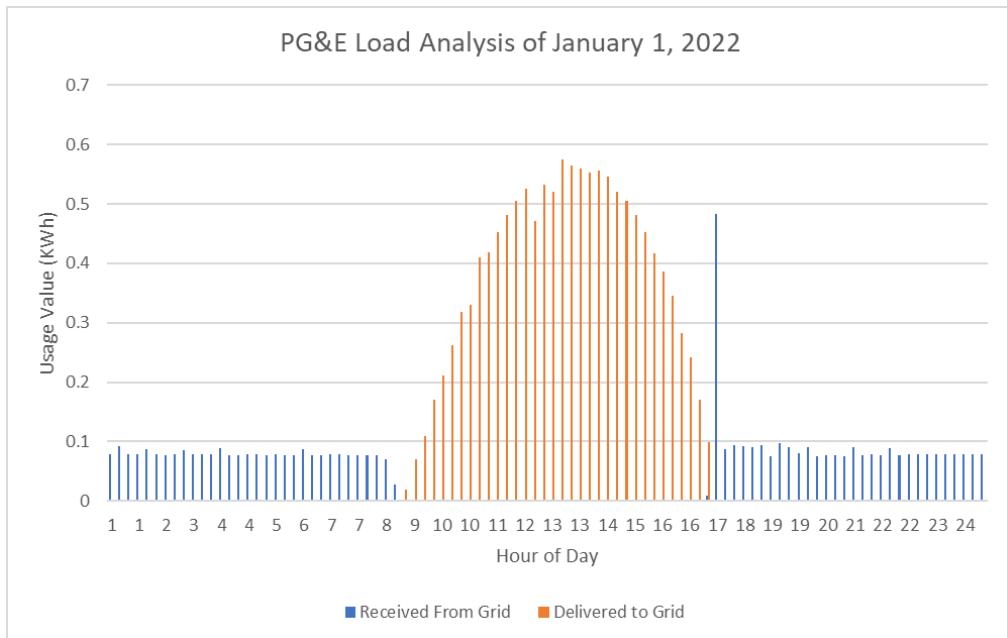
## Main Loads Electrical Specifications

Using the electric load data provided by PG&E, we are able to make assumptions on the power draw on their consistently running loads and the amount of electricity they use during the day. The main loads on the farm that are always running are the water pump and the refrigeration unit. After analyzing the load analysis of all of 2022, also illustrated in figures 11, 12, and 13, is a consistent 0.104KWh draw during the hours of 6pm and 8am. It can be assumed that the pump and the HVAC draw 0.104KWh.

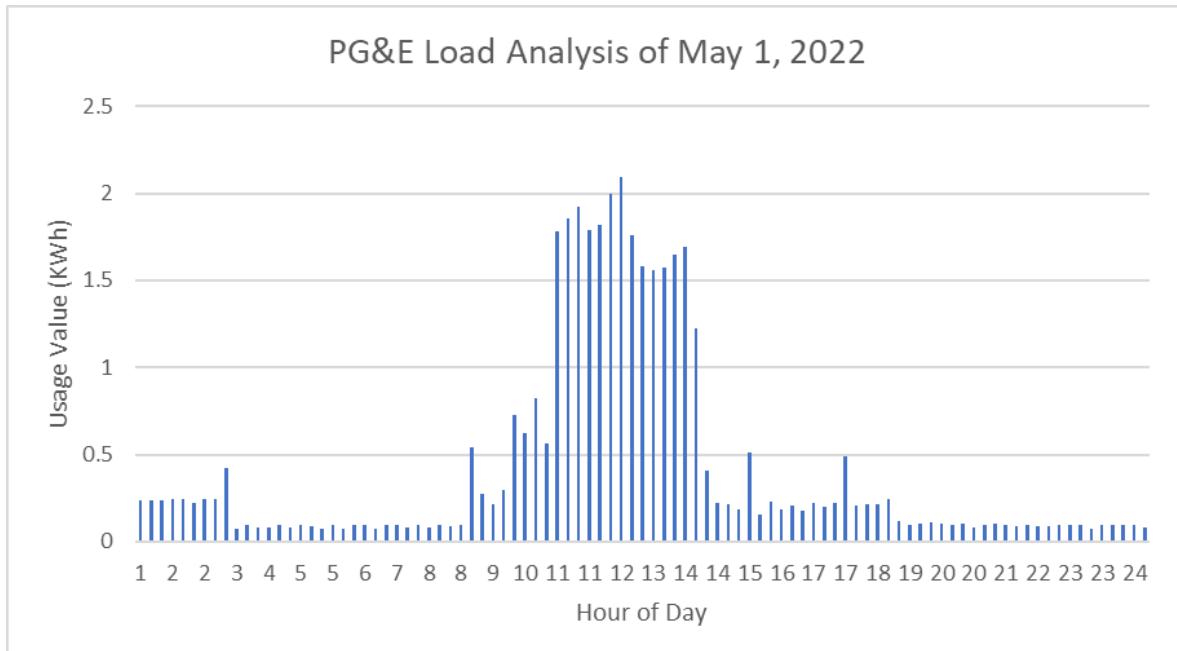
Another note is the electric tractor they have on the farm. We do not know how often it is in use and when they normally charge it. They do not have a specific charging station that has DC fast charging, so they plug in the tractor to a typical outlet on the farm to charge. Calculations for power draw of the tractor are included in the collection of data found between higher demand times on the farm such as between 8am and 6pm.

The rest of the loads are consolidated with regular use devices such as lights, powertools, and everyday household items used by the 5 tenants on the farm. Regular bell

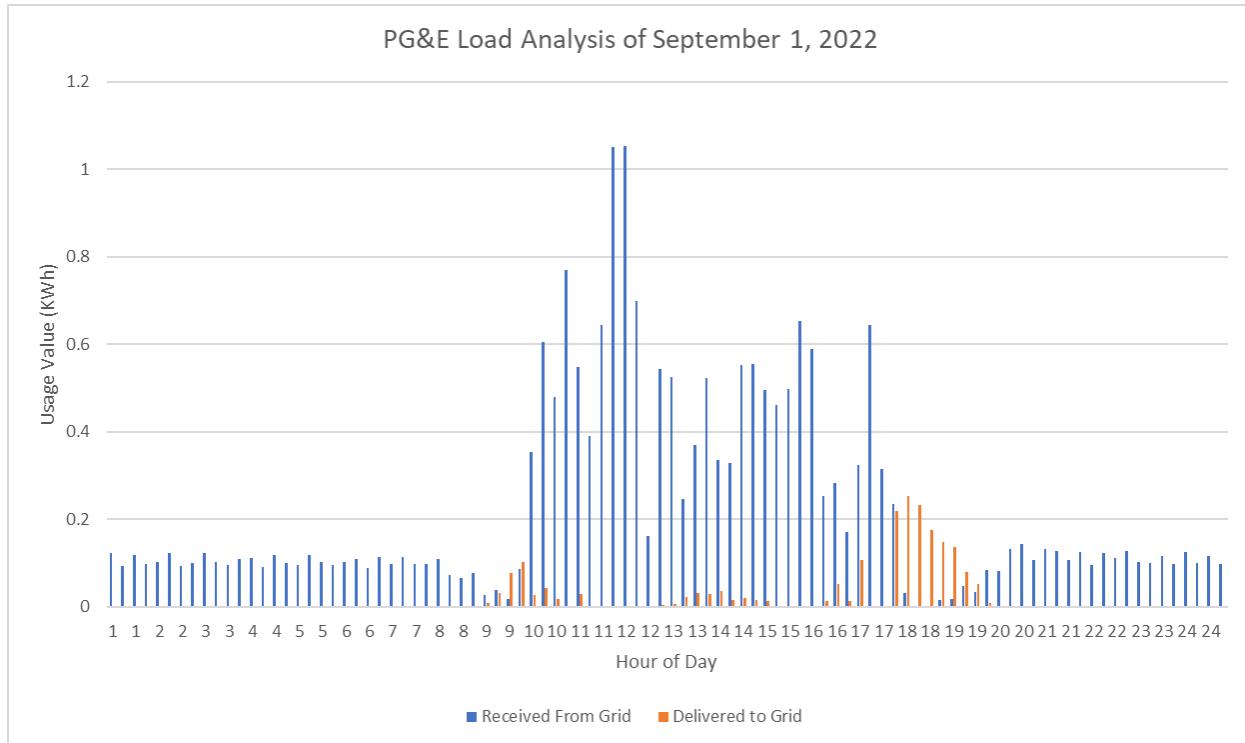
curves, as seen in figures 11, 12, and 13, represent daily electrical use on the farm in the winter, spring, and fall.



*Figure 11. Power Received from and Delivered to PG&E; 01/01/2022*



*Figure 12. Power Received from and Delivered to PG&E; 05/01/2022*



*Figure 13. Power Received from and Delivered to PG&E; 09/01/2022*

## PG&E Data

City Farm has 12 330W solar panels that take any excess power not used by the loads and sends it to the grid. The average power generated in 2022, reflected in Table 1, is how much of the generated power from the panels is sent back to the grid. Average power delivered is how much the loads on the farm are drawing from the grid.

**Table 3. 2022 PG&E Data**

Month	Average Power Delivered	Average Power Generated	Unit of Measure
January	0.152057	0.069	KWH
February	0.39566	0	KWH
March	0.296601	0	KWH
April	0.41706	0	KWH
May	0.481047	0	KWH

June	0.479647	0	KWH
July	0.504191532	0	KWH
August	0.366363	0.034656	KWH
September	0.243596	0.064343	KWH
October	0.276573	0.059139	KWH
November	0.169835	0.072399	KWH
December	0.1	0.05	KWH

It is expected that the average power would increase in the middle of the year as the temperatures increase and harvesting is done. This was consistent amongst all years of tracked data which includes the end of 2020, 2021, 2022, and the beginning of 2023.

The current solar and load system was simulated on NREL's System Advisory Model to compare the given PG&E data and how it will follow later simulations done on an upgraded system. Comparing the generated power in Table 1 and the simulated graph in figure[], it is found that the system sends more of its generated to the grid than could be used for the loads on the farm. Only January should have excess solar production. PG&E data illustrates that months of August through December have values of average power generated similar to January. This is understood in the load analysis graph of September 2022, figure [], with the power generated and received from the grid being intertwined during the same hours of the day. This means that not all solar production is going straight into the loads.

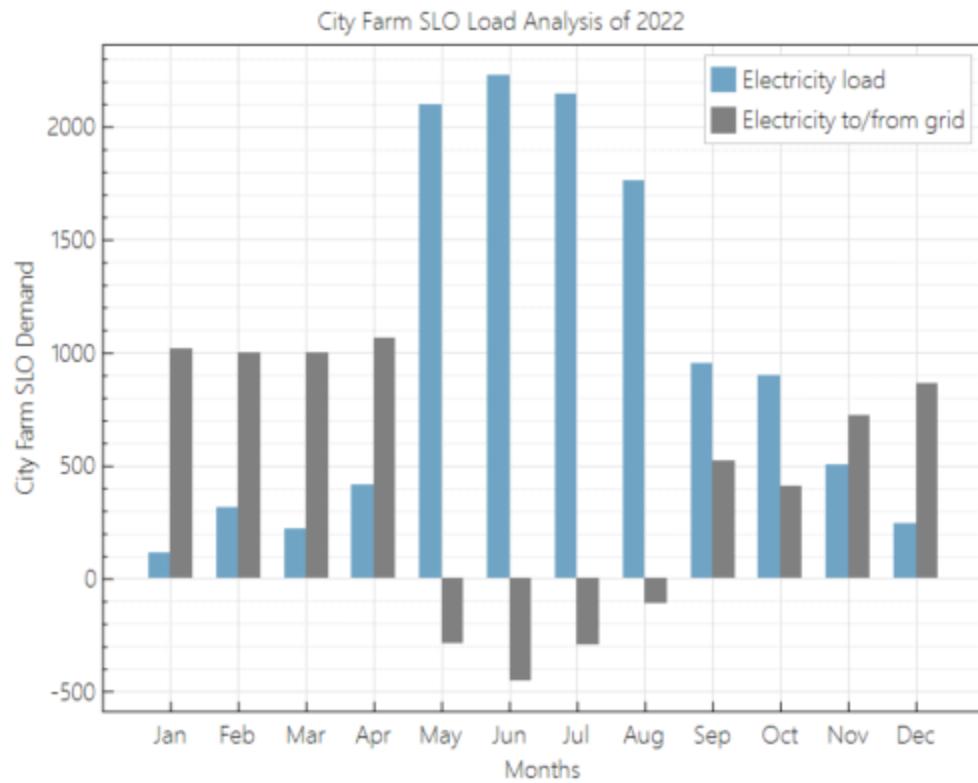
The purpose of the project is to decrease electricity bills and increase the amount of renewables used in the system and overall the farm. The incorporation of battery power would store the excess generation and allow for the farm to use willingly on and off peak load times.

## Future Load Estimation: The new building

After speaking with City Farm SLO, we got a better understanding of the different types of loads that they would eventually have to account for the increase in electricity bill. They are planning on building a large barn in the next 2 years that would be used as office space and teaching room for the community. The expected new loads include: lights, HVAC, dehumidifier, ventilator, and miscellaneous receptacles like computers and printers.

Table 4. Calculation of Future City Farm Loads' Power Draw

Type	Amount of	Max power draw of 1 unit(w)	total watts(W)	USE COEFFICIENT	Actual watts(W)
lights	14	90	1260	0.5	630
HVAC	1	3800	3800	0.5	1900
dehumidifier	1	700	700	1	700
ventilator	1	200w	200	1	200
12" Chop Saw size power tools	2	1800w	3600	0.01	36
Hand drill sized battery charger	3	140w	420	0.01	4.2
computer	2	610w	1220	0.5	610
printer	1	400w	400	0.01	4
monitor	2	30	60	0.5	30
refrigerator (small)	1	70	70	1	70
coffee machine	1	800w	800	0.01	8
misc receptacles	2	1200w	2400	0.01	24
				Total Demand:	
					4216.2



*Figure 14. Simulation of system comparing demand to how much power is produced*

# Design

## System Introduction: Type of Generation and Storage

The system we design will be renewable generation and include some way to store electricity for later use and back up. Within those parameters there are lots of possibilities. What will we generate with? How will we store energy?

Of the listed PG&E defined renewable energy generation facilities (RGEFs) eligible for NBT scheduling (shown below) [PGE NBT], we decided that photovoltaics was the best available option. Some of these are obviously unworkable, such as ocean, and tidal facilities, landfill gas, municipal solid waste conversion and geothermal. Producing and using digester gas seemed to require both larger scales of production than City Farm was capable of supplying and equipment/expertise that is not widespread in America. [50] We discount biomass for similar reasons of scale of available biomass inputs on the farm. We briefly considered attempting to set up a small hydro-electric system to store energy without using batteries, but this seemed only to over complicate the design without taking advantage of any CPUC/PG&E incentive. On a personal scale, we understand solar thermal to be about heating water for hot water use or air for interior heating use, [51] neither use would offset significant cost for City Farm nor allow them to store energy for backup. Previous studies done for City Farm determined that the site was not suitable for wind farming. It was communicated to us by the farm's administrators, that in addition to not having consistent enough wind on the site, large residential projects have recently been built or are planned in the surrounding area both of which led them to discount significant wind production. This author thinks hydrogen fuel cells are super cool.

For City Farm's application there is the potential to import hydrogen for generation or combine hydrogen creating electrolysis with hydrogen fuel cells to store electrical energy in hydrogen, instead of using a battery. [52] But we didn't see a system that needed regular input of fuel as what City Farm was looking for. But a less murky reason to discount continuous charge/discharge storage into hydrogen fuel cells, in favor of traditional batteries, is ease of use in design. The California Energy Commission (another governing body for California's energy policy) maintains a list of approved batteries and energy storage systems that are verified to meet national safety and performance standards. PG&E's NBT (sheet 21 paragraph 4) specifically calls out this list as documenting equipment that will meet Rule 21 certified equipment standards and will thus require no additional verification to use. This list has +1000 Energy Storage Systems and nearly 200 batteries listed, but no Energy Storage Systems

mentioning hydrogen in their description. To use a device not on this list exposes us to more risk as designers, will need additional verification [PGE's NBT Schedule sheet 21] and could imply additional PG&E review, all things we want to avoid.

#### **Renewable Electrical Generating Facility (REGF)**

A REGF means a generating facility that generates electricity by using:

- a) biomass,
- b) solar thermal,
- c) photovoltaic,
- d) wind,
- e) geothermal,
- f) fuel cells using renewable fuels,
- g) small hydroelectric generation (but a small hydroelectric generation facility is not an eligible REGF if it will cause an adverse impact on instream beneficial uses or cause a change in the volume or timing of streamflow),
- h) digester gas,
- i) municipal solid waste conversion,
- j) landfill gas,
- k) ocean wave,
- l) ocean thermal, or
- m) tidal current,

*Figure 15. Examples of Renewable Electrical Generating Facility*

We therefore choose to go with the most mainstream generation and storage types: photovoltaic generation and traditional battery storage. This makes the design, review and permit process the most straightforward and thus most likely to be timely as City Farms embarks on the actual building of the system. It lets us choose from a plethora of components as opposed to choosing from devices made by just a few manufacturers. This not only implies reduced cost but better customer service and device documentation, something that will be very important to inexperienced designers. This is in addition to all the reasoning articulated above.

We want to note that moving forward we will use REGF, NBT-Eligible facility and Photovoltaic/Solar System somewhat interchangeably.

## **Ballpark Amount of Generation/Storage**

To maximize power production and minimize cost of the system, a hybrid battery and solar resource design was developed for City Farm SLO.

How I did it:

### **- Monthly Load Summary**

These monthly and annual values are calculated from the hourly or subhourly load profile and shown here for reference.

	Energy (kWh)	Peak (kW)
Jan	117.00	0.29
Feb	313.00	0.86
Mar	222.00	0.62
Apr	418.00	1.49
May	2,100.00	7.26
Jun	2,230.00	7.84
Jul	2,145.00	5.79
Aug	1,762.00	5.31
Sep	955.00	3.45
Oct	900.00	2.74
Nov	505.00	1.35
Dec	247.00	0.63
Annual	11,914.00	7.84

*Figure 16.*

- I inputted values from past PG&E data from 2022 with all values multiplied by 1.5 to meet the 50% load increase
- Peak values were auto generated
  - The maximum load value that occurs each month
- It is the total electric mode for each month

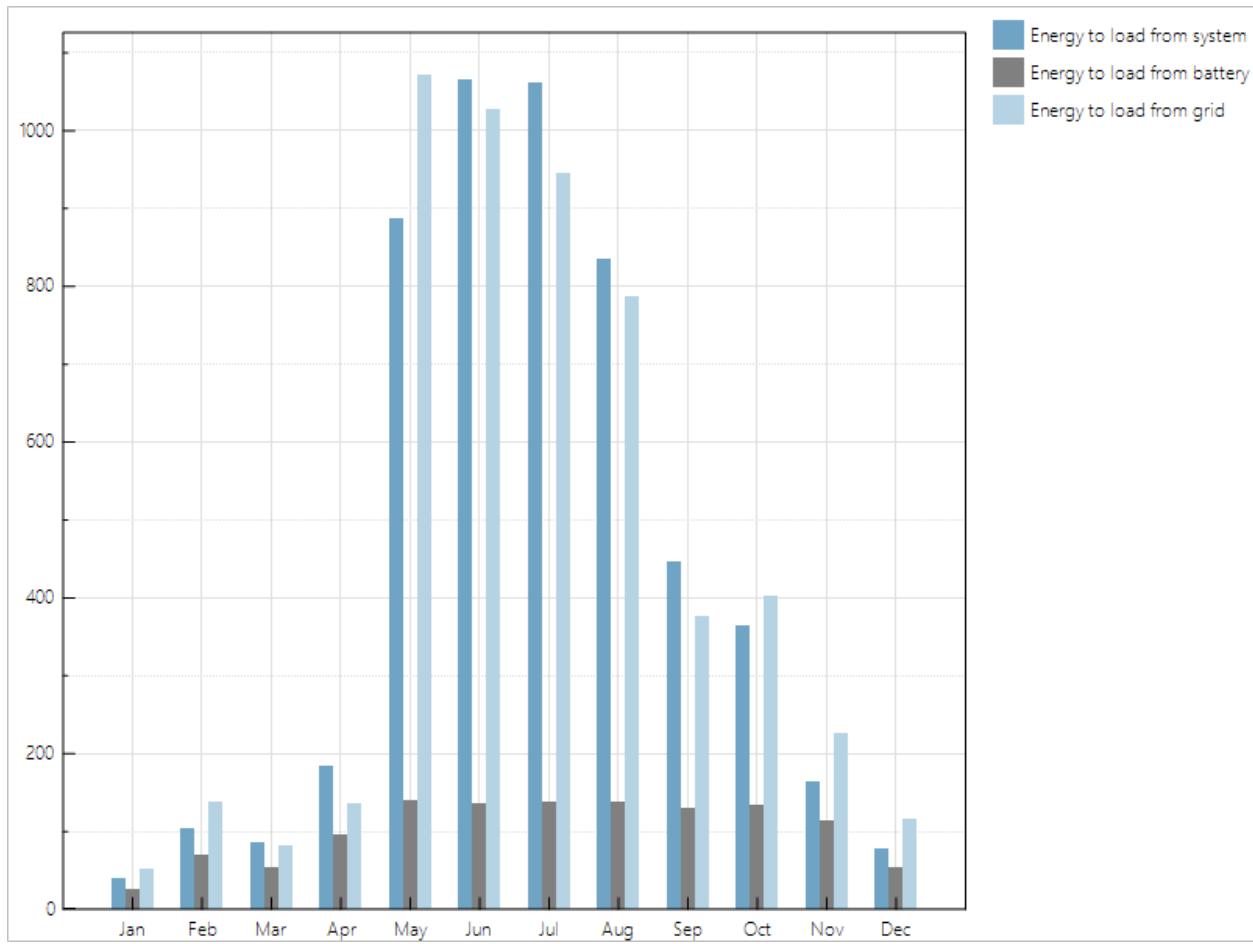


Figure 17.

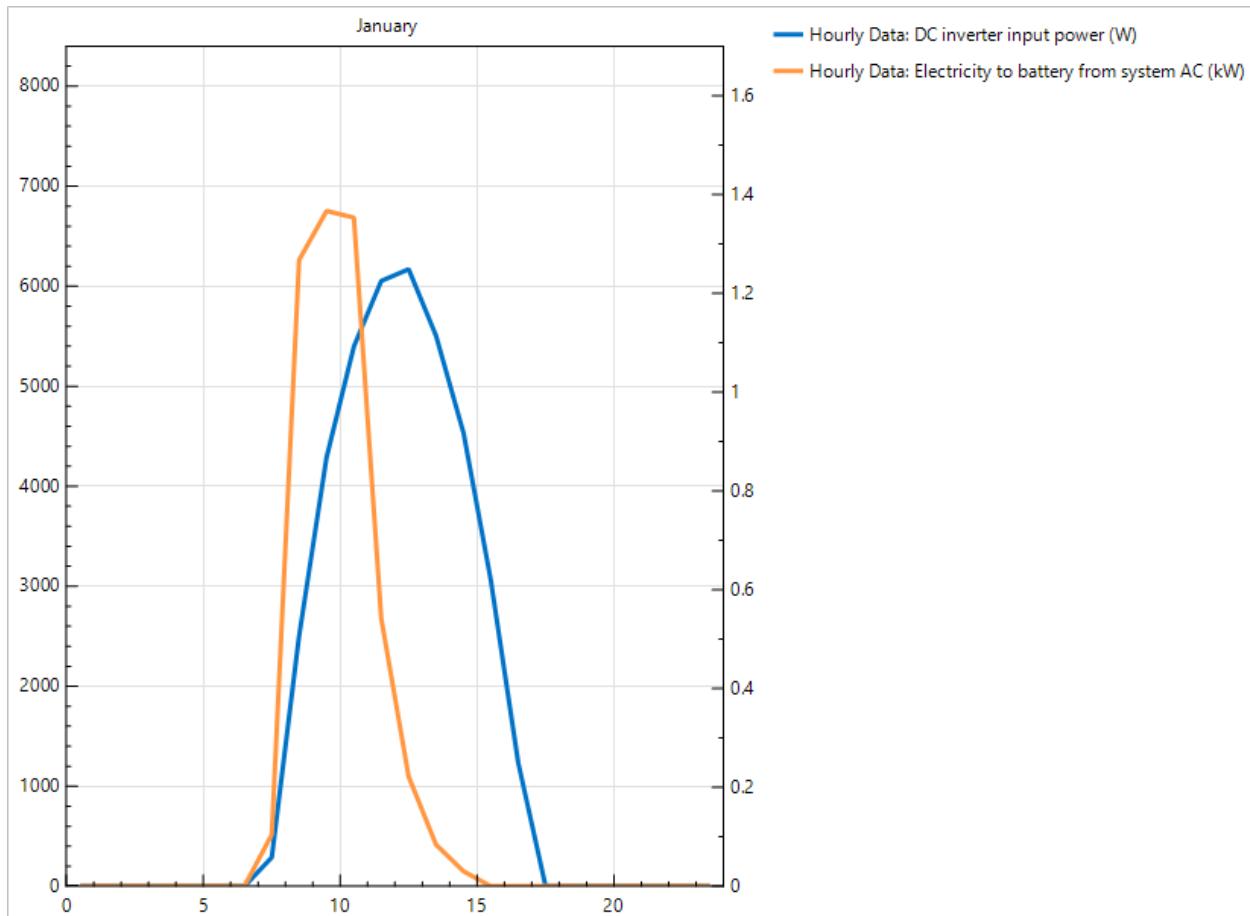
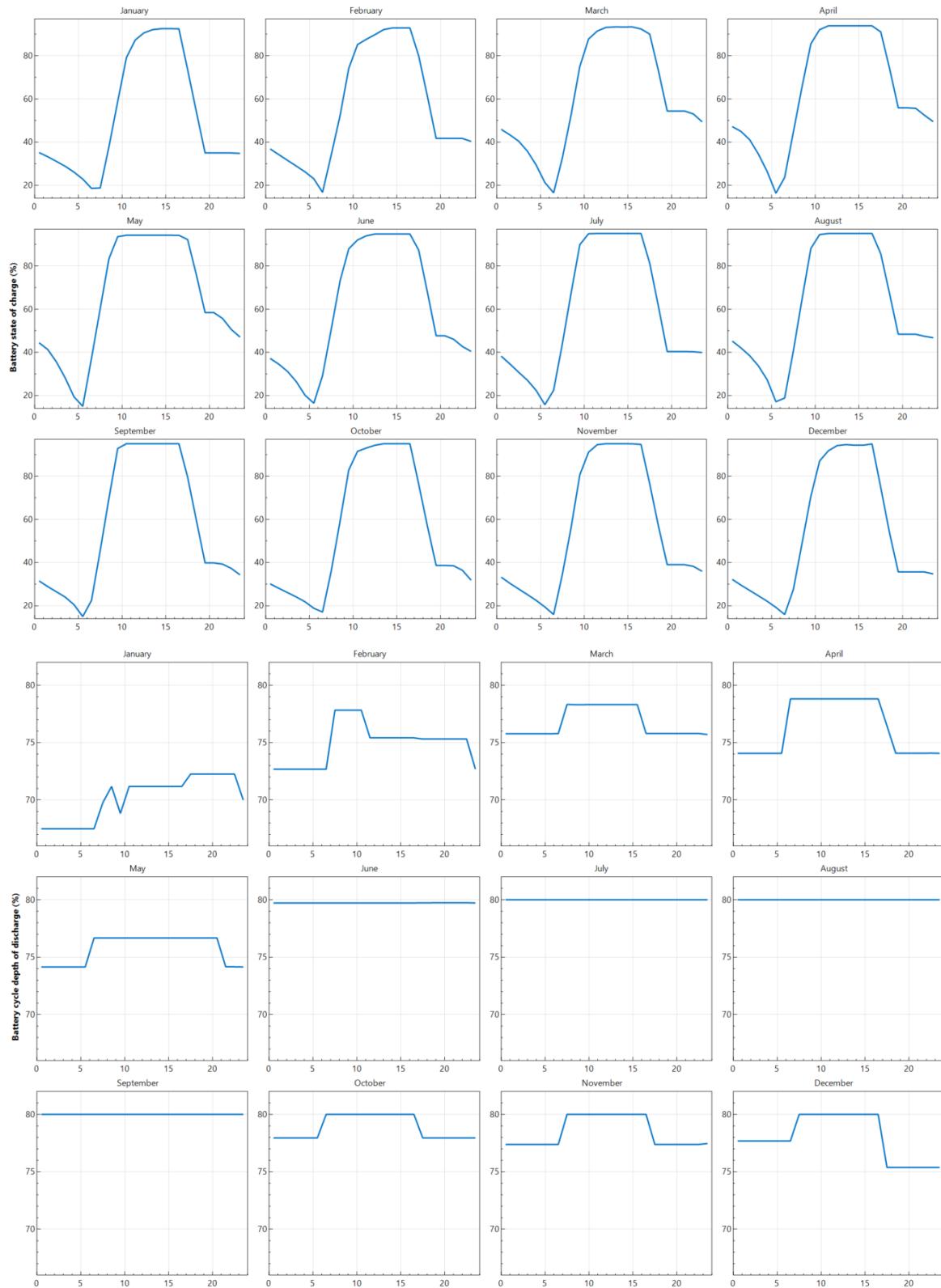
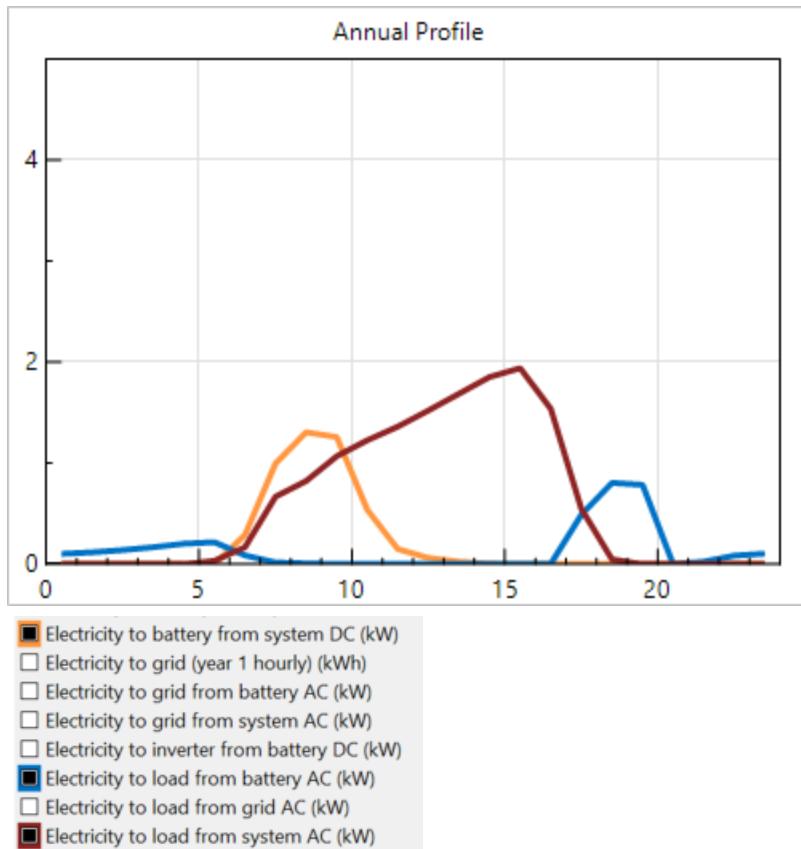


Figure 18.



**Figure 19.**



*Figure 20.*

## Functional Decompositions and Descriptions 0 and 1



Figure 21: Level 0 Functional Decomposition

Table 5. Level 0 Partial Functional Decomposition Description Table

Module	Microgrid
Input(s)	<ul style="list-style-type: none"> <li>• Power from the sun</li> <li>• Backup AC power from the grid</li> <li>• Typical daily hourly power pricing</li> <li>• Solar resource for SLO City farm land</li> <li>• Users have access to breakers to restart the system if needed</li> </ul>
Output(s)	<ul style="list-style-type: none"> <li>• Extra energy produced from the system can go back to utilities</li> <li>• Any module that deals with power will have heat produced as excess</li> <li>• The microgrid can give status updates on the system</li> </ul>
Functionality	Intelligently and profitably generate, store and send energy. Remain stable.

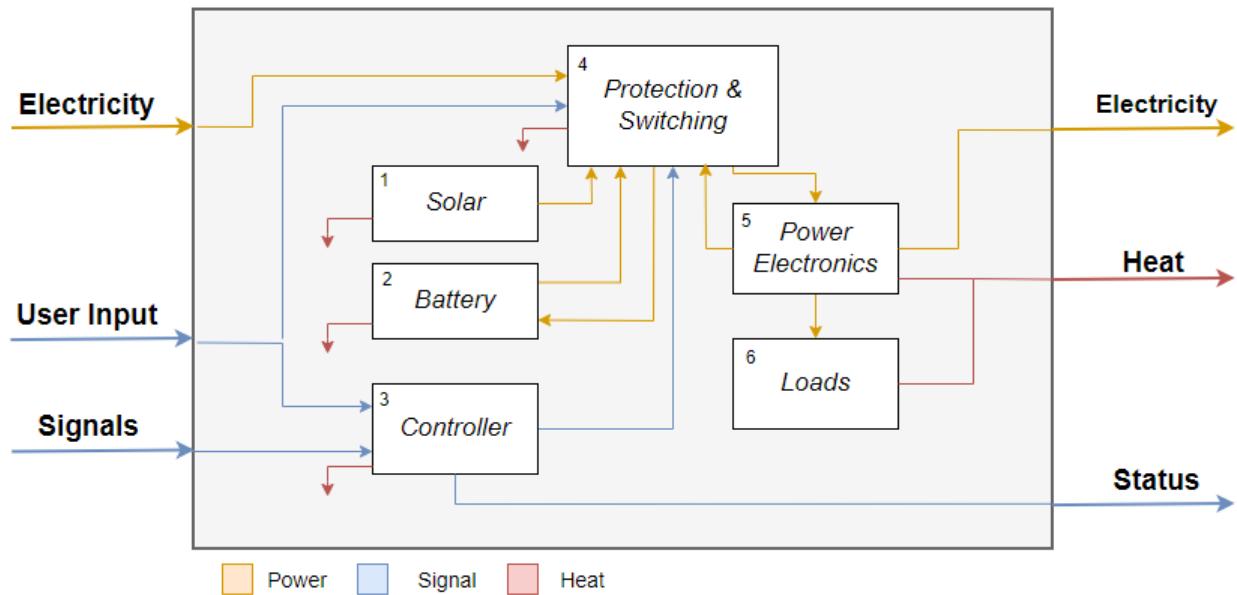


Figure 22: Level 1 Functional Decomposition

Table 6. Solar Module Partial Function Decomposition Description Table

Module	Solar - 1
Output(s)	<ul style="list-style-type: none"> <li>• Heat</li> <li>• DC power</li> </ul>
Functionality	Panels that generate power for the system

Table 7. Battery Module Partial Function Decomposition Description Table

Module	Battery - 2
Input(s)	<ul style="list-style-type: none"> <li>• Protection from fuses and breakers</li> <li>• Switching</li> <li>• DC power</li> </ul>
Output(s)	<ul style="list-style-type: none"> <li>• Heat from receiving power</li> <li>• DC power</li> </ul>
Functionality	Stores excess energy produced and supplies it back to the loads when needed

**Table 8. Controller Module Partial Function Decomposition Description Table**

Module	Controller - 3
Input(s)	<ul style="list-style-type: none"><li>• Users can add loads to the system</li><li>• Users have access to breakers to restart the system if needed</li><li>• Typical daily hourly power pricing</li></ul>
Output(s)	<ul style="list-style-type: none"><li>• Manages power to loads</li><li>• Controller can give status updates on the system</li></ul>
Functionality	It is the brain of the microgrid. It chooses what loads get power when and has the ability to check the status of the battery.

**Table 9. Protection & Switching Module Partial Function Decomposition Description**

Module	Protection & Switching - 4
Input(s)	<ul style="list-style-type: none"><li>• AC power from the grid</li><li>• Additional loads from the user</li><li>• DC power from the microgrid's solar panels</li><li>• DC power from the microgrid's batteries</li><li>• Inverted DC power from the power electronics</li><li>• Switching signals from the controller/current sensing</li></ul>
Output(s)	<ul style="list-style-type: none"><li>• Heat from the relays and the switches</li><li>• Sends generated DC power back to the battery</li><li>• Sends generated DC power to the power electronics to be converted into AC power for the AC loads</li><li>• Disconnect actions</li></ul>
Functionality	It houses all of the relays and switches to provide protection for the system for over currents, and allow intentional disconnection .

**Table 10. Power Electronics Module Partial Function Decomposition Description Table**

Module	Power Electronics - 5
Input(s)	<ul style="list-style-type: none"><li>• DC power from the solar panel and battery</li></ul>
Output(s)	<ul style="list-style-type: none"><li>• AC power to loads</li><li>• Regulated DC power to loads</li><li>• Heat from components</li><li>• AC power to the grid</li></ul>
Functionality	The power electronics will convert DC to AC if necessary and will also regulate the voltages that go to the loads.

**Table 11. Loads Module Partial Function Decomposition Description Table**

Module	Loads - 6
Input(s)	<ul style="list-style-type: none"><li>• AC and DC power</li></ul>
Output(s)	<ul style="list-style-type: none"><li>• Excess heat</li></ul>
Functionality	Loads vary from the water pump, lights, HVAC, and any outlet.

## **PG&E's Rule 21 and NBT Schedule Specifics**

### **Rule 21 Interconnection Review Process, Applies to All Considered System Configurations (Non-Export, Paired Storage, and Multiple Tariff)**

In our section “PG&E’s NBT Schedule’s Relevance to City Farm” we outline why City Farm will make a Rule 21 Interconnection Request and apply for a new Billing Agreement so we will not rehash it here. We will start by describing the defined process for how the submission of the request works (Rule 21 Sections E) and continue to how the corresponding application is reviewed and judged with various mandates applied along the way (Rule 21 F-O). If the Interconnection Application is found valid, then PG&E will proceed with the Interconnection Application Review process. [Rule 21 F.1.a] If that review is passed PG&E will provide City Farm with the relevant Generator Interconnection Agreement (and Customer authorization form). [Rule 21 F.2.e]. One would also go through permitting approval with the local authority having jurisdiction (AHJ) and likewise attach those permits to the relevant Agreement and Customer Authorization form. There is time for negotiation on cost estimate (like cost for upgrades to the PG&E equipment on the interconnected facility) [Rule 21 F.2.e]. We understand that the second form, the Agreement and Authorization form being accepted and signed by all parties, locks the facility into a new Billing Agreement and gives them permission from PG&E to build (which should be completed by the commercial operation date). PG&E will do commission testing where applicable according to Rule 21 L.5 (we expect to avoid this). The facility cannot be connected in parallel with PG&E’s grid until PG&E gives express written permission. We will not actually be submitting anything (besides considering sending in a request for free information) so while we fill out forms as an academic exercise, we expect that whatever professional engineering company who actually submits them will verify they are correct and will thus take any responsibility for their submission. The forms should not be submitted without licensed engineer overview and assumption of any liability. [Rule 21 D.1, Rule 21 Appendix A, PG&E’s NBT Special Condition 3, and associated forms 79-1174-03 (A, C, D, H, ect) , 79-973, 79-1193-03 or 79-1069-03]. All forms locateable at [95].

#### **Step 1: Applicant Initiates Contact with Distribution Provider**

It makes sense given the language of “initiating contact” that the first step to the Interconnection Review process will be to contact PG&E. PG&E Rule 21 E.2.a describes that an applicant can

make a request for information and documents and within (3) business days information should be provided outlining “sample agreements, Interconnection Request, technical information, listing of Certified Equipment, Initial and Supplemental Review fee information, applicable tariff schedules and Metering requirements.” This would have been super helpful information to have. We spent a lot of time and ink attempting to understand and expound on most of these aspects of the project.

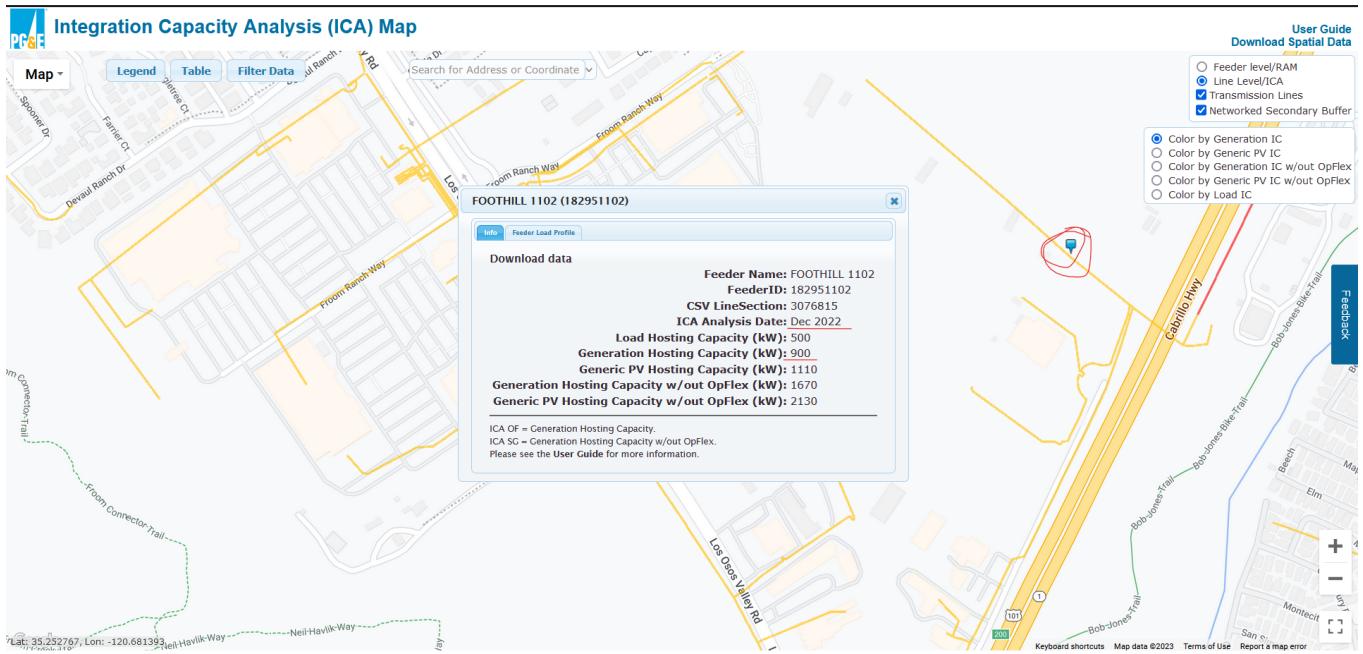
We understand the Rule 21 E.2.a information to be separate from a “pre-application report” as described in Rule 21 E.1 (which costs money, provides information on a big list of detailed technical matters and should be reported within (10) business days from the request for information). But when we asked PG&E about the Rule 21 E.2.a information they were not forthcoming in providing it. We had City Farm fill out a 79-1095 form so that PG&E would recognize us as City Farm’s representative. But the interconnection manager that our requests were escalated to responded that we would request a pre-application report (with its fees running between \$300 and \$1200). This was disappointing and having to parse through PG&E’s documents without aid (or confirmation that we were interpreting things correctly) took a good deal of time and energy. Perhaps we made a few mistakes 1) explaining that we were non-licensed students working on a academic project 2) asking about the distinction between the technical information that was included under Rule 21 E.2.a and what information would only be obtainable via purchased report while referencing the PG&E Application Review Screens 4) being unwilling to be pushy about how we interpreted E.2.a (apart from not wanting City Farm to be reviewed in any capacity, one of us wants to work at PG&E doing interconnection and was uninterested in being obnoxious to a manager). But regardless, we accept responsibility for not obtaining that Rule 21 E.2.a information even though it made our project more difficult.

We did not pay for a Rule 21 E.2.a pre-application report either. The information we found most relevant in any of the reports (Existing service transformer kVA rating, Primary Voltage and secondary Voltage rating, Configuration on both Primary and Secondary Side (i.e. Delta, Wye, Grounded Wye, etc.), Characteristic impedance (%Z), Confirm if the transformer is serving only one customer or multiple customers, Provide the Available Fault Current on both the Primary and Secondary Side) was in a version of a report that costs \$900. This was far above our ability to pay and we had promised City Farm that our interactions with PG&E (for the sake of the report)would not make them liable for any cost. Throughout the report we take our best guesses

at what some of that information is, but we expect that the professional engineering company will simply pay for it (if they haven't paid for it already during the 2019 City Farm Solar project).

## **Step 2: Choose Review Process and Make an Interconnection Request**

Rule 21 Section E.2.b outlines a choice between making a request under a fast-track review process or a detailed study process. We understand that all the facilities that we are considering designing will be able to request the fast track process but only the non-export facility will be guaranteed review under fast track; for the other two facilities (which would fall under the NBT Tariff) we understand it would be PG&E's discretion to allow a fast track review or not. [Rule E.2.b] We strongly suspect that PG&E will review City Farm's facility under fast track regardless of the type of facility though. 1)The site has already been reviewed in 2019 and was approved for interconnection. 2)We are planning on designing the system such that it will not even qualify for a supplemental fast track study. 3)Further, while the new facility would potentially triple the power output to something more like 15 kW, that is still small potatoes given what PG&E's infrastructure can handle, we'll explain. The Rule 21 E.2.b.i on fast track directs the reader to review the Integration Capacity Analysis (ICA) map [69]. This is a map detailing the approximate amount of capacity (load and generation) that PG&E's feeders and line can handle. The line that City Farms connects to can handle 900 kW of new generation capacity (see Figure 23 below). While this ICA study was completed approximately 6 months ago (and the hosting capacity decreases as more generation equipment is attached to the line, which has likely occurred in the last 6 months), this ICA represents the most up to date data available to us. That data shows that PG&E can support ~60 facilities sized the same as ours on this line.



**Figure 23. ICA Map, City Farm's Feeder Capacity**

Now that we have assured ourselves that we believe PG&E will review us under fast track once requested, the next step would be to actually make the interconnection request. This, we understand, will be done by filling out form 79-1174-03, the Rule 21 Generator Interconnection Application as well as its relevant appendixes: (A) for Customer and Project Information, either (B) or (C) for non-export or export respectively, (D) for solar, and (H) for energy storage. The form is titled “Interconnection Application” but its first section (A) reassures that it “is used to request the interconnection to PG&E’s Electric System.” That form will work for all of our possible system types:

- “(1)Non-Exporting Generating Facilities;
- (2) NEM/NEM2/NBT Solar (PV) (other than PV 30 KW or less)
- ...
- (5) NEM-MT/NEM2MT/NBT-MT- generating facilities subject to multiple tariff treatment.”

PG&E has a tool on their website to submit the forms when the time comes to that (for the professional company). All forms locateable at [95].

### Step 3: Assuming Liability for Cost

At that time City Farm makes the application, they also accept liability for fees and costs associated with their interconnection request. Those fees are expounded upon in Rule 21 Table E.1 (depicted in our Figure 24 below). Even though this table explicitly references NEM 2 the CPUC NBT Tariff 8.5.3 mandates “Interconnection fees remain unchanged from D.16-01-044.” D.16-01-044 established the NEM 2.0 interconnection fees that PG&E displays below.

**TABLE E.1**  
**Summary of Interconnection Request Fees, Deposits and Exemptions**

<u>Generating Facility Type</u>	<u>Interconnection Request Fee</u>	<u>Supplemental Review Fee</u>	<u>Detailed Study Deposit</u>	<u>Additional Commissioning Test Verification</u>	<u>Cost Envelope Option Deposit****</u>	<u>Modifications Fee (Table Ee.1) *****</u>
Non-Net Energy Metering and > 1 MW NEM-2*****	\$800	\$2,500*	For a Generating Facility with a Gross Nameplate Rating of 5 MW or less and applying to the Independent Study Process, \$10,000 for a System Impact Study or the DGS Phase I Interconnection Study in the case of the Distribution Group Study Process; and \$15,000 for an Interconnection Facilities Study or DGS Phase II Interconnection Study in the case of the Distribution Group Study Process.  For a Generating Facility with a Gross Nameplate Rating above 5 MW, \$50,000 plus \$1,000 per MW of electrical output of the Generating Facility, or the increase in electrical output of the existing Generation Facility, as applicable, rounded up to the nearest whole MW, up to a maximum of \$250,000.	\$150/Person Hour**	\$2,500	\$0
≤ 1 MW NEM-2***	\$145	\$0	\$0	N/A	\$2,500	\$0
NEM-1	\$0	\$0	\$0	N/A	\$2,500	n/a
Non-NEM Solar ≤ 1MW*****	First \$5,000 of study fees waived			\$150/Person Hour**	\$2,500	\$0

\* Optional \$1,000 additional fault current study fee pursuant to Section F.2.c.ii. Pursuant to D. 20-09-035, Applicants have the option to pre-pay the non-refundable Supplemental Review Fee (such as concurrently with the Interconnection Request fee) or separately upon completion of the Initial Review.

\*\* Plus additional costs for travel, lodging and meals.

\*\*\* Applicants that participate in the Single-Family Affordable Solar Homes (SASH) program are exempt from the Interconnection Request fee.

\*\*\*\* Interconnection Requests that have selected the Cost Envelope Option and that subsequently qualify for and pass the Fast Track Process evaluation, as well as NEM Generating Facilities and Solar ≤ 1 MW Generating Facilities evaluated under the Independent Study Process, must provide the Cost Envelope Option deposit in accordance with Section F.7 to remain eligible for the Cost Envelope Option.

\*\*\*\*\* The fee will be set to \$0 for now, until PG&E submits a new Advice Letter to increase it. Note: the fee does not apply to NEM-1 nor NEMFC by statute. SASH is also exempt from this fee per D. 16-01-044.

\*\*\*\*\*Solar ≤ 1MW that does not sell power to Distribution Provider (per D.01-07-027) nor participate in NEM-1 or NEM-2.

\*\*\*\*\*see Section B.1 *Applicability* regarding NEM-2 projects greater than 1 MW interconnecting on Transmission.

*Figure 24. Rule 21 Table Summarizing Interconnection Request Fees*

So under NBT (our facility will definitely be under 1MW) City Farm will pay a \$145 interconnection fee and put down an optional \$2500 cost envelope deposit (the cost envelope to be discussed more later). For a non-exporting facility (non-NEM solar) we will have the same cost envelope deposit but E.3.0 also waives interconnection request fees entirely and as the above table says the first \$5000 of study fees is waived. We believe the study fee that applies to could be the \$2500 supplemental review fee (plus the optional \$1000 fault current study fee). But again, we will design with the fast-track initial study in mind and hopefully be able to avoid supplemental review (more on this in later section). We also expect to avoid commissioning testing by strenuously examining PG&E certifications on all equipment, but recognize that it is still possible. It is difficult for us to accurately estimate how many person-hours this could amount to, but we imagine that it will be less than or equal to two persons working a full 8 hour day (16 person hours).

The additional costs that City Farm will be responsible for are talked about in E.4. To start NEM 2.0, NBT and multiple tariff (of the type relevant to us) customers are exempt from costs associated with Distribution or Network Upgrades (Rule 21 E.4.0, tables E.2 and E.3). We also do not expect that non-export customers' facilities will cause a need for Distribution or Network Upgrades. What NBT and non-export customers will be liable for are interconnection facility costs [table E.2]. In this context we understand this to mostly be about meeting improvements the new facility requires. E.4.d also includes: "Producer [bears] responsibility for costs associated with changes to the operating characteristics at the Point of Interconnection necessitated by Distribution Provider's upgrades to the Transmission or Distribution System from time to time." We believe this refers to upgrades that PG&E will enact over the long term, for example to provide more capacity on the entire distribution line, which we will not estimate and include in our financial report.

### Step 3.a: Cost Envelope Option

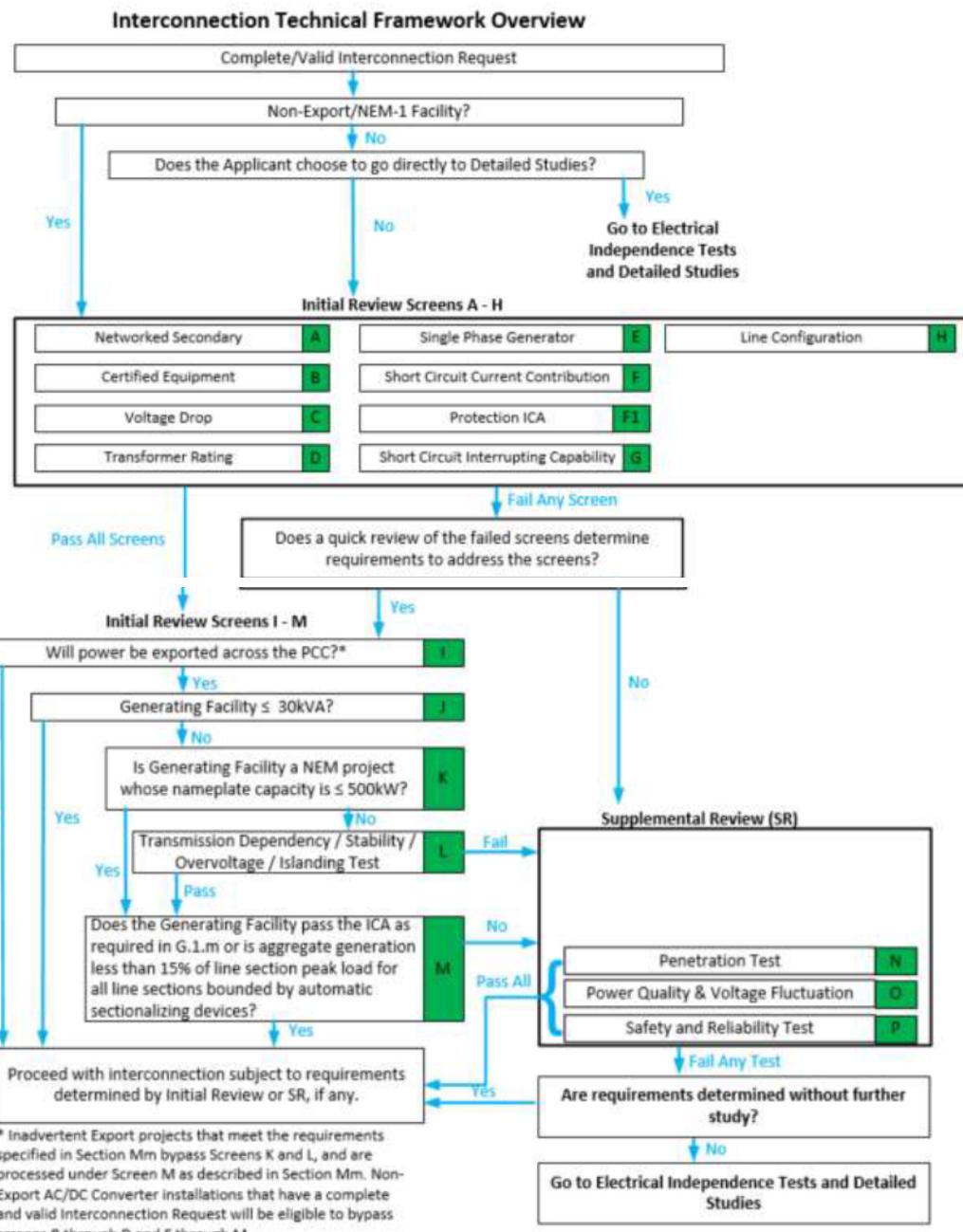
We understand that cost envelope is an option we could choose to apply under if we were worried that we would be liable for costs of interconnection facility upgrades. PG&E would estimate the costs City Farm would be liable for during the application/interconnection process and would then only be able to charge for costs +-25% of that original estimate. Applying under this would have some effect on the timeline of the application. Since we have difficulty doing our own estimation on costs we will be liable for (see lack of confidence on service size and

metering requirements), we will leave it to the professional to decide if applying under cost envelope makes sense for City Farm.

#### **Step 4: Valid Application, Fast Track Review Process and AHJ Permit**

Once PG&E approves that interconnection request they will perform the review. It will hopefully be a fast track review, which is broken into initial review and supplemental review [Rule 21 F.1.b]. Again, we will design in the hope of passing the initial review without issue and will hopefully not be subject to the supplemental review (or its costs). So we will only expound on the initial review here. There are some circumstances (such as applying for some kinds of non-export facility) that will reduce the number of screens further, these reductions will be explained in sections corresponding to relevant circumstances.

The fast track initial review consists of Screens A through M [Rule 21 F.1.b]. We have a couple graphics from PG&E (from Rule 21 G) that help visualize the process before going into detail (see below Figure 25). So far we have described up to “Initial Review Screens A-H” which we expect to get to with both NBT and non-exporting facilities. We now look at screens A-H as defined by Rule 21 G.1.



*Figure 25. Flowchart of Rule 21 Review Process*

Screen A: Is the PCC on a Networked Secondary System?

No → Pass to screen B

The PCC does not appear to be on a networked secondary to our eyes. On the ICA map referenced earlier, we were able to see the ICA values on the line City Farms connects

to. According to the ICA user guide [69] map question 8, this value would not appear if the line was part of a networked secondary system.

Screen B: Is Certified Equipment used?

Yes→ Pass to Screen C

As we will discuss in detail, we will try strenuously to only use equipment that is certified for interconnection uses by PG&E and we expect to be successful. Site commissioning testing may be required even if this screen is passed. But we understand, passing this screen will remove the chance the PG&E will need to validate/verify equipment prior to that.

Screen C: Is the [motor] Starting Voltage Drop within acceptable limits?

Yes→ Pass to Screen D

This screen, we understand, only applies to facilities whose generation equipment is a motor that must be started with inrush current from PG&E's service. As we will be using solar panels, that is not the case for our facility.

Screen D: Is the transformer or secondary conductor rating exceeded?

No→Pass to Screen E

Compare the maximum aggregated Gross Ratings<sup>1</sup> for all the Generating Facilities connected to a secondary distribution transformer with to the transformer or secondary conductor ratings.

We will assume the answer to this is no, albeit with little confidence. We believe that the transformer rating is 25kVA but are not sure that that is the case. Additionally, we have no idea what the rating of the secondary conductors are. We can do some tortured reasoning to convince ourselves that the service transformer and conductors will be large enough:

*Per the NBT, the generation must be sized to meet but not exceed the annual load demand. The transformer must be sized to meet the site's load demand and in our professional experience, should be roughly 20% higher to allow for load expansion. The transformer also has a load that is not on our site (the billboard), and must be rated to supply that as well.*

*Even though equal load and solar generation annual demand/supply is equal, it does not mean that their instantaneous powers are. The solar panels only generate for a portion of the day and the loads can draw over the whole day. So even if the transformer is rated to meet the instantaneous power draw for the load, and the generation is "sized to compensate the load (on an annual basis)" the power exported by the panels could be greater than the power rating of the transformer. Additionally, we understand the NBT generation size to only account for solar generation and not the battery output which this screen will ostensibly also consider as part of the gross rating of the facility.*

1) There is potentially confusion for us in what to count as part of the gross rating of the generating facility and how that is different from a calculation of the "system size." According to Rule 21 definitions a generator is any device converting mechanical, chemical or solar energy into electricity, this would seem to include batteries in addition to solar panels even though we don't understand batteries to be "generating" energy. The gross rating is the total gross generating capacity of a Generator. Aggregating these would seem to imply simply adding the solar CEC-AC rating with the batteries continuous discharge rates. Additionally, we note there is no reference to inverter ratings. This gross rating is different from a nameplate rating. The later subtracts the electrical power consumed by equipment needed to run the generation part of the facility.

Meanwhile the PG&E NBT Schedule special condition 3 declares that, for its purposes solar size is the larger of the solar panels CEC-AC rating, and the aggregate solar inverter capacity, but for REGF's paired with storage (assumedly including , the inverter size of the storage system is not included in the size of the REGF system.

At the end of the day though, we do not definitively know the size of the transformer and thus cannot be confident that we will pass this test. But we will design such that the aggregate gross generation is less than the 25kVA we believe the transformer can handle and assume that the conductor will have the capacity to accommodate that same amount of power.

#### Screen E: Does the Single-Phase Generator cause unacceptable imbalance?

No→Pass to Screen F

This test applies “If the proposed Generating Facility is single-phase and is to be interconnected on a center tap neutral of a 240 volt service, does it cause unacceptable imbalance between the two phases of the 240 volt service?”

We believe that this refers to imbalance in current drawn between the Lines A and C of the 120/240v split phase service. As we are planning on connecting the facility across both lines A and C to pull/push current at 240v (not between the center tap neutral line and either Line A or C for 120v) we don’t understand a situation that the system would cause imbalance during its normal operation. We interpret this screen not to apply to our system.

#### Screens F, G, and H

Do not apply→ Pass to Screen I

All these screens do not apply to facilities having aggregated Gross Rating less than or equal to 30kW, but we already commit to 25kVA as the upper limit of our design so we will disregard them.

#### Screen I: Will power be exported across the PCC?

If yes→ continue to screen J

This will be the case if we have an exporting facility under NBT.

If No→ Meet one of Options 1-8 and the initial review is complete

This will be the case if we have a non-exporting facility. We discuss Options 1-8 in the section dealing specifically with non-export. Note, option 8 further releases one from some of the above screens.

#### Screen J: Is the Gross Rating of the Generating Facility 30 kVA or less?

Yes→ initial review is complete

We already commit to a design with an aggregated Gross Rating less than 25kVA.

PG&E also releases tips on the review process that include:

Make sure interconnection is below the main breaker.

Have only one AC disconnect and ensure it is within 10' of the service panel (meter). [53]

Once City Farms is assured that they will not need to make any changes to their design based on the review, they can submit their design to the AHJ (San Luis Obispo) for permitting. From what we understand, as long as the design meets Title 24, the CEC and the rest of San Luis Obispo's codes it should be permitted.

### **Step 5: Finish Process**

From there PG&E would supply the Agreement and Customer Authorization form, negotiate the costs for PG&E to do work to make the facility feasible, do commissioning testing and provide authorization to parallel. We gloss over this part here because we already discussed it in the Rule 21 introduction section and we do not see it as all that relevant to the design considerations.

## **Intro to System Configuration and Subsequent Requirements**

We must decide what PG&E schedule we will connect under, this has a huge influence on the components and settings that will make up the system. It will partially answer questions such as: How much generation capacity? How big of inverters will be used? How complicated of a control scheme will we need? Once a PG&E schedule is chosen that fits with City Farm's power demands and storage needs, we can choose appropriate components and design the system.

Let's also start with some PG&E schedules we will not be falling under. We will not design systems on the basis of any of the following:

- 1) Virtual Metering: We will not be taking service under Virtual Metering, which would be the case if there were multiple metered customers on one property that all shared credits for a single generation facility. This is not the situation on City Farm. While we intend to create a system design that extends power to a tenant at the back of City Farm's parcel, this tenant does not have a separate meter or represent a substantial load (a receptacle or two to occasionally run small hand tools). Currently, all charge for tenant power at City Farm is included in the tenants' rent and is not individually measured. We operate under the assumption that any new power to another tenant will follow the same principle.
- 2) Aggregation: As discussed above in section PG&E's NBT Schedule's Relevance to City Farm, net metering aggregation is for a single customer with multiple meters across multiple adjacent parcels. This is not the situation on City Farm's property.
- 3) Any schedule reserved for a Small Customer (as defined in PG&E Rule 1). We are on an agricultural rate and thus do not qualify as such.
- 4) Any schedule not allowing for a battery/energy storage component. Having batteries that are at least partially charged is essential to store excess solar energy for later use and provide backup power in the event of a PG&E loss of service.

This leaves us with three remaining system configurations, non-export, paired storage and multiple tariff facilities.

## **System Configuration: Non-Export**

The first sort of system we consider designing. The Rule 21 definition of Non-Export: "When the Generating Facility is sized and designed such that the generator output is used for Host Load only and is designed to prevent the transfer of electrical energy from the Generating Facility to the Distribution Provider's Distribution or Transmission System." In less technical language, the generating facility only powers on-site loads, not exporting power to PG&E's grid.

### **Define Non-Export System With Rule 21 Screen I**

Now that we have some idea what "non-export" means specifically, we should say that we have come to understand that none of this will be directly binding. For that binding language, we have to read through PG&E's Rule 21.

We start the analysis with what we understand to be the Rule 21 section that determines whether or not your system is defined as non-exporting, Rule 21 Section G.1.i. This section describes Screen I and asks "Will power be exported across the PCC?"

PCC means "point of common coupling", the place where electrical conductors of PG&E transfer electricity to electrical conductors of the customer (or visa versa in the case of an exporting system). For a non-export facility we will not export across the PCC and thus must meet (1) of (6) possible options which we describe below. These "Options" track well with the "requirements" on PG&E's website but we will look at the options in detail. Note that many of the PG&E option numbers are skipped in the below analysis.

Option 1 "Reverse Power Protection"-- A Protective Function (via a relay or integrated inverter/controller) with settings to trip or otherwise take action if power is exported at more than (.1%) of the service's transformer rating (in our case 25 VA) and with a maximum (2) second time delay.

Option 2 "Minimum Power Protection"-- An underpowered protection relay will ensure that the customer generating facility is always importing at least (5%) of its total gross rating, again with a (2) second time delay on any action. Then no electricity can be exported.

Option 3 “Certified Non-Islanding Protection”--all of the following conditions be met:

- a) The total Gross Capacity of the Generating Facility must be no more than 25% of the nominal ampere rating of Producer’s service equipment;
- b) The total Gross Capacity of the Generating Facility must be no more than 50% of Producer’s service transformer capacity rating (this capacity requirement does not apply to Customers taking primary service without an intervening transformer); and
- c) The Generating Facility must be Certified as Non-Islanding<sup>2</sup>.

It would be difficult for us to design for Option 3 with confidence as we did not purchase a pre-application report and thus can only estimate the size of the service equipment/transformer.

Option 4 “Relative Generating Facility Rating”-- The capacity of the generation facility would be sized to be no larger than 50% of the customers verifiable minimum load over the last 12 months.

We do not really like this option because we plan on sizing the system to meet loads to be installed soon. This is allowed under NBT but we do not see it as a possibility under this Option 4 provision.

Option 7 “AC/DC Converter”-- Would use a non-exporting AC/DC converter, which would solely import AC power for use of the customer’s DC loads. With (DC) generation not able to be transferred back to AC power to export from the grid.

2) We understand the definition of [Non-]Islanding to be somewhat contradictory depending on the document it is being used in.

The 2023 NEC definition of “Island Mode” is “the operating mode for power protection equipment or microgrids that allows energy to be supplied to loads that are disconnected from electrical power production and distribution network or other primary power source.” Which we interpret to mean NEC’s “Island Mode” is when your customer protection equipment allows your customer loads to be powered by your customer generation equipment when PG&E’s distribution network (and power production) is disconnected i.e. your customer system is physically disconnected from PG&E’s grid. As would be the case if you safely used back up batteries during aPG&Eoutage.

The 2023PG&ERule 21 definition of “Islanding” is “A condition on Distribution Provider’s Distribution System in which one or more Generating Facilities deliver power to Customers using a portion of Distribution Provider’s Distribution System that is electrically isolated from the remainder of Distribution Provider’s Distribution System.”

Which we interpret to mean that “Islanding” is when your customer protection equipment allows your customer generation equipment to remain connected and shoot power to a different customer’s loads over PG&E’s distribution grid in the event of aPG&Eoutage i.e. your customer system remains connected to PG&E’s grid. This would be unsafe for the reason that PG&E workers could expect that portion of the distribution grid to be de-energized during an outage and be exposed to unexpected high voltage when doing work.

Since “non-islanding” here is in the context of a PG&E document we understand it to mean-- equipment that will detect when PG&E’s grid is de-energized and disconnect our customer system from the PG&E grid to keep the grid safe for other PG&E customers and PG&E workers.

We believe Option 7 would make sense to use if we were going to design a DC micro-grid system with fewer/cheaper inverters and supply lots of DC loads.

Option 8 “Certified Power Control System (PCS)”-- This calls for a non-export (import-only mode) certified PCS. The PCS has an open loop response time (OLRT) and export reduction time of no more than (2) seconds as described in Rule 21 Section Mm1. We simply copy the relevant Section Mm1 below in Figure 26.

Mm1. OPTION 8: Non-Export Utilizing Certified Power Control Systems

The following are the minimum requirements for Non-Export systems that use certified power control systems (PCS) with an open loop response time (OLRT) no more than two seconds. It should be noted that other factors relevant to the Interconnection Study process may necessitate additional technical requirements that are not explicitly noted here.

1. Use a PCS that passes the requirements of the 2019 Underwriters Laboratories (UL) Power Control Systems Certification Requirements Decision (CRD) test protocol. Non-Export systems may use a PCS that passes later published revisions to the CRD test protocol or may use a PCS that is certified to the UL 1741 certification standard, if UL incorporates the test protocol for PCS into UL 1741 in the future. The NRTL evaluation must have determined that the PCS conforms to the non-exporting functionality in accordance with the relevant CRD or UL published standard.
2. Use a PCS that is certified with an OLRT of two seconds or less, as provided in the PCS's specification data sheets.
3. The PCS must reduce export to zero or less within two seconds of commencing export. A PCS that is certified with an open-loop response time of two seconds or less, and a time to reach steady state of 10 seconds or less, meets this requirement.
4. Set the PCS to not export (zero-export).
5. Use only UL 1741 listed grid-support non-islanding inverters as approved by this tariff.
6. Maintain voltage fluctuations at the limits specified in Electric Rule 2.

(L)  
(L)

**Figure 26. Rule 21 Section Mm1**

As visible in the California Energy Commissions Solar Equipment List, the UL 1741 CDR certification is relatively common to PCSs and so is the sub 2 second OLRT in import only mode; we do not believe it would be much trouble to design with one. If we design with this kind of PCS device, we will have to do a little more digging to verify that the device reaches steady state in (10) seconds or less but this does not seem like a difficult requirement to meet. We will deal with device settings in our forms section, but will choose a device that can be set as per Mm1 (4). We would definitely make sure that the device is non-islanding (per PG&E's definition) as this is a big safety concern. In Rule 2 we did not find specific voltage fluctuation limits that customers must maintain, but we make an assumption that Mm1.6 here refers to the voltage

fluctuations that this refers to the same voltage levels that PG&E attempts to maintain at the point of service as shown in figure 27 below, which depicts a PG&E Rule 2 table.

Nominal Two-Wire And Multi-Wire Service Voltage	Minimum Voltage To All Services	Maximum Service Voltage On Residential And Commercial Distribution Circuits		Maximum Service Voltage On Agricultural And Industrial Distribution Circuits
		Class A	Class B	
120	114	120	126	126
208	197	208	218	218
240	228	240	252	252
277	263	277	291	291
480	456	480	504	504

*Figure 27. PG&E Rule 21 Min/Max Service Voltages*

### Non-Export and Option 8's Effect on Rule 21 Review

Now that we understand some of the hardware requirements to meet a definition of non-export, we can look at the remaining Rule 21 review process specific to non-export. There is a cutout for expedited review of non-export facilities that meet requirements set out in Section N. Most Section N requirements we plan on meeting, things like apply under fast track, pass fast track review, do not require interconnection/distribution upgrades, use the right form, ect. But there are a couple things that likely preclude our ability to use the Section N expedited process; we would have to use Options 3 or 4 (with associated generation size mandates), and there is this clause: “The Generating Facility must be comprised solely of the following specific categories of generation technology: Non-Exporting battery storage.” We are confused by this because it seems to imply that your “generating facility” will be made entirely of battery storage, storage which we don’t understand to be capable of generating any energy. But we plan to use solar to generate power and that (along with uncomfortability with Options 3 and 4) is enough to ward us off of designing with this Rule 21 Section N expedited process in mind.

That being said, choosing a non-exporting system and choosing Option 8 does seem to imply some review facilitation. Under Rule 21 Section E.2.b.i PG&E “shall” evaluate all non-export facility applications under a fast track review. This is important, any facility we consider can request to be reviewed under fast track, regardless of which type of facility we go with (between non-export, paired storage, and multiple tariff) we would request a Rule 21 review under fast track. But with an exporting facility (like paired storage or multiple tariff), PG&E could decide to

review under the more onerous detailed study. Additionally, if choosing Option 8 (the non-export option using a certified non-exporting power control system with OLRT<2 seconds), Rule 21 Section Mm1 (sheet 264) specifies that Screen D (TX or secondary conductor rating) of the review can be omitted, bypassing this screen is nice for us because PG&E would have charged us for the information necessary to verify that screen. Rule 21 Section Mm1 also has provisions for Screens F and G, but as we are planning on our generation facility to have gross nameplate rating below 30kVA , we will not need to consider these screens [Rule 21 Section G.1.f and G.1.g and 53] anyway.

### Non-Export and Billing

If we design a non-export system we will be forgoing the option to push power back onto PG&E's grid for credit. This represents lost income.

Additionally, there is another sub-schedule called Schedule SB for "standby service" that Rule 21 describes, in its Appendix A, as applying to all generators connected in parallel that are not eligible for NBT tariffs. We understand this schedule to impose additional requirements and additional costs [PGE Form 79-285]. All forms locateable at [95].

### "Option" Analysis

After review of these (6) Options, we are most confident in choosing either Option 1 or Option 8. Between Option 1 and Option 2, we find it likely that Option 1 will be easier to design at similar cost and it will not take as much relay programing to set up a special use case if PG&E's grid is de-energized and we want our system to act as a backup. So we like Option 1. We like that the Solar Equipment Lists the California Energy Commission publishes includes references to the things Option 8 calls for. We feel comfortable choosing a device off these lists that will satisfy Option 8 and believe that programming such a PCS will be similarly complicated to programming a relay as in Option 1. We also like that Option 8 comes with review facilitation.

As far as Option 7, we expect AC motor loads to represent a big part of our system and thus find it likely that we are going to invest in [a] good inverter[s] anyway to put on the generation/battery lines. It would make less sense to then to also invest in a separate device that will only service DC loads, of which we have few. If, later, the professional engineering

company has concrete estimates for the new building load (seeing it is smaller than we anticipate) and knows the precise size of the service transformer/secondary conductor, then perhaps Option 3 or 4 would become more workable than it is for us at this time.

### **Summary of Possible Equipment For Non-Export**

Option 1 equipment: A certified/approved reverse power flow relay (more on the certification/approval of the relay in later section) or other device that either trips the generating facility or a breaker that isolates the facility upon power export.

Option 8 equipment: A certified PCS (one that has UL 1741 CRD certification and meets the 2 second OLRT requirement on export, most likely a smart inverter).

## **System Configuration: Paired Storage**

A paired storage system will fall under PG&E's NBT Schedule as it will be exporting energy. According to PG&E's NBT Schedule Special Condition 7 a paired storage facility is one that consists of a renewable energy generating facility (REGF) with energy storage equipment. In our case specifically connecting under NBT-PS with photovoltaic generation charging traditional battery storage for the use of load compensating (in addition to providing back up power to local loads).

### **Definition of Paired Storage In Relation to Non-Export and Multiple Tariff**

The difference from a non-export facility with generation and storage, would be that the NBT paired storage (PS) facility buy/sells energy from/to the grid under a NBT agreement in addition to generating and storing it. The big difference between NBT-PS and NBT-Multiple Tariff (NBT\_MT) is the flexibility in control requirements for NBT-PS and billing structure. An additional big point is that under PG&E's NBT Schedule Rates Section E, NBT-PS will be exempt from the "requirements of Schedule SB--Standby Service". We understand Schedule SB to require additional design requirements, communication with PG&E/CCCE and additional standby charges, so avoiding SB will be a boon to both City Farm and us as designers.

To qualify as a facility under this NBT-PS schedule we must meet the broad requirements of PG&E's NBT Schedule document, and the specific requirements in Special Condition 4 of said document.

### **Potential Complications to PCC Metering**

One of the first mandates applicable to this NBT-PS schedule (and not to non-export systems because they are not on a NBT schedule), is a metering requirement as per PG&E's NBT Schedule Special Condition 1:

"All other net billing [other than multiple-tariff schedule billing] shall be accomplished using a single meter capable of:

- a. separately registering the flow of electricity in two directions (imports and exports);
- b. metering intervals required for billing under NBT (Non-Residential is 15 Min and Residential is 1hr4.); and
- c. meeting PG&E's requirements for transferring usage interval data to PG&E for billing."

The meter currently on the premises certainly already can meter in 15 minute intervals and is capable of transferring that interval usage to PG&E. However, it is potentially unclear if the meter is capable of registering flow in both directions separately. It is a smart meter capable of bi-directional energy measurements and supporting up to 20 channels of data (with optional functionality called soft-switches). [54] It seems likely to us that to separately measure and cumulate all 4 wires for both import and export would take 8 channels. It is possible that the meter already is capable of utilizing all 20 channels (it definitely does time of use measurements and its soft-switch indicator for time of use is left blank on the markings section of the physical meter). Additionally, the CPUC NBT decision in Section 8.4.8 specifically retained 15-minute interval timing with its no-netting (i.e. separately register flow of electricity in both directions) mandate for the reason that “considerable ratepayer investment” has already been made to implement the current advanced metering infrastructure. Taken together we find it reasonable to assume that, if not already compliant, at most a minor change would be made to the meter currently on City Farm’s property to enable compliance with PG&E’s NBT Schedule Special Condition 1. This Special Condition 1 is a separate consideration than the metering requirements that apply to some forms of paired storage facilities which could be required to have multiple meters. We will discuss when this is applicable later, but in that application could then be liable for the significant additional cost of adding another meter to the system (in addition to keeping/slightly upgrading the existing one referred to in Special Condition 1).

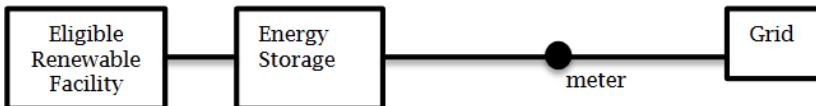
### **Defining Paired Storage with PG&E’s NBT Schedule Special Condition 7**

PG&E’s NBT Schedule Special Condition 7.c describes a few categories that will determine interconnection and billing requirements.

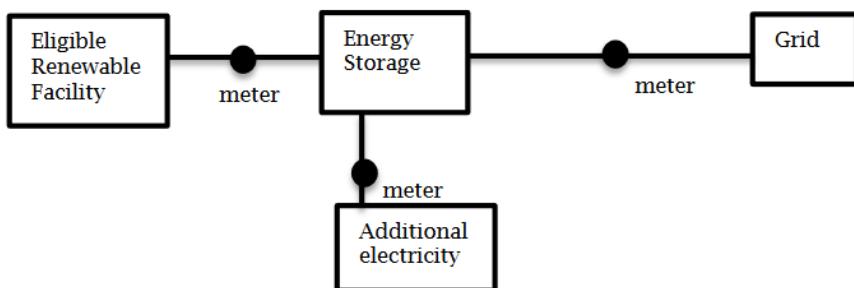
#### **Integration or Direct Connection**

First is whether your storage (battery) group will be integrated or directly connected. Special condition 7.c.1 and 7.c.2 of the same document uses the CPUC’s 2017 Renewable Portfolio Standard (RPS) Guidebook as its basis for this distinction, so we will include a helpful excerpt of the 2017 RPS Guidebook here in Figure 28.

- a) Integrated into the facility, such that the energy storage device is capable of storing only energy produced by the facility, either as an intermediary form of energy during the generation cycle or after electricity has been generated.



- b) Directly connected to the facility, such that electricity is delivered from the renewable generator to the energy storage device behind the meter used for RPS purposes and any electricity from a source other than the renewable generator is included as an energy input to the facility. The energy storage device must be operated as part of the facility represented in the application and not in conjunction with any other facility, renewable or otherwise.



*Figure 28. Integrated or Directly Connected Storage as per RPS Guidebook*

This excerpt from the 2017 RPS Guidebook depicts meters that we do not interpret PG&E to necessarily mandate, but the excerpt helps us understand the requirements laid out in the PG&E NBT Schedule document in Special Condition 7.c. Between the two documents, the definition for integrated storage is pretty consistent, emphasis is put onto the point that integrated storage is only capable of storing energy produced by the REGF; it physically cannot store energy from any other non-REGF/non-NBT facility source. But for the the requirements of directly connected storage, we will include the precise PG&E NBT Schedule Special Condition 7.c.2 language:

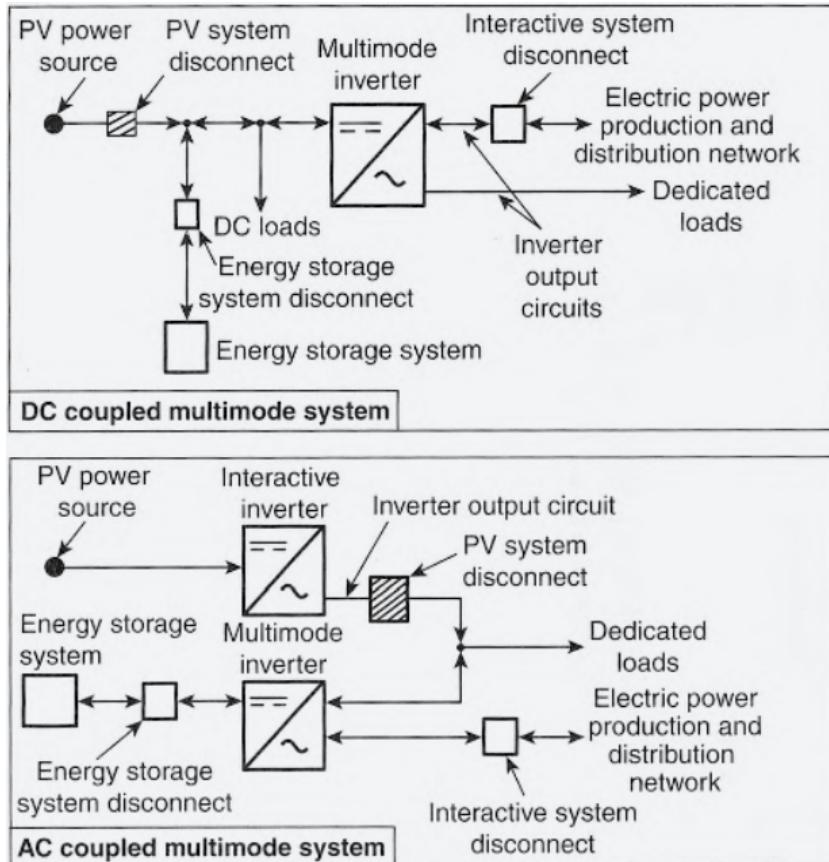
- "(i) The storage device is directly connected to the REGF via an internal power line (i.e., power may not be transmitted from the renewable facility to the energy storage via an external distribution line); and
- (ii) The storage device must be operated as part of the NBT eligible facility."

Keeping both documents' definitions in mind and without definitions included for "internal power line" or "external distribution line", we read (i) and (ii) to say that the storage must be connected to the REGF via a power line internal to the NBT facility, not to say that the power line must be internal to some consolidated product's housing. This connection cannot be via PG&E's distribution system's lines, but could be connected by an underground line behind PG&E's meter. The storage can only be connected to (and operated in conjunction with) an onsite REGF both coming to a single PCC with PG&E.

As we expect that we will, at times, desire to charge the paired battery storage from PG&E's grid (say if the photovoltaic REGF has been blocked by cloud cover for a few days and the batteries are running low), so we will design a directly connected PS system.

### **AC or DC Coupling and Paired Battery size**

The next category to differentiate between in PG&E's NBT Schedule Special Condition 7.c.2 is if the directly connected PS facility will have AC or DC coupling between the REGF and the paired storage. That is, whether the batteries and the photovoltaics will come to one hybrid inverter (DC connected), or each have their own inverters connected together by a line (AC connected). See the below Figure 29, depicting an image from the 2022 CEC Section 690.1.



*Figure 29. AC vs. DC Coupled Systems as per the CEC*

This is a very important consideration, apart from the strictures of PG&E's NBT Schedule (which we are about to dive into), the choice made about AC or DC coupling will also heavily influence the cost of inverter[s], conduit, and other components, and heavily influence how the overall control/protection scheme is implemented.

But while describing alternate requirements for AC and DC connected systems, PG&E's NBT Schedule Special Condition 7.c.2 also takes into account the size of the paired storage facility, sorting sizes into "large" ( $>10\text{kW}$  of storage) and "small" ( $\leq 10\text{kW}$  of storage). We must describe now how the sizes are calculated. According to PG&E's NBT Schedule Special Condition 7.a (in the definitions for AC and DC coupled paired storage):

"The size of the storage system for AC-coupled REGF plus storage systems is the inverter's (or inverters') nameplate capacity (or nameplate capacities summed)" and

"The size of the [DC coupled] storage system is the lesser of the shared inverter's (or inverters') nameplate capacity (or capacities summed) and the storage device's (devices') maximum

continuous discharge capacity (or capacities summed) listed on the storage device's (devices') technical specifications sheets."

There could potentially be confusion in the way the AC coupled definition is worded, it could take into account multiple inverters in a summation. This summation distinctly does not include the inverter that converts the photovoltaic cells' output, it only includes the inverters working on the batteries (if there are multiple). We know this because in a summation table presented at the end of PG&E's NBT Schedule Special Condition 7.c.2 (which will be included later), there is the possibility of having small storage (<10kW inverter nameplate capacity) paired with >30kW of photovoltaic generation (calculated via the larger of the CEC-AC rating of all the panels or the aggregate inverter capacity of the photovoltaic generators, specifically not including the size of the storage inverters [PG&E's NBT Schedule Special Condition 3]). This would be impossible if the generation inverter capacities were included in the storage capacity calculation.

### **"Options" and Their Requirements**

Understanding now the difference between AC and DC coupled systems and large vs. small storage systems, we can categorize the possible requirements that the PG&E's NBT Schedule Special Condition 7.c.2 will mandate. To elucidate what these requirements mean we again look at PG&E's NBT Schedule Special Condition 7.a (the definitions section).

- We could be mandated to ensure "no grid charging." This is what it sounds like, the storage device will not be able to import energy from the grid in order to charge itself. This can be accomplished with a paired storage certified PCS, or with a "PG&E approved physical non-import relay." (more on the certification/approval of the relay in a later section).
- We could be mandated to ensure "no storage export." Again, this is what it sounds like, use a PS certified PCS or an approved non-export relay (again, the approval/certification of such a relay will be described in a later section) to make sure that the batteries are never allowed to export energy to the grid while leaving the photovoltaics able to export.

A note on certified PCS in this paired storage context. PG&E's NBT Schedule Special Condition 7.a describes certification under UL 1741 CRD (issued in 2019), but allowing a more relaxed response time for allowable charging/export of (10) seconds compared to the (2) second OLRT requirement needed for a non-exporting relays in Rule 21.

- We could be mandated to install additional meters (separate from the complication to the basic PCC meter already discussed a few sections above). These additional meters are referenced a few times, directing attention to description of requirements in “Large NBT Paired Storage.” There is no section we see titled as such directly, but we will describe the metering we understand this to refer to, metering options for Large AC Coupled PS in Special condition 7.c.2.iii. These requirements could be:
  - a) install an interval meter for the NBT-eligible generation, meter the load, and meter total energy flows at the point of common coupling; or
  - b) install an interval meter directly to the NBT-eligible generator(s).
  - We do not immediately see why we would choose option a) here, it seems like we could choose option b), install less hardware and still meet the requirement. Nor do we find reference to requiring NGOM in PG&E’s NBT Schedule Special Condition 7 apart from in the summary depicted in Figure 30 at the end of this section. This is confusing, but this will be discussed in as much detail as we can muster in the later section “PG&E NBT Schedule Aspects Applying to both PS and MT”
- We could be allowed/mandated to take billing on a special estimation basis as per PG&E’s NBT Schedule Special Condition 7.c.3.ii. For photovoltaic systems PG&E will use California Solar Initiative Expected Performance-Based Buydown (CSI EPBB) calculator and the capacity of customer panels to come up with an upper limit on how much export energy they will credit in a given month, credit for any export over that amount will be forfeited. We take note that PG&E assumes forfeited energy was the energy credited at the highest rate. Say, if we export 75kWh at 11 cents/kWh and 15kWh at 13 cents/kWh but the upper limit is 70 kWh of export, then all 15kWh at 13 cents is forfeited along with 5kWh at 11 cents regardless of when any of the export takes place.

All that being said, let us now review all the requirements for systems of various size and coupling category as they are described in PG&E’s NBT Schedule Special Condition 7.c.2.

Small ( $\leq 10\text{kW}$ ) DC-Coupled PS:

These systems will not have any “No Grid Charging” or “No Storage Export” requirements. Billing will be on the basis of measured outflow capped by the special estimation referenced in PG&E’s NBT Schedule Special Condition 7.c.3.ii calculated as per the California Solar Initiative Expected Performance-Based Buydown. We can take normal NBT billing under PG&E’s NBT

Schedule Special Condition 7.c.3.i if we either install a (Paired Storage) certified PCS or take on metering requirements applicable to “Large NBT Paired Storage.”

Small ( $\leq 10\text{kW}$ ) AC-Coupled PS:

We understand the requirements are basically the same as the DC-coupled case. We could either take the estimation billing from PG&E’s NBT Schedule Special Condition 7.c.3.ii, or we take normal NBT billing under the same additional requirements:

- a) install paired storage certified PCS; or
- b) install metering in alignment with requirements applicable to “Large NBT Paired Storage”

Large ( $>10\text{kW}$ ) DC-Coupled PS:

Must satisfy “no storage export” requirements:

- a) Use a paired storage certified PCS or
- b) Use a approved non-export relay

If a PCS is used we would be billed under PG&E’s NBT Schedule Special Condition 7.c.3.i, what we have been describing as normal NBT billing. If no PCS is used then we would be billed as if the system was a Multiple Tariff Facility under PG&E’s NBT Schedule Special Condition 4 (with the storage part of the system categorized as non-NBT eligible). We will discuss that billing in the following section on Multiple Tariff facilities. There will be no limit on the size (in kW) of the storage system regardless of how we meet the “no storage export” requirements.

Large ( $>10\text{kW}$ ) AC-Coupled PS:

The paired storage can be sized no larger than 150% of the REGF’s maximum capacity. To be approved the large AC-Coupled PS must also meet one of the following:

- a) install a non-export relay on the storage device(s);
- b) install an interval meter for the NBT-eligible generation, meter the load, and meter total energy flows at the point of common coupling;
- c) install an interval meter directly to the NBT-eligible generator(s); or
- d) operate using a Certified PCS

If we choose to use a paired storage certified PCS we can take normal billing. If not then it will be billed as a Multiple Tariff facility.

This information is helpfully summed up in the following table from PG&E's NBT Schedule Special Condition 7.c shown in Figure 30 below. Although it does seem to brush over stated differences between AC-coupled and DC-coupled systems.

(This table covers storage that is NOT required to be 100% REGF charged) For Both DC and AC-Coupled NBT Paired Storage						
Storage Size	Applicable Interconnection Agreements and Costs				Applicable Billing	Notes
	PV/Wind < 30 kW	Non-PV/Wind REGF ≤1MW ≥30kW PV/Wind ≤1MW	REGF >1Mw	costs (Section 9.c.)	Billed as	NBT Integrity Requirements
DC-Coupled or AC-Coupled NBT Paired Storage with a PCS	Small ( $\leq 10\text{ kW}$ ) 79-1093-03 Large ( $> 10\text{ kW}$ ) 79-1069-03	79-1069-03	79-1078-03	Per 5.i	§3i	Certified PCS, as defined above, required
DC-Coupled or AC-Coupled Small NBT Paired Storage with no PCS ( $\leq 10\text{ kW}$ )	79-1093-03	79-1069-03	79-1078-03	Per 5.i	§3ii	Billed using Estimation Methodology
DC-Coupled or AC-Coupled Large NBT Paired Storage with no PCS sized $> 10\text{ kW}$ And $\leq 150\%$	79-1069-03	79-1069-03	79-1078-03	Per 5.ii or iii	§3iii	NGOM, No Storage Export, or additional metering required, as described above
DC-Coupled or AC-Coupled Large NBT Paired Storage with no PCS sized $> 10\text{ kW}$ And $> 150\%$	Set up and bill as NBTMT (not under NBT-Paired Storage section)					

Figure 30. PG&E's Paired Storage Summary Table

### Paired Storage and Billing

The attractiveness of billing under the PG&E's NBT Schedule Special Condition 7.c.iii, billing as if a NBT facility, depends on if we believe that being "billed consistent with Special Condition 4" (the requirement of PG&E's NBT Schedule Special Condition 7.c.iii billing) is the same as being

“interconnected under the terms of Special Condition 4” (PG&E’s NBT Schedule Rates Section E: trigger for being liable for Schedule SB). In other words, it is not clear to us if NBT-PS has the same liability to Schedule SB as NBT-MT if our NBT-PS facility takes on NBT-MT billing. This is a hard question for us, but we lean towards believing “billed consistent with Special Condition 4” and “interconnected under the terms of Special Condition 4” are significantly different and and NBT-PS facility we design such that it takes NBT-MT billing will not be liable for Schedule SB.

We have already described the PG&E’s NBT Schedule Special Condition 7.c.ii billing (estimation billing) but would like to make a note. Although it seems possible that the estimation PG&E makes could be calculated in such a way to regularly overestimate the renewable energy that our system puts out, we find this unlikely. We will operate under the assumption that the system will more regularly forfeit energy than it will export significant energy from its batteries while also staying below the estimation ceiling -- thus this billing represents (marginal) lost revenue.

We therefore slightly favor the normal NBT billing of PG&E’s NBT Schedule Special Condition 7.c.i. We find it likely that the estimation billing will undercompensate City Farm and we have lingering doubt that NBT-MT style billing could expose them/us to liability for Schedule SB requirements and costs.

### Paired Storage Options’ Analysis

We find it likely that a DC connected system with a single inverter will be cheaper and easier to design. This is attractive. Less components implies less components that can fail and cripple the facility. We also believe that if we were to AC connect the system both inverters would have to meet certification requirements (be smart inverters). There wouldn’t be an option to buy one cheap one (a cheap battery inverter for example) and have the solar inverter do the heavy lifting (in terms of response to stimuli and control of power flow). There could be potential issues if the way we want to size solar and battery sizes are too different or too comparable and we cannot find a single inverter to accommodate both sizes economically.

With our billing assumptions in mind, we do not much see the point of having a large storage with anything a PCS. Even if we install a non-export relay under “no storage export” (which could be a cheaper control method) we would still be billed like a multiple tariff facility and potentially liable for Schedule SB. We discuss metering later but, suffice it to say that we find it difficult to judge the installation (and potentially ongoing costs) of having PG&E install and

service additional meters. Nor do we see third party meters as a very viable option. So we are uncomfortable with the metering option of large storage as well.

Having a small paired storage without a PCS could be economical if the savings vs. an inverter without PCS capability is significant. Although the system with a non-PCS inverter would still have to be capable of judging battery storage to control charging/discharging and the inverter would have to be "smart" as per Rule 21 Hh. With this in mind the savings on the non-PCS inverter seem likely to be minimal, especially considering income losses to estimated billing associated with non-PCS small systems.

There is nothing in our analysis that would suggest that we would need a battery storage output rate to be more than 150% the output rate of our photovoltaic generation. So we are confident that we will not be inadvertently tipping into a NBT-MT facility unless we want to be scheduled as such.

## **System Configuration: Multiple-Tariff**

As per the overview section of PG&E's NBT Schedule, a multiple tariff facility is one that has multiple generators behind the same meter where some of the generators (photovoltaics) are NBT eligible, they are on the list of REGF eligible tech in the PG&E NBT Schedule that we reference, and others (battery storage) are not NBT eligible, they are neither on that list or defined as renewable in the RPS Guidebook. This would be a conventional way of getting a multiple tariff facility.

### **Stay on NEM 2.0 by Separately Adding to Facility**

But aside from that, there is a specific NBT-MT provisions for adding more NBT eligible generation when the site already has generation equipment under another NEM agreement (such as on our site, there are already photovoltaics under NEM 2.0 agreement)

1) We could install a non-export relay on the new generation to be installed and allow the existing solar to remain on the old NEM 2.0 tariff. This would allow the current ~4kW of solar to export at higher price rates per kWh than will be possible on NBT schedules. City Farm will still have to make a Rule 21 application as their generation is significantly changing, and they would also be liable for PG&E standby (schedule SB) and departing load schedules which ostensibly adds cost. [PG&E's NBT Schedule Special Condition 4.g]

The description of this mechanism is located in the NBT Multiple storage section of PG&E's NBT Schedule, but we understand that we would still be operating under the NEM 2.0 tariff in this case.

### **Get on NBT-MT by Overstepping Paired Storage**

The conventional way to fall under NBT multiple tariff is as follows. We saw in the last section that under certain conditions battery storage can be added to a facility and the entire facility can remain on the NBT-PS tariff under a few different billing schemes. But if those conditions are not met and we still want to export energy from our photovoltaic plus battery facility, then we must take on the requirements for NBT-MT.

2) We would group all the solar generation together and have it collectively fall under an applicable NBT or while batteries are under non-export schedule. [PG&E's NBT Schedule Special Condition 4.e]

We note that we language in PG&E's NBT Schedule Special Condition 4.e says:  
"Customers who take service on NBT-MT by adding an NBT-eligible generator to a facility (behind the same utility revenue meter) with existing NEM/NEM2/NEMFC/NEMBIO eligible REGF(s) will be billed under NBT-MT, and all eligible REGFs will be combined into one Constituent Generator Group(s), which will be transitioned to and billed under the NBT"

We do not understand this to say that any customers who add NBT-eligible generation to a NEM 2.0 facility and transition to NBT will necessarily be on NBT-MT. We emphasize that this clause refers to "customers who take service on NBT-MT," and expect to be able to transition the facility collectively to another sub tariff, NBT-PS, or enact non-export as per Rule 21. Instead we interpret this clause to say that PG&E will not allow you to have a "Multiple Tariff" such that your old renewable generation group remains on NEM 2.0 while your new generation group is put on NBT, all REGFs will be combined into one group and put on NBT. I.e. there will be no simultaneous NEM 2.0 + NBT facilities under NBT-MT (or under any other NBT schedule).

This is an important point for PG&E's NBT Schedule to make because Rule 21 J.8 makes reference to single facilities with "multiple generators eligible for service under more than one Net Energy Metering (NEM) tariff schedule(e.g. NEM-1, NEM-2, NEMBIO, NEMFC)" and "combinations of multiple NEM eligible generators under different tariffs." Perhaps such NEM 1.0 + NEM 2.0 facilities were allowed at one point, and readers may interpret that that J.8 phrasing allows facilities to combine NBT with different generations tariff, but Rule 21 J.8 goes on to say that for facilities with generators eligible for multiple services "administration and metering requirements will be as specified in the appropriate NEM tariff schedule." In this case the NBT-MT tariff schedule disallows such a combination of NEM with NBT.

### **NBT-MT Requirements**

With that understanding out of the way, we can discuss the requirements for NBT-MT facilities. The big idea is that PG&E will only credit City Farm for power coming from renewable photovoltaic generation. To ensure this there are two options:

- 1) Install a non-export relay (again, we discuss certification/approval of non-export relays later) on the non-NBT eligible generation --the batteries.

2) Install interval net generation output metering (NGOM) onto the NBT eligible generation group --the photovoltaics.

NGOM as described in Rule 21 J.3 has a couple of purposes, but the one we see as relevant is for monitoring purposes --PG&E must categorize which electricity comes from the photovoltaic generation. J.3 lists “relevant factors” and directs one Electric Rule 22 for requirements. We will postpone discussion of these Rule 21 J.3 factors and Rule 22 requirements until a latter section dealing squarely with net billing metering.

### **NBT-MT Billing**

Regardless of which way the NBT-MT facility is realized, non-export relay or NGOM, the billing/crediting for the facility is described in PG&E’s NBT Schedule Rates Section F. As in PS case, a non-residential customer will use an otherwise applicable rate schedule (OAS) to set the import costs for their electricity from PG&E, this rate will be time of use (TOU) based. But the part relevant here is that only the renewable portion of the export electricity will be credited. In the non-export relay case, that will be all the exported electricity. In the NGOM case, that will be only the electricity measured by the meter[s] on the renewable generation portion. We repeat (from Paired Storage Options’ Analysis) that any multiple tariff facilities “may” be liable for schedule SB. Some (such as the NEM 2.0/Non-export described above in this section) will definitely be on SB, but we read PG&E’s NBT Schedule Rates (E) section to say that any others are potentially liable to it.

### **Potential CCA Hiccup With Multiple Tariff**

Finally, PG&E’s NBT Schedule Special Condition 4.f reiterates that facilities operating with a CCA electrical provider will only be able to participate in MT to the extent that the CCA offers. As mentioned previously, we are confident that CCCE will be able and willing to let us participate in a paired storage and multiple storage type schedules. Although we were originally skeptical they would support multiple tariff.

## **PG&E NBT Schedule Aspects Applying to both Paired Storage and Multiple Tariff Equally**

### **Confusion/Murkiness of Additional Metering Requirements**

Recall that we were confused in the section on Paired Storage (specifically additional metering requirements for Large AC Paired Storage). The requirements for additional paired storage metering were put in this language:

- a) “install an interval meter for the NBT-eligible generation, meter the load, and meter total energy flows at the point of common coupling; or
- b) install an interval meter directly to the NBT-eligible generator(s).”

Why would you choose to design a system with more meters if you simply put one on the NBT-eligible generators?

We were also confused that the summary table (depicted in Figure 30) from the Paired Storage section of PG&E’s NBT Schedule includes reference to NGOM even though there was no reference to requiring NGOM elsewhere in that Paired Storage section.

Further, the language about requiring NGOM in the Multiple Tariff section of PG&E’s NBT Schedule (see below) is similar to the language about metering in the Paired Storage section: one will receive credits only when “the customer has installed interval NGOM on that Constituent Generator Group.”

There is no further definition of NGOM given in the PG&E NBT Schedule, only that it must meet requirements of Rule 21 Section J... J.3 is titled “NET GENERATION OUTPUT METERING” (NGOM). It includes requirements which “may not apply” to facilities under NEM [NBT] tariffs, states that customers will not be required for NGOM if there are “less intrusive and/or more cost effective options, for Producer/Customer, are available for providing generator data to Distribution Provider,” and further directs one to Rule 22 for requirements for metering options. An aside, J.8 also maintains that J.3 requirements may not apply to certain NBT-MT facilities but does direct the customer to have metering “at the PCC and at each of the NEM eligible generator groups,” before directing the reader back to the NBT schedule.

PG&E’s Rule 22 is ostensibly about direct access (DA) customers, a class of customer who “procure its electricity directly from electric service providers (ESP)” and ESP, defined in Rule 1 (the document Rule 22 references for definitions) is “an entity who provides electric supply services to Direct Access Customers.” We do not understand ourselves to be DAs or ESPs,

additionally Rule 22 has no direct mention of Net Generation or Net Metering, but does reference another document Direct Access Standards for Metering and Meter Data (DASMMD). Perhaps we can apply Rule 22 G.1, H.1, H.2 and Rule 21 J.2 to say that PG&E should be able to own, install/maintain or provide metering data management (MDMA) services for us. In this case, we would communicate to PG&E that we would like them to provide these services by including reference to it on the one-line we include with the application form (see page 2 of form 79-1174-03, the Rule 21 application, explaining how we communicate this). All forms locateable at [95]. We then expect PG&E to use those Rule 21 section J.3 factors to decide what meter to install. The costs of any one of these services vs. another are not clear (although it is clear that we would be responsible for paying for them). Perhaps the professional company that enacts the project will have the resources and expertise to meet the Rule 21 J.3, Rule 22, DASMMD, Metering and Data Management Agent, ect... requirements and design with additional meters without incurring extra (undefined) cost from PG&E, but we do not feel it is responsible to do this definitely ourselves.

Because we are somewhat confused by what PG&E metering requirements we would design to, but perhaps see PG&E as willing to take some metering responsibility, we feel that our course of action, if designing with any additional meters (NGOM or otherwise), should be:

- 1) To indicate on our one line diagram where we would like/expect PG&E metering to be; for multiple tariff, at the PCC and at each renewable generator group; and the same for paired storage (if we choose to enact paired storage via metering)
- 2) Be open to the possibility that PG&E could want to change the meter's placement or number of meters.
- 3) Understand that we are not comfortable accurately estimating the cost of the metering

As a final note, this whole discussion in this section has thus far been about additional metering and complicated multiple tariff metering, as in not the meter at the PCC that already exists. As discussed in "Potential Complications to PCC Metering" (in order to round out Rule 21 J requirements) we affirm that we expect our PCC meter to be acceptable for paired storage (when using a PCS or non-export relay) baring minor and inexpensive tweaks. We likewise find it acceptable for non-export as a non-export facility should only reduce demand and metering requirements as the facility would no longer be under NEM 2.0. In any case the location of the PCC meter would be left undisturbed.

## Warranty mandate

PG&E's NBT Schedule Special Condition 3 requires that all equipment used either has a warranty of at least 10 years, or that the facility has executed an agreement to ensure proper maintenance and system performance for at least 10 years. We imagine the big ticket items we will be able to find with at least a 10 year warranty/ But on some of the smaller components it seems less likely. We expect that the retailer of the equipment, a local service or the professional engineering company that does the design/build could provide maintenance and ensure long term system performance (see appendix 1, the invoice from the installation of the current solar panels). But we will leave the specifics of such agreements to the professional engineering company.

As this seems a parallel mandate, we note that PG&E's Distribution Handbook 4.2 likewise requires "the customer must have a qualified testing firm perform retesting of the equipment according to manufacturer recommendations and not to exceed 6 years, or when requested by PG&E." We assume this would be part of the same agreement to provide equipment maintenance.

## Generation Capacity Oversizing

We will start by explaining that the CPUC and PG&E both mandate NBT facilities to be sized to offset their onsite loads [CPUC NBT 8.3.3, PG&E's NBT Schedule: Applicability, 28]. We understand that to mean the capacity of the NBT generation is limited to the customer's annual electric load. Specifically, the REGF's estimated annual production should be no larger than the last 12 months of total usage. (This is not spelled out explicitly, but implied by [28] along with the way oversizing is calculated by CPUC NBT Order (e) and PG&E's NBT Schedule: Applicability, see below).

But both the CPUC and PG&E allow for sizing NBT generation capacity 50% greater than that, if the customer can attest that their load will increase by 50% or more in the next 12 months.

Following CPUC NBT Order (e), PG&E's NBT Schedule: Applicability lays out that under the 50% oversizing, "the REGF's estimated annual production should be no larger than: 150 percent of the Customer's most recent 12 months of total usage" (there are other ways to do the calculator for special circumstances not relevant to us). The attestation is built into the NBT forms. We will fill out that relevant section in the forms and do our design with solar capacity

based on the last 12 months of electrical usage times 1.5 or the last 12 months of electrical usage times plus the expected demand of the new building, whichever is less.

## **General Mandates On Equipment**

### **Rule 21 section Hh**

According to Rule 21 E.4.d “All Producers are required to provide and maintain Interconnection Facilities... that meet Distribution Provider’s technical design and operating standards for Parallel Operation as set out in Section H or Hh, including any updates to those standards.

According to Rule 21 Section Hh “Section H shall continue to be used for interconnection of inverter based technologies until September 8, 2017. Following such date, Section Hh shall apply for interconnection of inverter based technologies.” Since we use inverter based PCS, we will be subject to Section Hh.

Section Hh declares that its requirements are meant to be consistent with UL 1741 SA (a supplement to UL 1741), which used Rule 21 Hh as a source requirement document and it has precedence over UL 1741 SA. This information along with phrasing from section P of form 79-1193-03 (the form for small NBT paired storage) and section 5.14 of form 79-1069-03 (the form for some other versions of NBT paired storage and NBT multiple tariff [95]) which say that inverter models and firmware versions that comply with Rule 21 section Hh can be found on the California Energy Commission website. We verify that the Solar Equipment Lists on this site includes many inverters that reference UL 1741 SA certification. [96]

We will take reference to that 1741 SA certification on that list to imply we can use the inverter as a component in our design (along with our best engineering judgment) such that it will meet Rule 21 section Hh requirements. Further, we now focus specifically on Hh.1.c, Hh.1.d, Hh.1.e, Hh.2.e, as we see the other Hh requirements as dealing more with specific devices’ capabilities and settings (items covered by UL 1741 SA certification) than an overall design (covered by Specific Section Hh rules as follows). The settings on inverters to meet all other applicable Rule 21 section Hh requirements will be elucidated in the PG&E forms we fill out as part of our theoretical application process. Broadly though, inverters come Rule 21 compliant and their default settings will meet the majority of Rule 21 Section Hh requirements.

Rule 21 Hh1.c says, at the point of common coupling, use equipment certified or listed as per NEC definition and ensure the breaker is one “being capable of interrupting the maximum available fault current expected at their location.” We originally thought that this would be within our scope, but later realized that we are not going to be changing anything at the PCC, we expect PG&E’s meter to remain and will not be altering any equipment upstream of a subpanel that branches below the main site breaker (see later discussion on main breaker location)

The part of Rule 21 Hh1.c that is relevant to us is a no single point of failure (fail safe) safety requirement: design such that the failure of any single device/component shall not compromise safety and reliability of PG&E's system (See also Rule 2 portion of "General Mandates" above and the 2022 CEC). We will address this more explicitly when we elaborate on the design.

Hh.1.d involves installing a manually operated and visible disconnect at point of interconnection when required by PG&E's operating practice. We understand those requirements to be found in PG&E's Greenbook manual and will address disconnects when we discuss the greenbook.

Hh.1.e involves submitting protective and control diagrams to PG&E for approval. We believe this can be additions to our basic one line diagram and will be addressed when we present our one line diagram.

Hh.2.e prohibits grounding schemes that cause overvoltage. We believe this refers to grounding that is insufficiently sized and installed or in ungrounded systems that overgenerate. [55, 61] We expect that the grounding provisions of the 2022 CEC should prevent this, if followed appropriately, and we will further discuss sizing and installation when discussing the CEC.

## Equipment Requirements Applying to Any Design

### Title 24 Section 110.0

Again, Title 24 colloquial name of the California Energy Code. The section we discuss here, 110.0, is about the mandatory requirements for systems, equipment or components that will be installed. 110.0(a) "General Requirements" states "the system, equipment, appliance or building component complies with all applicable installation provisions of Sections 110.1 through 110.12" to be installed. The only sections we see as potentially applicable are 110.1--Appliances and 110.11--Electrical Power Distribution Systems. Title 24 sections 110.0(b).3.A and 110.1(b) both call out directories/databases published by the California Energy Commission as meeting appliance certification/requirements. This is reassuring because we plan on using such a database to choose most of our system components. According to 110.1(a), any component we use not on that California Energy Commission Solar Equipment Lists will have to be outside the scope of equipment regulated by Appliance Efficiency Regulations, Title 20. In terms of tile 24 section 110.11--Electrical Power Distribution Systems, it only speaks about low-voltage dry-type distribution transformers (such as a current/instrument transformer), which we will likely have to verify efficiency of if we use, although there are exceptions for some classes of transformer.

We found many references to Joint Appendix 12 (JA12) of Title 24, which describes “Qualification requirements for battery storage systems,” and originally assumed that our battery system would need to be constructed with components that were compliant. However, JA12 speaks only to Title 24 sections 140.10 and 150.1(b) (sections describing mandatory solar and battery systems that can be installed alongside to reduce quantity of required solar capacity). We do not have a Title 24 requirement to put solar on a building (we are not designing a building) and thus do not need a battery system that meets JA12 requirements. Nowhere in the Title 24 certification mandates section that applies to our project (Title 24 110.0/110.11) is JA12 mentioned.

### PG&E Rules 2, 3, 15 and 16

PGE Rule 21 B.4 describes that or design meet “load aspects of storage devices will be treated pursuant to Rules 2, 3, 15 and 16.” [88, 89, 90, 91]

We believe the most relevant part of Rule 2 is section C.2.d describing minimum utilization voltages for non-lighting loads, loads must be rated to handle voltages, at their terminals, down to 90% of the nominal voltage of the line. For a load on a 208v line that minimum utilization voltage would be 187 volts and for a load on a 120v line that minimum utilization voltage would be 108v. Rule 2 reinforces that we are responsible for designing to maintain that proper utilization voltage (a bigger voltage drop than 5% voltage drop over our feeder/branch lines that the NEC mandates). This would imply that the voltage at the loads’ terminals will not fall to the rated minimum utilization voltage under normal circumstances but we will attempt to find devices rated to the minimum voltage anyway. Rule 2 reinforced that we are responsible for designing our protection devices between generation/storage in a fail safe manner (by using double throw switches for example, although we will more often have multiple breakers in series). Rule 2.G discusses that if the power factor of our loads is “low”, we are required to install power factor correction equipment. We do not expect to have a power factor that is excessively low, even though City Farm des have a motor, which is an inductive load. It seems unlikely that the power factor of the facility was too low to begin with because it operated for years before any generation was added. We are not adding any new inductive loads. But part of the requirements

of the smart inverter is to compensate for reactive power by supplying/absorbing it as needed, which would make this even less of an issue to consider (Rule 21 Hh.2.i).

Rule 3 is about how to make an application for service, how you shouldn't lie on application and that you should inform PG&E of material changes to your loads. We are intending to follow all of this. Rules 15 and 16 are about service and distribution line extensions. Neither of which we are planning on requiring.

### **PG&E's Certification Requirements: Those Covered By California Energy Commission Solar Equipment Lists and PG&E Lists**

PG&E's Rule 21 Section L deals with certified equipment; one of the checks in the Rule 21 Interconnection Application review process is that the equipment for installation is certified via the test elaborated on in L, and if not pre-certified then the equipment must be tested under those procedures. We are not going to be buying the equipment to run procedures on, nor do we have the option to build the facility and let PG&E run tests on it as a whole. So all the equipment we use must be certified as per Section L. Additionally, PG&E's NBT Schedule Section 3 requires that the entire generation facility meets Rule 21 Sections L.2-L.4 and L.7. However, that same paragraph of PG&E's NBT Schedule Section 3 declares that "Equipment on the California Energy Commission (CEC) list will meet this [Rule 21 Section L] requirement. This seems a little too easy, but on its face, that idea seems to be reinforced by Rule 21 solar and battery forms 79-1174-03D and 79-1174-03 H (see section on Instructions.D--page 1 of 8) [95]. Both describing generators and inverters as certified if system components are on the verified equipment list maintained by the California Energy Commission. This understanding will be cleaned up later under "Final Thoughts on Solar Equipment List."

### **PG&E's Certification Requirements: [Non-Export] Relays and Safety Switches**

PG&E's NBT Schedule Special Condition 3 was calling for its non-export relays to be approved by PG&E. PG&E Rule 21 Section L.7.a specifically calls for non-export tests of non-export relays. We again will find testing impossible by ourselves and do not wish to design a system that relies heavily on commissioning tests (tests on facility after parts have arrived/been installed) for verification. So we assert that the same need for certified equipment, discussed in

the section immediately above, applies to relays (non-export or otherwise). But this time we find no reference to relays in the Solar Equipment list. [96] Additionally, we read Rule 21 Section L.3.a, the Table L.1 and Section L.7.a.i to say that the UL 1741 style certifications only tangentially apply to relays and there is not really a standardized certification for non-export relays that PG&E recognizes in Rule 21. PG&E ostensibly maintains a list of pre-approved list of relays, we do find reference to such a list both PG&E's Interconnection Handbook (Appendix R) and PG&E's Distribution Interconnection handbook (the Distribution Interconnection handbook is not exactly the same thing as the Interconnection Handbook) [62, 43]. Looking through section G2 of the most recent (2022) PG&E Interconnection Handbook we do locate such a list in Tables G2-7 and G2-8 of that document [64]. We will take inclusion on those tables as PG&E approval.

We likewise find PG&E lists of safety (manual AC disconnect) switches on the PG&E webpage titled "Distribution Interconnection Handbook." [99] We apply the same logic and assume inclusion on the list implies PG&E approval.

### CEC: Approved/Listed Equipment

Section 705.6 of both the NEC and the CEC (of most recent year) call for some level of listing or approval of equipment used in "Interconnected Electric Power Production Sources" --another way to say generating facilities that operate in parallel with the grid. In the following, interactive equipment is that "intended for use in parallel with [grid] power source."

The NEC calls for interconnection and interactive equipment to be listed --that is, to be included in a list published by an organization acceptable to the authority having jurisdiction (shorthand to AHJ, the entity that permits the project), in this case the AHJ is San Luis Obispo. The NEC 705.6 section directs readers to a certification published by Underwriter Laboratories (UL), specifically the same UL 1741 we have been referring to time and again. We cannot find a list published on UL's website that accounts for every piece of UL 1741 certified equipment, but do find a place where devices can be checked for certifications on an individual basis.

The 2022 CEC calls for "All equipment shall be approved for the intended use" --approved by the AHJ, again San Luis Obispo. In addition for calling for interactive

equipment to be “listed for interactive function or be evaluated for interactive function and have a field label applied.”

After a couple rounds of searching through the county and municipality code sites, as well as standard google searches, we have been unable to find reference to an approved list of equipment published or referenced by San Luis Obispo. For the stated reasons above, we will have difficulty evaluating interactive functions of equipment ourselves in order to apply a field label. That being said, PG&E repeatedly references UL 1741, and the NEC specifically directs readers to that same certification. That UL 1741 certification is built into Solar Equipment Lists maintained by the California Energy Commission (the state level energy policy and planning agency [59, 96]). Title 24, and PG&E both explicitly and repeatedly reference the Solar Equipment Lists, as the list of equipment that meets their certification/approval standards. While we acknowledge that PG&E is not our AHJ, nor is the California Energy Commission, and the AHJ San Luis Obispo, may have slightly different or more strict rules on what equipment they approve, we find it likely that interconnection/interactive equipment found on the Solar Equipment Lists and being certified under UL 1741 (UL 1741 Supplemental A or B or UL 1741 CRD when applicable) will be acceptable to San Luis Obispo. For relays, as we discuss, we do not understand specific UL 1741 certifications to exactly apply. But we note that UL does have a tool that allows one to search products and see if they have a UL certification. [63] We will verify relays we choose of the PG&E tables as having a relevant UL certification, as our attempt to make our relay equipment as pallettable as possible to the AHJ.

### UL 1741, UL 1741 CRD, UL 1741 SA and UL 1741 SB and Final Thoughts on The Solar Equipment Lists

Not all UL 1741 certifications are equal, nor are they all relevant to the same kinds of equipment. The UL 1741 certification first came out in 1999 and has since been updated multiple times to address changes in distributed energy resources and the grid as well as interact with the IEEE 1547 as it updates. We understand from Rule 21 Section L Table L. (and its footnotes as well as source [60] that UL 1741 SA and SB are both “supplement” the basic UL 1741 test/certification that were added one after the other in order to certify inverters (as well as a host of distributed energy resource equipment). Supplemental A (SA) was added in 2014 and incorporated into Rule 21 to address grid interaction insufficiencies and SB was added in 2020 in response to the IEEE1547 update of the same year (ostensibly also to address insufficiencies). As of August 1, 2022, PG&E seems to be requiring UL 1741 SB style tests on

inverters used in “smart” (interactive/paralleling) functions. We do find this somewhat contradictory with the way we have interpreted some other clauses we have read in PG&E mandates. For example Rule 21 Hh. which is specifically focused on smart inverters refers only to UL 1741 SA, at no time mentioning UL 1741 SB. Similarly, and as discussed earlier, PG&E’s NBT Schedule and various forms seem to imply that mere presence on the California Energy Commission’s Solar Equipment Lists [96] will secure PG&E’s approval of a piece of equipment. To reconcile what we interpret as a conflict on the certification mandates of inverters we turn to the CPUC’s NBT Tariff (D.22-12-056) 8.5.4 page 166 which clarifies “This decision amends this direction in D.16-01-044 and clarifies that the utilities shall use the aforementioned sections of Rule 21 [Sections L.2-L.4 and L.7] to establish the certified and non-certified connection criteria [for inverters] for the net billing tariff eligibility in place of the CEC’s verified equipment list.” We read Rule 21 L.2 Table L.1 to mandate that, in 2023, for our smart inverter applications, inverters must be UL 1741 SB certified. We note that we see PG&E’s definition of anti-islanding as a supremely important part of this certification. Non-“smart” inverters are not on the Solar Equipment List, [96] but are mentioned on Rule 21 Table L1. We apply the same logic, holding Table L.1 as what determines if an inverter is approved by PG&E. The standard UL 1741 certification on the inverter meets most requirements, but we also will want them to reference some IEEE 1547 tests/certifications, if they have both, we will also view them as acceptable to the San Luis Obispo and thus acceptable as per the CEC. There is then the UL 1741 CRD. PG&E’s NBT Schedule Special Condition specifically calls for UL 1741 CRD certification on any PCS used in Paired Storage systems. UL 1741 CRD seems to be separate from the SA/SB supplementals, being issued in 2019 and not referred to anywhere in Rule 21. Since we find no specific reference to PCSs or UL 1741 CRD in Rule 21 section L, we are disposed to find a UL 1741 CRD sufficient to certify a PCS.

We propose that our course of action when choosing equipment should be:

- 1) Use the Solar Equipment Lists [96] for choosing solar panels and batteries without need for additional certification
- 2) Use Solar Equipment Lists [96] to choose a PCS an option that has UL 1741 CRD certification (if a PCS is in fact used)
- 3) Use Solar Equipment Lists [96] to choose non-exporting (and other smart) inverter options that have UL 1741 SB certification (this approach is backed up by PG&E’s Distribution Interconnection Handbook), regular inverters we will look to be UL 1741 certified and reference IEEE 1547 (if they are used).

- 4) Use PG&E lists to choose relays and check them against the UL certification tool, verifying they have a relevant UL certification (if they are used)
- 5) Use other PG&E lists where applicable for other equipment (such as when choosing disconnect switches) verifying both certification with a UL standard and verifying compliance with any specific and applicable CEC mandate (other than the mandate requiring AHJ listing)
- 6) Verify devices are rated to minimum/maximum voltage as per Rule 21 Hh

## **IEEE 1547-2018 (according to Rule 21)**

As briefly discussed we believe that much of IEEE 1547 is absorbed into UL 1741 and Rule 21 Section L, and we have a plan to comply with those mandates (see above). There ostensibly are elements of IEEE 1547 that Rule 21 does not speak on (such as Clauses 4.1.4.2 Distribution Secondary Spot Networks and Clauses 4.1.8.1 or 5.1.3.1). We do not understand City Farm to be on a secondary spot network nor did we locate those specific clauses in the IEEE 1547-2018. If the equipment has reference to IEEE 1547 we will consider IEEE 1547 satisfied.

## **Analysis on Choosing Non-Export, PS or MT**

We decide that choosing a Paired Storage facility is the way to go.

While a non-export facility allows for benefits to the PG&E Interconnection Request (guaranteed review under fast track and fewer initial screens to pass), its equipment requirements are just as much of a burden (if not more so) and it comes with billing losses. To enact non-export, the facility would need either a PCS or a non-export relay. These are significant costs, additionally the PCS requirement for a non-export facility are more stringent (it includes having an PCS OLR time of less than 2 seconds compared to the 10 second response time a paired storage PCS has to curtail export). But a big concern is that transitioning to a wholly non-exporting facility gives up the potential for export credits at all. The credits are not as large under NBT as they were under NEM 2, but they are still a financial benefit. Adding to that lack of a financial benefit is an ongoing financial cost. Having non-export makes us liable for schedule SB, which we want to avoid because of its additional monthly charges and additional requirements efforts to administer.

A possible option that addresses some of those problems would be to leave the existing solar as is and simply add the additional solar and battery storage behind a non-export relay (described in the multiple tariff section). This would allow some export credits to be accrued (at a higher rate), and retain most of the benefits to the review process we saw in non-export. The main downsides are that the newer solar generation is still not credited, and the City Farm would still need to purchase a non-export relay. But also there would be no lock in period that extends after the NEM 2.0 lock in is up. Similar to the NBT tariff lock in, NEM 2.0's rate schedule will run out (sooner than the NBT one) and then export rates will transition anyway. Based on current trends those rates are likely to have a calculation base that credits them less than they are credited even under NBT (the CPUC has lowered credit rates in both NEM/NBT updates). Also the facility would still be liable to schedule SB costs/requirements. We do not expect it to be liable for upgraded PCC or additional metering.

We find that NEM 2.0/non-export option is still preferable to an NBT multiple tariff facility. We expect that the export credits could be roughly comparable between the two options (the normal NBT billing accumulates smaller credits for all the solar export), and the multiple tariff facility is still potentially liable for schedule SB. Additionally, the facility will still need a non-export relay, or it will need the NGOM metering. We expect NGOM to cause PG&E upgrade cost, potentially monthly maintenance cost and more PG&E interaction during the application process (recall the part of the application where City Farm and PG&E are going to negotiate over costs). We are also hesitant to design on the basis of NBT-MT because we could not verify that CCCE will support billing under it.

We are so preoccupied with schedule SB because it will add to the monthly bill. Once the facility becomes liable for it, it will continuously reduce the (already somewhat thin) margin to be attributed export credit.

Moving on to paired storage, we find this the most flexible schedule to operate under. We could choose either to put in a non-export relay, a PCS (of relaxed requirements compared to non-export facility) or additional metering; choosing a PCS will secure the normal NBT billing or otherwise we could take multiple tariff style billing. As we mention we have lingering doubt that multiple tariff style billing will expose us to schedule SB, so we prefer to use a PCS. But another

option would be to limit the size of the paired storage to less than or equal to 10kW. We find this option the best. While we would have to take estimated billing and its (probably slight) underestimation of credit, we would still accumulate credit for the majority of the energy exported (at NBT rates). This is a negative compared to the NEM 2.0/non-export option, but should be offset by avoidance of schedule SB. We also be able to avoid having to purchase a PCS or non-export relay. We see this as a relatively big cost saving. We are confident that CCCE will support paired storage billing. Additionally, to assure ourselves that we would pass Rule 21 screen D, we wanted to keep the storage capacity low. Designing a paired storage facility with less than or equal to 10kW of storage capacity will best allow us to do that.

This analysis presupposes that the PG&E transformer is rated high enough to support the 9.6kW facility we design. If an NBT facility of our size does trigger a failure of Rule 21 screen D and/or a service upgrade, then we expect the NEM 2.0/non-export option will be the most cost effective.

## **General Mandates Specific to Overall Design and Site Plans**

### **Manual and Visible AC Disconnect**

As mentioned when discussing Rule 21 Section Hh, the facility needs a visible AC disconnect. The rules on this disconnect are described nicely in [66] PG&E's Greenbook 5.10.1. Its requirements depend on if the generation facility is connected on the supply side of the electrical service (between the meter and the main breaker) or on the load side. It is not abundantly clear to us what on which side the connection is on (we will discuss later confusion on where the main breaker is). On one hand PG&E's greenbook 5.10.1 calls for either a fused AC disconnect or "a dedicated, alternative generation breaker that came manufactured (e.g., solar ready) with the meter panel" if the generation is connected to the supply side. There is no existing fuse on the AC disconnect and we do not see how the meter panel could have such a breaker. The meter panel was manufactured and installed far before the solar generation system was. This taken together implies that the generation connects to the load side. But there is a sign on the PG&E meter that indicates that "Terminals on the line side and load side may be energized in the open position." This implies to us that if the main breaker is open the line (supply) side could be energized by the generation facility because that is the side that the generation facility connects to. Additionally, a requirements document that is linked to by section 5.10.1 of the PG&E Green book seems to soften the breaker requirement for supply side facilities (5.10.1 called for a breaker or a fused AC disconnect as discussed above in this paragraph). Instead of requiring a breaker that comes manufactured with the meter panel, it requires: "'solar ready' service panels designed with a dedicated alternative energy (customer generation) circuit breaker." This we do believe the facility to have (it is the 120/240v subpanel with a "PV Breaker"). Out of caution we will assume the more dangerous option is true, that the generator facility connection is made on the supply side. We do not believe that this will create additional requirements for us because the current facility already seems to have the signage and PV breakers required. But we will indicate it to the AHJ in our site plans. We clarify that fusible means that the device can have a fuse loaded in for added protection.

Additionally, the AC disconnect should be less than 10' from the PCC meter, in line of site of the meter panel (or include a map showing the location of the ac disconnect switch --this is our situation and we will have update the warning map as our equipment may not be located in the same places) and only disconnect the customer generation sources, not the customer loads.

[PG&E Green Book 5.10.1] The current map is posted on the AC disconnect and on the PG&E meter panel.

From a technical standpoint PG&E Distribution Interconnection Handbook requires the disconnect:

- a) Be rated for the voltage and current requirements of the particular installation.
- b) Adequately sized to handle maximum continuous loading and transient fault conditions.
- c) Includes PG&E approved markings on the switch that clearly indicates the open (off) and closed (on) positions
- d) Easily accessible by PG&E, when requested
- e) Installed in a safe and acceptable location that meets all PG&E working space requirements.

These requirements we expect to be able to meet and the other requirements the Handbook lists seem to be covered by any device that PG&E include on their pre-approved lists which are found in [99].

## Harmonics

Harmonics are an important consideration for a facility and for PG&E's grid. Equipment like inverters can create substantial harmonics that can distort the normal voltage and cause negative effects on adjacent customers served by PG&E [Rule 21 Hh.2.d]. While this is an important consideration and we potentially have the tools to model total harmonic distortion (THD) created by our system, PG&E makes multiple provisions to guard against it that we will follow. We plan on meeting the Rule 21 Hh mandates and using equipment certified under it and we will pass Rule 21 Screen O. These combined, appear to be enough to convince PG&E that our harmonic distortion is acceptable and we will consider that good enough as well.

## Rule 21 D.6

This section of Rule 21 calls for the facility to have things located such that PG&E personnel can reasonably access them. We understand that mostly to apply to the AC disconnect and to meters. We will design such that they are located in the open and not in any location personnel will not be able to access.

## Greenbook Clearances

PG&E's Greenbook has some sections on mandated clearances that could be important. We understand the relevant ones to us apply to service drops (the lines coming from the pole mounted transformer to the meter). To avoid any violation of this we will simply not design anything to be built above ground between the transformer pole and the meter pole (see below Figure 31).



*Figure 31. Clearance Area Around PG&E Pole Mounted Service*

## Bulk of PG&E Protection Requirements

We understand that the bulk of our protection requirements will come from this “DISTRIBUTED GENERATION PROTECTION REQUIREMENTS” document published in 2023 (an offshoot of the distribution interconnection handbook). [61] It provides more flowcharts and descriptions to determine what protection your system should have such that PG&E will be protected. We understand points 1-6 to apply to all distributed generation and paraphrase them here:

- 1) PG&E can obligate any facility to have direct transfer trip (DTT)

- 2) Every facility must have phase and ground fault protection, but may be exempted if
  - a) They aggregated fault current contribution less than 10% (of the service, see below for calculation)
  - b) and are expected to have (generator DC disconnect) trip due to anti-islanding function
- 3) Above exception 2)a) and 2)b) is not for non-certified inverters
- 4) DTT mandated for transmission level facilities
- 5) For a line section with all certified inverters, reclose blocking will not be required if the first reclose can be delayed to 10 seconds
- 6) If DTT already on site... not applicable

But then point 7 applies to inverter based generation (like we will have-- solar and battery inverters) of size <40kW (we will be below 40kW, so it applies to our facility). Point 7 releases us from the requirement for DTT and the fault protection of 2). As we are not going to be explicitly checking for phase and ground faults as per the CEC, we don't need protection relays. We are not expecting to use a recloser, once breakers on our circuit trip they must be manually reclosed. The rest of the document applies to larger inverter based systems, machine generation systems, and those connecting at a transmission or substation voltage level. So we understand that to protect our system, we will be able to get away with using an non-islanding (PG&E definition) inverter, breakers, and fuses. We note we will want a PV breaker, and the already existing main breaker. Having both allows for disconnect at different places, but we also expect it will fulfill the redundant protection requirement.

## Floodplain

According to Title 24 Part 2 Appendix G109.4, outside appliances (ostensibly electric ones) must be elevated above the design flood elevation. According to G104.3, if this elevation is not specified, which we do not find it to be specified anywhere, we can reasonably utilize data from another source such as a SLO Public Improvement Plan. SLO Circuit provided us with information directing us SLO Public Improvement Plans 04-0615 as a source of this information, and explaining that locating equipment 3' above the grade will suffice for floodplain requirements.

## **Title 24 TABLE 130.5-B MINIMUM REQUIREMENTS FOR SEPARATION OF ELECTRICAL LOAD**

This would be important if any of our panel boards or enclosures served more than branch circuits but we are in the strange position where none of them do. We will show this in our single line diagram, but the only place where multiple circuits branch is from the inverter and it does separate the battery and the air conditioning unit. If more air conditioning HVAC is added (if the new barn has HVAC for example)and if the service was upgraded to above 50 kVA perhaps then designer would have to work something out to accommodate this.

## **Site Plans**

\*PLANS/DOCUMENTS ARE STRICTLY FOR PURPOSE OF ACADEMIC PROJECT, THEY ARE NOT TO BE USED AS BASIS FOR APPLICATION TO ANY AUTHORITY WITHOUT DUE DILIGENCE BEING DONE BY PROFESSIONAL ENGINEERING ENTITY WHO SCRUTINIZE PLANS UNDER ALL APPLICABLE CODES/RULES/DECISIONS AND COMPLETE ALL NECESSARY STEPS TOWARDS ANY APPLICATION. THIS WRITER LIVES IN FEAR OF CPUC DECISION 21-06-026, D.18-09-044, AND D.20-02-011 AND DREADS CPUC BLACKLISTING THESE WRITERS OR THE CALPOLY INSTITUTION.

\*THIS REPORT IS AN ACADEMIC EXERCISE, WE DID NOT GET CITY FARM TO FILL OUT CALIFORNIA SOLAR CONSUMER PROTECTION FORMS AND ANY BUSINESS/FINANCIAL DECISIONS MADE ON THE BASIS OF INFORMATION PROVIDED HEREIN MUST BE DISCUSSED AND VERIFIED WITH A LICENSED PROFESSIONAL BEFORE BEING COMMITTED TO.

### **CEC Sections Applying Generally**

We are now in a position to get more specific and apply relevant CEC sections to the project, which we have thus far largely been ignoring. As noted, we review the CEC with the understanding that it is more specific in its mandates than the NEC and there should be no significant contradictions between the two that would prevent a system designed under CEC from being permitted under NEC (with only minor/facial alterations). Additionally, for the benefit of the senior project reviewer, we can link to a copy of the CEC in [92] but our reviewer[s] would have to create a profile to be able to access the NEC. Finally, the terms of use of the NEC document that we have been reviewing for our own information, explicitly prohibits the document's use for the purpose of creating derivative works. We would like to steer clear of any accusation of using it to create a derivative work and will thus not directly reference or use language from the NEC.

All the general mandates of the CEC will apply to us. But on a specific system level, we also understand that our facility will qualify as: a small PV system, making CEC 690 apply to us; an interconnected electrical power production system, making CEC 705 apply to us; and an energy

storage system, making CEC 706 apply to us. We will heavily reference those sections after we deal with some generalities here.

CEC 312.2 describes that enclosures for overcurrent protection devices and switches will be able to prevent water from entering and accumulating in the enclosure, and they shall be weatherproof. In our climate we do not understand weather-proof to really mean ice-proof/freeze proof. But we will endeavor to use NEMA 3R rated enclosures, those offer protection against ice, water, dust and protection for personnel from hazard internal to enclosure. We reference CEC 240.41 on moving breaker parts to justify protection of personnel from hazards internal to the enclosure.

We have noted before that some equipment is to be installed in readily accessible locations. In fact most/all equipment should be located this way. At some times requirements are more specific, but if not elaborated upon we understand mounted ~3' above ground in the open air and not behind any barrier, to be a readily accessible location suitable for equipment placement. We will locate all new equipment this way. This is not the same thing as clearance/working space requirements.

CEC 110.26(A)(1-3) calls for 3' of working space in front of equipment likely to require examination, adjustment, servicing, or maintenance (pretty much all of our equipment). The width of the working space in front of the electrical equipment shall be the width of the equipment or 762 mm (30 in.), whichever is greater. The work space shall be clear and extend from the grade, floor, or platform to a height of 2.0 m (6 1/2 ft) or the height of the equipment. As all the equipment is outside and none of it is facing anything the only issue really is the 30" width requirement. The new equipment and specifically the equipment mounted on the solar panel support structure, must adhere to these requirements.

CEC 705.45 requires limiting voltage imbalance for single phase power sources. We originally imagined that the 120/240 split-wire was not a single phase wiring system. After all, it connects across Line A and Line C and the voltage angles are 180 degrees out of phase with respect to the neutral line. But wires are not the same thing as phases (although the terms can be used imprecisely and interchangeably if one is not careful). The 120/240 split-wire really only connects over a single phase of the secondary of the transformer (see image in section about

PG&E service voltage). We found language in the CEC that describes a “single-phase, 3-wire system” that we understand to be the same thing as a split phase system. So CEC 705.45 will apply to our system. The CEC references a document that we are not going to pay for to read, but we imagine that the phases can be balanced, with the addition of the generating facility, if one was to rearrange loads on the main panel. [78] Sadly, we do not have access to the main panel schedule and will have to leave it to the professional engineering company to get inside the breaker boxes, catalog everything and ensure phase current balance.

We consider that 242.14 (B) will require a surge protection device downstream of the PV subpanel. But we are hesitant to view the solar panels as a structure. We will leave implementing any necessary surge protectors to the professional engineering company.

We will reference additional sections or additional subsections as they are relevant to specific parts of the system or to specific components.

## The Existing Renewable Solar Based System

### 2019 Installed Component List

We understand the existing system to consist of:

- 1) (12) solar panels with a 25 year warranty as of 2019 (invoice from installation Appendix 1)
- 2) (1) 3800 W inverter (1-phase 240 volt) with a 10 year warranty as of 2019 (invoice from installation solar Appendix 1)
- 3) (1) AC disconnect (site visit) which only has a one year warranty [73]
- 4) (1) 120/240 sub panel with (1) 1-phase pv breaker (see below information shared with us by SLO circuit electrical in Figure 32)

(N) INVERTER AT ARRAY
(N) UNDERGROUND PVC CONDUIT
(E) 200 METER PANEL
(N) AC DISCONNECT AT ARRAY
(N) 120/240 SUB PANEL AND PV BREAKER AT EXISTING BACKBOARD
(N) PV ARRAY (N.T.S.)

*Figure 32. SLO Circuit's Referenced Equipment*

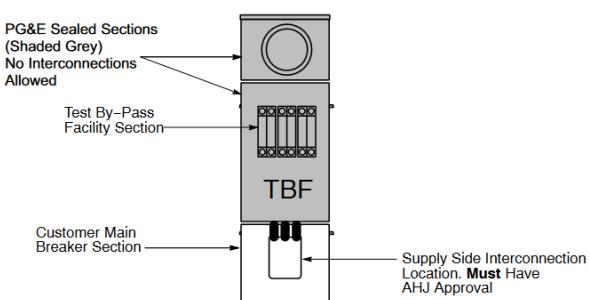
### Identifying Components' Locations and What Can Be Kept

Below, in Figure 33, we show the existing backboard with the PV sub-panel; we show the PV sub-panel close up.



*Figure 33. The Existing Backboard at City Farm and a Close Up on the PV Breaker*

We do not exactly understand the existing breaker/paneling system. We believe that generally there should be a “main breaker” that is directly downstream of the meter. This breaker separates the “supply side” of the system from the “load side” [74, 75]. We expect it to be either integrated into the PG&E meter as shown in Figure 34 on left side [75], or be the “breaker” part of a main breaker panel. We were able to locate neither on the City Farm property. The meter box seems to only have a section for a bypass facility (see Figure 34 on right side) and we do no not locate one on the back board (both large boxes seem to be for controlling/running the pump in Figure 35).



**Figure 3**  
Commercial Wall-Mount Meter Breaker Combination Service Panel  
Interconnections are not allowed in any PG&E sections (shaded grey)



**Figure 34. PG&E Drawing of Meter With Main Breaker Section and City Farm's Meter**

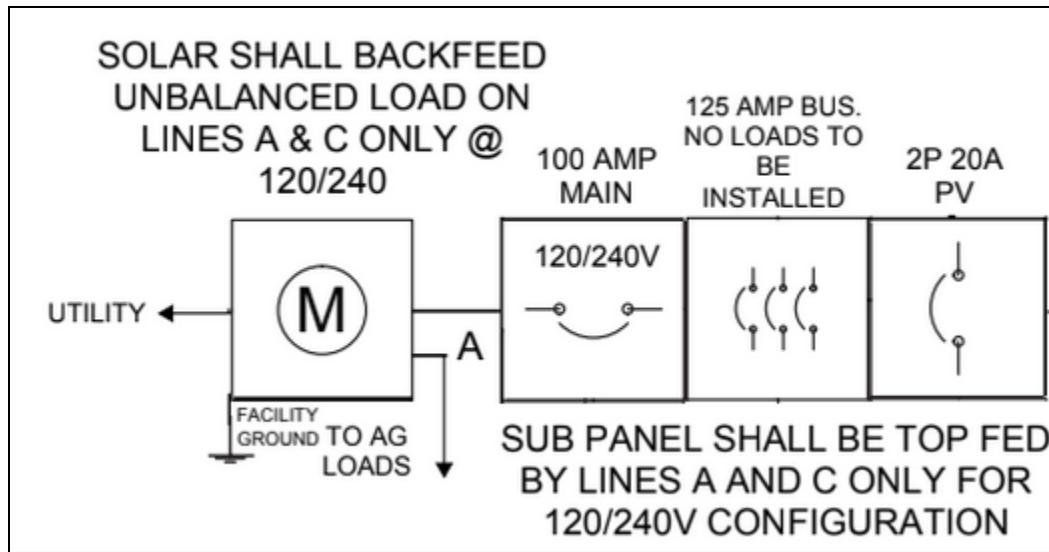


**Figure 35. The Existing Backboard at City Farm Noting Pump Boxes**

But we are confident that there must be a true main breaker (to disconnect all three phases of the service) that separates the supply and load side somewhere. Whether it is in fact in the meter panel, in one of the pump boxes, or somewhere else on the property, it must be present (in the meter box or in the left pump box on the backboard seems most likely).

Our confusion compounds here. From the documentation we receive from SLO Circuit they have a 100 amp “main breaker” that appears to be one phase (see Figure 36 and we note that the conduit (A) running to the breaker has only two hot conductors a neutral and a ground

--it is single phase 3-wire) and is separated from where the “AG Loads” are located. This is not what we understand to be a true “main breaker” as it cannot isolate the entire site from the PG&E service. The 125 amp bus pictured here does not seem to be the busbar on the backboard, shown in Figure 35. The bar shown in Figure 35 definitely has loads attached to it, for example, the pump controller load on the left of the backboard.



*Figure 36: Single Line of Existing (PV) Breaker*

To reconcile the single line diagram pictured in Figure 36 with what we see on the backboard and the SLO Circuit information we include in Figure 35, we assume that this 100 amp 1-phase “main” is the 120/240v subpanel (the one necessitated because we likely have a supply side interconnection). This was a little strange to us because the language of “main” and “sub” seemed contradictory and the image shows the subpanel to be rather small. But we now believe that the “main” of the “100 amp main” simply refers to the idea that in the panel there is a main breaker for the panel, so that the whole panel can be disconnected, in addition to the breakers for each circuit that the panel feeds. That panel is named as a “subpanel” on documents does not preclude it from having a main breaker for the panel. Additionally, the language describing “SUB PANEL SHALL BE TOP FED...” extending under all three boxes in the image above supports the conclusion that the single line above is depicting the 120/240v subpanel called out in SLO Circuit’s information and shown in the backboard image.

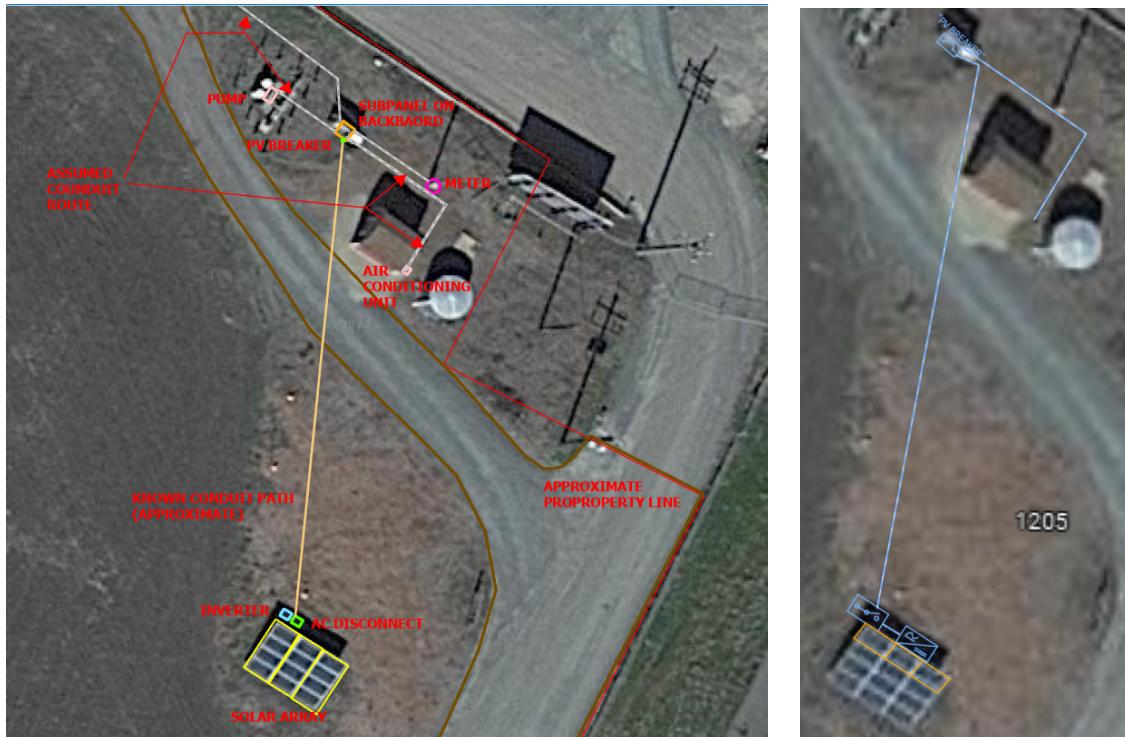
We do not have the model number of the 120/240 sub panel or direct access to it, we believe that we can still use it. Its bus is called out as being capable of tolerating 125 amps. The 100 amp 1 phase “main” breaker pictured above should be large enough to remain even with our

upgraded system (we are not expecting our additions to allow the generation facility to export anywhere near 75 amps at 240v). We do not believe that we should keep the “PV breaker”, it will be rated too small to allow the current that the upgraded generating facility will deliver. But simply replacing it with one of a higher rating should be fine, breakers with ratings of comparable magnitude should all fit into the standard breaker space.

We will want a new AC disconnect rated at higher current. [73] We will need a new inverter, this one will certainly not be able to accommodate any more solar panels (or battery storage). We should be able to keep the solar panels as they are warranted until 2044, ideally leaving them where they are and connecting them to the new inverter. We do not expect to keep the conductor running from the PV sub-panel to the AC disconnect and then to the existing inverter (or the conductor from the inverter to the existing panels). We will want to run new conductor along the same route from the PV subpanel to the site of the solar panels, but the existing conductor will be sized too small for the current the new inverter is capable of. We also do not expect to utilize the conductor running from the existing load panel to the air conditioning unit that will be put on the back up output of the new inverter.

### Existing Site Plan and Demolition Plan

Figure 37 is an image from google maps with outlines of equipment layered on top. Note that we only know the location of the conduit going from the PV breaker to the AC disconnect. All other conduit (to pump, ac unit, tractor charger, and additional loads) is guessed at; we also guess that the breakers for the other loads are located in one of the other panels at the backboard. We will use the image in our site plans as the basis of the demolition plan. This second plan shows what equipment will have to be removed.



*Figure 37. (On Left) Existing Equipment Site Plan and (On Right) Demolition Plan*

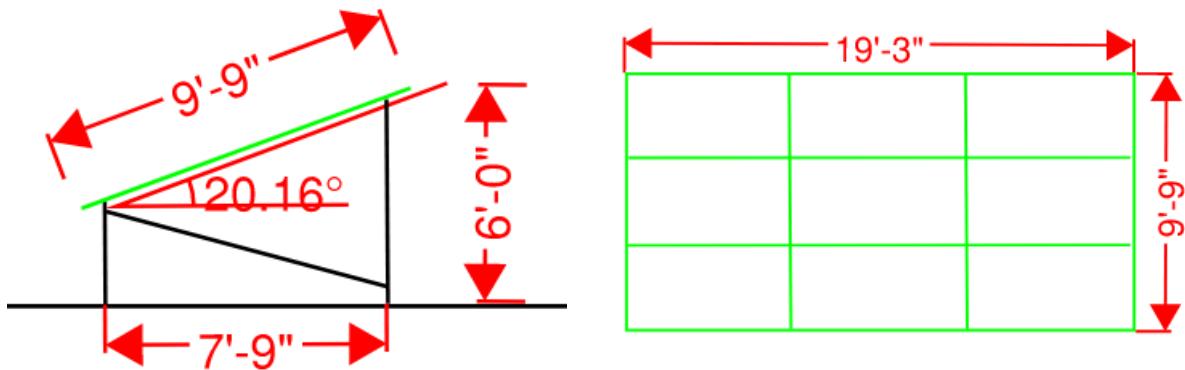
## New Components, Their Locations and Motivations

### Panels (solar)

Many inverters prefer that all solar panels attached to the inverter be of all the same kind, so it makes sense for us to continue to use the same Trina TSM-330-PE14 modules. The specific model TSM-330PE14A vs. TSM-330PE14H is not noted by SLO Circuit, but we believe based on dimensions and electrical specifications, that they use TSM-330PE14A. We verify this model number is on the Solar Equipment List [96] and has the appropriate UL certification and we are confident in using these for our design.

We will want approximately 9240W from the panels. 27 TSM-330PE14A modules equates to 8910W and we will then be able to put 27 modules on 3 strings. Each string will have with  $45.8 * 9 = 412$  OC voltage and  $37.4 * 9 = 336$  max power voltage, the inverter must be able to handle this voltage.

The existing solar panel support structure should be able to accommodate 3 rows 3 panels instead of 4 rows of three panels. The bars that connect to the panels are about 7'9" apart and three panels stacked lengthwise will be about 9'9" apart, leaving a foot of overhang above and below the connection bars (see below Figure 38 for approximate system drawing of structure in black and panels in green). We will need two more solar panel support structures, but we will leave it to the mechanical people at a professional engineering company to look at the design of the existing structure, verify it is structurally sound and create a detail on how to assemble new ones. We will simply use the height and footprint of the existing structure to determine the most appropriate places to locate the two new solar panel support structures.



*Figure 38. Solar Panel Support Structure and Solar Panel String's Height/Area*

We will orient the new panel structures parallel to the existing ones, approximately 220 degrees from true north (see below Figure 39, our approximation measures  $360 - 143.5 = 216.5$  degrees from true north).

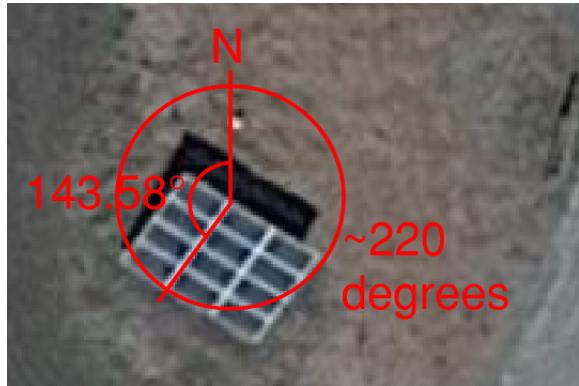


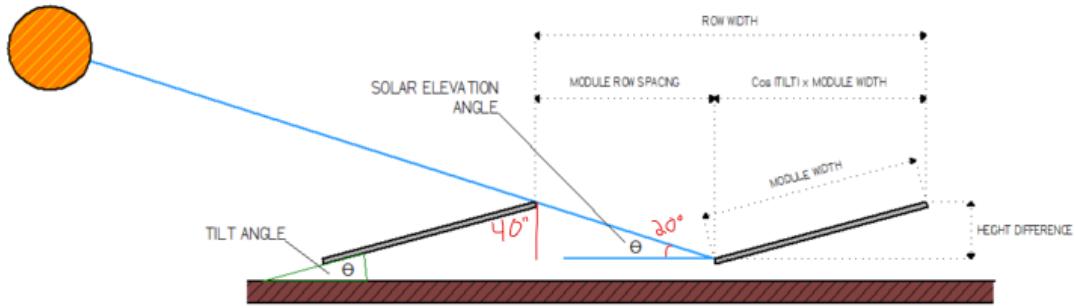
Figure 39. Solar Panel Azimuth Angle

We will likewise specify all the panels at the same 20 degree angle that the current panels use. We simulate altering the angle +/- 10 degrees but it does not seem worthwhile to alter the existing panel support structure for such a marginal difference in energy generated.

We do not locate any structure that could shade the panels (except for the panels shading ones behind them). Therefore we will plan on leaving space between the individual panel structures. To calculate the amount of space in between the panels we will first calculate the height difference between the top and bottom of the panel. This is some simple trigonometry, looking at Figure 40:

$$\sin(20) * 117 \text{ inches} = 40 \text{ inches} = \text{height difference}$$

We note that this value would imply that the bottom of the panel dips to 32" above the ground, which is below 3'. We find this to be below the plane that we were trying to keep all the electrical components above. We do not believe that the panels are made of water resistant materials so this would seem to be an issue. But on the other hand, the building plans that indicate that height for the solar panels were permitted so there is probably an aspect that we misunderstand, and we will assume that this elevation for the solar panels is acceptable.

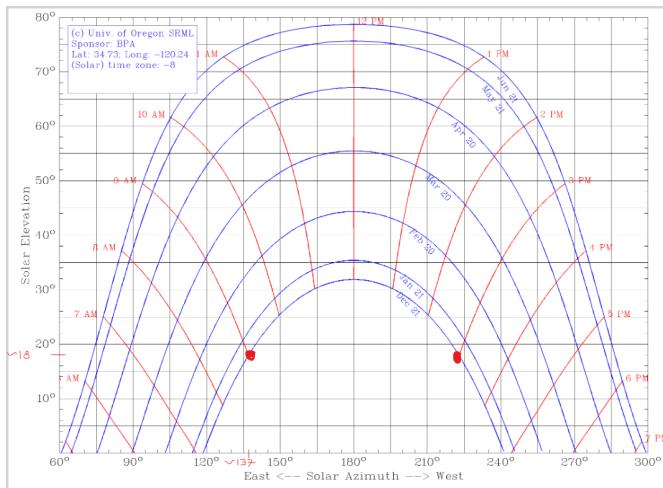


**Figure 40. Solar Spacing Angles. Credit Greentech Renewables**

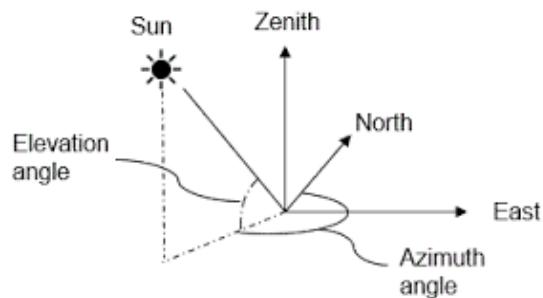
From there we use a University of Oregon program to chart solar elevation over half the year between the two solstices (the other half will be a reflection) at the latitude and longitude of San Luis Obispo. The result is shown below in Figure 41. At 9 am, when we generally will start getting good sunlight we notice the solar elevation is about 18 degrees and an azimuth correction angle of:

$$180 - 137 = 43 \text{ degrees}$$

See below Figure 42 for an image of what that means, the sun's beam would be approximately normal to the panels face if it was drawn in. We recall that the height of our panels (the topmost section is the part that will cast shade the farthest) will be approximately 6' above the ground.



**Figure 41. University of Oregon Program's Solar Elevation at City Farm**



*Figure 42. Explanation of Azimuth Angle. Credit Keisan Online Calculator*

The rough distance that the shadow will reach (using more simple trig, see Figure 40) equals  
 $40''/\tan(20) = 109.89'' = 9.15'$  = *module row spacing*

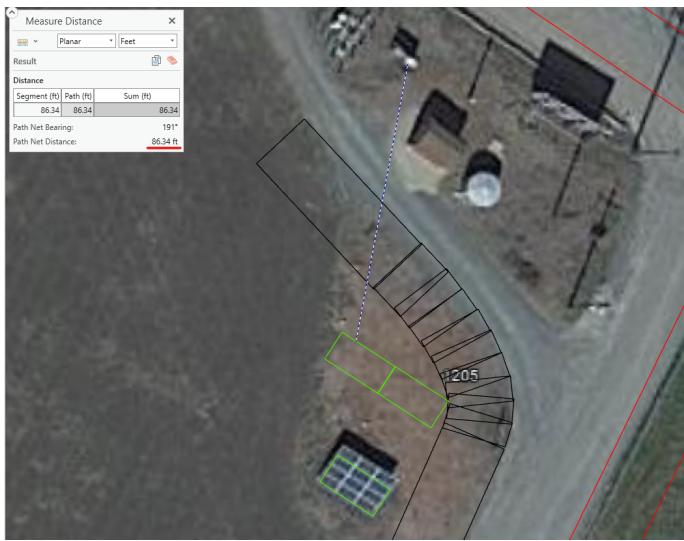
From there we correct with a factor that takes azimuth correction angle (43 degrees) into account. According to [76], the minimum spacing is then

$$109.89'' * \cos(43) = 80.36'' = 6.6' = \text{minimum module row spacing}$$

A SDG&E power point recommends a row spacing of about 2.5 times the height of the panel structure (~15' in our case). [77] We find it likely that this does not take into account that our panels are lifted so far off the ground even at their lowest point. Still there is a big difference between 15' spacing and 6.6' spacing and we are inclined to go with a value between them. We find the uncorrected module row spacing we calculated to be an appropriate value and will use a spacing of 9' between modules.

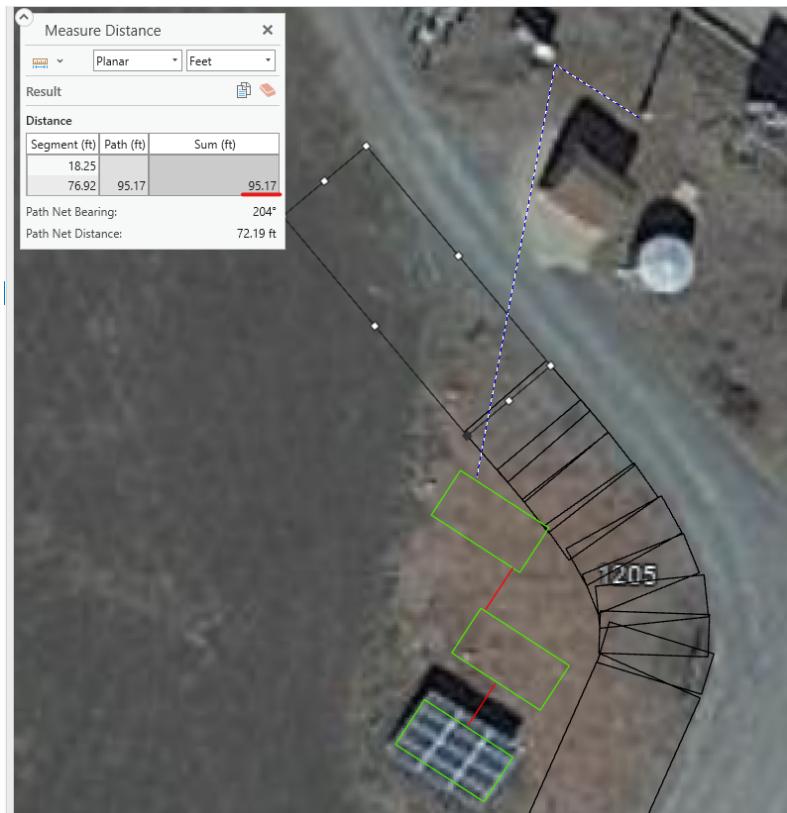
There are a few other considerations to manage when placing the solar panels. We notice that the existing panels are well set back from the road, ~25'. This seems prudent as there could be large agricultural vehicles unable to make sharp turns and thus cut into the corner and run over the cleared area where the panels are located. We will endeavor to set our panels 20' back from the road. On the other side of the solar panel space there is a tenant who uses a tractor to till his plot. We want to keep the solar reasonably set back from the path of that heavy equipment also. There is an additional consideration, we are planning on mounting the inverter on a leg of a solar panel support structure and the inverter can be a maximum of 98' from the main breaker. We will elaborate on why that is in the section about the inverter but will take it into consideration now.

Taking all of that into account, we could recommend a site layout as shown below in Figure 43. We use green boxes to denote the solar panels' areas, while the black boxes show where 20' from the road is.



*Figure 43. Possible New Solar Panel String Locations at City Farm*

Except that we have to account for the possibility of the site's main breaker being at the meter. If that is the case then we will encounter an issue when attaching the inventor's current transformers (CTs) to the main breaker box. The inverter we choose (elaborated on in "Inverter/Control" section) will only come with 98' of conductor for its CTs and at that length they won't quite be able to reach from the meter to the inverter (we plan on mounting the inverter on the solar panel support structure). We will have to use the following layout, which in addition to looking grosser, will mean that the conduits from the inverter to the panel strings will be uneven. This could imply different levels of voltage drop, but we may be able to minimize the issue with wire sizing and we expect the invert to deal with any remaining difference.



*Figure 44. New Solar Panel String Locations That Will Be Used, With Approximate Distance From Inverter To Main Breaker*

## Inverter/Control

We will need to have a non-islanding inverter to properly protect PG&E workers and their system in the event of grid deenergization. We therefore will have to have a smart inverter which is certified under UL 1741 SB. As we said, we will want it to be hybrid, supporting battery and solar panels, and we want it to be single phase, outputting 240v. Because we are planning on using the same subpanel with a 125 amp bus, the maximum output power/current it can have is 9600W or 40 amps (at 240v). We will search for inverters with a maximum power of 9.6kW and a minimum power of 8.7kW, the power used in our ballpark simulation. It should be capable of accommodating about 9kW of solar input over 3 to 4 strings, and capable of accommodating about 5kW of battery input.

We find 3 inverters that meet this basic description and that we liked.

- 1) Sol-Ark's Sol-Ark-8k-48-ST
- 2) Fox-ESS's AC1-9.6-US

### 3) GoodWe's GW9600A-ES

However, we are unable to find a retailer that will simply provide us a cost for Fox-ESS's AC1-9.6-US. We could communicate with them further and get a quote from them, but find the fact that their product is not sold on invertersupply.com perhaps indicates that their product is less widely used. We will disqualify them for this reason.

Of the remaining two, a cursory glance at their solar capabilities implies both the Sol-Ark and GoodWe offerings can support what we are looking to do. But we will do the explicit calculations here on the inverter we eventually choose.

We will use 3 strings of solar panels with 9 modules each. The GoodWe inverter has 4 multiple power point trackers (MPPTs), so will be able to independently control that many strings. Each panel's operating voltage is 37.4v and open circuit voltage is 45.8v. To satisfy CEC 690.7 we calculate the maximum voltage taking into account San Luis Obipso' lowest expected ambient temperature of 33 degrees fahrenheit. To do so, we multiply the voltage by 1.1 (resulting in a max open circuit voltage of 50.38v). Multiplying the unmodified values by the number of modules per string (9) gives a string operating voltage of 336.6 volts and a string open circuit voltage of 412.2 volts. The max input voltage of the GoodWe inverter is 600 volts, so this will be safe. The nominal input voltage of each of the GoodWe's MPPTs is 380, but has a range between 80 and 550 volts so a 9 panels string operating at 336 volts will be acceptable. The short circuit current available from each panel is 9.28 amps. The short circuit current that each MPPT can deal with is 15.2 amps. This is more than 150% of each of the strings' short circuit currents.

There is a significant difference in price; the GoodWe inverter is listed at \$4,305 while the Sol-Ark costs \$6,348. We find the \$4500 range is more reasonable for inverters of this size based on a few others that were slightly outside of our output power rating range. But we want to examine some of their other attributes before making a final decision.

### Battery Aspect

The primary and significant difference that we see is in the accompanying batteries. The GoodWe inverter has a nominal battery voltage of around 400v DC. This seems huge (although there were other similarly sized inverters that had similar battery voltage). Of the batteries the

GoodWe approves for use with its system, we find only one that is also on the Solar Equipment List [96], the RESU 10H Prime (which runs \$6000 itself). Meanwhile the Sol-Ark inverter has batteries that operate at a nominal 48v. Of the batteries that the Sol-Ark approves, there is also only one listed one, the PHI3.8 48V 60 VTE BRK. These run \$2500 and we would likely use three of them (for a total of ~\$7500). So the costs for the Sol-Ark based system are building in relation to the GoodWe system. Both batteries can get us to about 5kW of battery input/output power, so they are equal in that regard. There is a slight difference in kWh capacity. The RESU battery (that goes with the GoodWe inverter) has a slightly lower 9.6 kWh than the three PHI3.8 batteries (which go with the Sol-Ark inverter) which collectively have a capacity of 11.5 kWh. This is not significant enough to influence the decision much.

What is going to influence the decision is a determination of where the batteries are mounted and how they can be accessed. The batteries (like all other electrical components) must be kept above the design flood elevation; they must be mounted on something, the PHI3.8 are only 75 pounds and could likely be attached to the existing and new solar panel support structure. The RESU is over 240 pounds and likely cannot be mounted as such. Another consideration though, the PHI3.8 batteries do not indicate that they are NEMA rated for outdoor use. We might expect City Farm to build a structure to hold their batteries above the ground and catch any possible battery leakage, but we do not expect them to build a full structure to house their batteries. Thus disqualify the PHI3.8 batteries and the Sol-Ark inverter.

Although, we will remind the reader that City Farm has a secondary function as a teaching facility. With elementary children poking around, having a 400v DC battery could be unsafe and we believe there should be some means to prevent them from having access. We will indicate where we would like the battery to be located on the site plans, but as neither of us have taken structural engineering of any kind we will leave it to the professional company to design a means of elevating the large battery. We will also indicate our plans that we recommend some low fence or child proof measure should be added to their battery elevating structure. In fact there is potentially a CEC mandate (CEC 110.27(A)(2)) to guard against “live parts” of the battery by means of “permanent, substantial partitions or screens arranged so that only qualified persons have access to the space within reach of the live parts.”

We will use the GoodWe inverter.

## GoodWe Inverter Features

### **Operating Modes**

Generally the GoodWe inverter will have 4 operating modes that it can switch between[97]

- 1) Mode 1: When there is solar energy generation the inverter optimizes energy flow for self consumption, powering loads from solar. Excess energy is used to recharge batteries and any remaining energy is exported to the grid
- 2) Mode 2: When there is no solar energy being generated, but battery power is sufficient to power loads, the inverter optimizes for the battery to do so, in addition to using energy from the grid as needed.
- 3) Mode 3: When there is a grid issue and the grid is de-energized, GoodWe will detect this (via two CT transformers) and go into backup mode. It can power loads connected to its backup load output.
  - a) The system will need an auto-transformer to support backup loads that require 120v (as opposed to 240v). We will use such an auto transformer.
  - b) Some inverters do mention the need for an external device (such as an Automatic Transfer Switch) to break the connection to the grid. We note that none of the GoodWe inverter documentation calls out such a need. We interpret this lack of requirement for external devices (along with the UL 1741 SB certification of a grid interactive inverter) to indicate that the inverter has an internal means to safely break connection to the grid if it has been de-energized.
- 4) Mode 4: At certain times of day set by the user (times when site load is minimal 12:30 am-3:30 am) the battery can charge from the grid. The maximum power draw of the inverter is also controllable, if the service transformer is smaller than we assume and the inverter load needs to be decreased to operate the system safely (page 32 [98]).

### **Safety Features and Compliance With Mandates**

We will go down a list of integrated safety features that the GoodWe inverter has and how they are relevant to the CEC. CEC 690.4B requires evaluation for application and CEC 705.6 (and 706.16(B)) requires listing for interactive function, (as discussed in the UL 1741 section) these are both meet by the UL certification. CEC 690.11 requires arc-fault protection on the PV DC circuit; the inverter has this integrated. CEC 690.13 requires a means of disconnecting the PV DC circuit/system from all other wiring systems. The inverter has one integrated that we believe meets all the sub-requirements, it has a accessible disconnect switch and its rated above the

fault currents for the solar panels. This PV disconnect will function alongside a battery breaker to fulfill CEC 706.16 (A). We understand that the anti-island protection and AC overcurrent protection (GoodWe data sheet appendix\_\_\_\_) of the GoodWe inverter along with its UL 1741 SB certification and all of the overcurrent protection devices we include, allow it to comply with CEC 705.70 as being a microgrid interconnection device.

The inverter also has an AC bypass switch. In the event that the inverter becomes nonfunctional, the switch can be activated and the grid will be connected directly to the backed up load. Because this is to be used when the inverter is non-functional, we expect that this will disconnect the grid from the inverter's inputs, but did not find this specifically called out in any documentation.

We do find some conflict with the stated on grid output AC voltage range of the GoodWe inverter (211 to 264 @240v) with the way we interpreted Rule 2's voltage mandates (228 to 253v at 240v) and the further GoodWe inverter claim to be Rule 21 compliant. We understand Rule 21 to make explicit reference to Rule 2 and thus being Rule 21 compliant should imply Rule 2 compliance. Maybe we can reconcile this by explaining that the inverter rating implies that the inverter will be able to support abnormal PG&E voltages in the range that it gives (even extending that support to voltages PG&E does not expect to push onto the site). After all, it does not seem plausible that our small inverter will be able to significantly change the voltage of PG&E's distribution system.

To satisfy the CEC 706.33 (B)(3)(b) requirement to have a second independent means of controlling ESS charging, we have a hard time. We find it unlikely that the expectation is to purchase an entirely separate UL listed, PG&E approved, controlling device of near equal cost to the interactive inverter. In fact, the inverter manual specifically disallows for connections of multiple controlling inverters on one battery. But we are at a loss to what a simple device to accomplish this would be. Perhaps we can explain that if the GoodWe inverter were to fail, the battery breaker could be manually activated to control the charging of the battery (by not allowing charging). This does not seem likely to be what the requirement calls for, but for a better solution we must leave the issue to the professional engineering company.

## GoodWe Transformers

In order for the GoodWe inverter to detect grid disconnection and enter into its operating mode 3 (the mode compliant with PG&E non-islanding requirements where the inverter does not push electricity back onto PG&E's de-energized grid), the inverter will have to monitor the PG&E connection in some way. To do this, the inverter comes with two current transformers included. While we could not find reference to the model of the current transformers and thus could not directly verify that they have an appropriate certification. But the fact that the GoodWe inverter is listed as UL 1741 and thus passed UL non-islanding tests that are ostensibly only possible if the inverter has these current transformers attached, indicates to us that the current transformers are acceptable under UL and will be acceptable to the AHJ.

The current transformers (CTs) are meant to be installed directly downstream of the main breaker on lines A and C (the lines that make up the split phase 120/240v section of the system). Again, we do not know exactly where that main breaker is, although we are reality sure it is included in a box either on the existing backboard or in the metering box, a certified electrician opening up both boxes should be able to quickly locate it. In any case though, the CTs are to be connected rather far away from the inverter, we measure between 140 and 170 feet away from the location of the current inverter depending on the location of the sites' main breaker. Unluckily, the GoodWe's manual asserts that the CT's cables can extended to 98 feet at maximum. This will require us to relocate the inverter to a closer location. We find it likely that we will want to mount the inverter on a solar panel support structure (the same way the existing inverter is mounted). So we out a new panels support structure closer to the backboard/meter panel. We measure it to just squeak by at 95'. See section about solar panels above.

## Associated AC Disconnect

This device is mandated by CEC 690.15, 705.20, and 706.15 in addition to Rule 21. It will be within 10' of the equipment it disconnects (we understand this mainly to be the inverter). It does not need to have an interrupt rating, so it will be marked "Do Not Disconnect Under Load," although it will be rated to at least the maximum circuit current, available fault current, and voltage. It will also be marked with its nominal voltage and available fault current as well as an arc-flash label in accordance with acceptable industry practice, and the date the calculation was performed.

It will be listed for the application. It will be able to be locked in its open position. It is not to be marked "PV SYSTEM AC DISCONNECT," the PV subpanel is already marked with this language marking.

We will spec Eaton's fusible two-pole three-wire DG222NRB 60 A 240v (three wire because we will have to feed the neutral wire through it). It comes from PG&E's pre approved list and has both UL and appropriate NEMA listings. Because of CEC 690.9 (3)(3)'s mandate that inverter output conductors be protected from overcurrent at both sides, we will spec a fuse of the same size as the PV breaker to be fitted into the AC disconnect, even though we understand PG&E not to require one. The disconnect device will be able to be locked in its position.

## **Electrical Paneling and Breakers (the protection system)**

We will start with a breakdown of all the CEC sections on breakers and panels that we see to apply (as they are relevant and have not already been discussed), then have individual discussion about all the electrical components we specify. We understand the CEC to have stringent safety requirements. We see the way it mandates overcurrent protection to be a fulfillment of the PG&E Rule 21 Hh1.c redundant protection requirement. As we break down the overcurrent protection rules we will either quote or paraphrase the language of the section then add our understanding of its application below and indented; we give an example here.

### **CEC Section XXXXX**

(Sub-section Y) A direct quote of the text will go here. Or some times we will paraphrase the text and also put that here.

Our understanding of what the text calls for and its application to the project will go here.

## **Section 240 on general overcurrent protection**

### **240.4**

(B) Conductors shall be protected against overcurrent in accordance with their ampacities specified in 310.14.

We will do this unless another section specifies a breaker be larger/smaller.

### **240.15**

Circuit breaker or fuse is needed in series with every ungrounded conductor. When they operate, they will do by opening all ungrounded lines in the conductor.

We will have breakers on all lines unless we find an exception overruling this. We will specify breakers with appropriate numbers of poles.

240.21

Breakers for ungrounded conductors will be located at point where conductor receives supply.

We will follow this if there is not an exception

(H) There is an exception for battery conductors that loosens location requirements.

## **Section 690 on PV system circuits**

690.8 circuit sizing and current (solar PV)

(A)(1)(a) the maximum PV source current is the sum of the short circuit current ratings of the PV modules connected in parallel, multiplied by 125%.

In our case that is 9.28 amps across 3 parallel strings. That results in a maximum current  $9.28 * 3 * 1.25 = 34.8 \text{ amps}$ . This is the same as the PV output circuits' current.

(A)(1)(e) the inverter output current on the circuit to the service is the inverter's continuous output current rating: 40 amps.

690.9 overcurrent protection (solar PV)

PV dc circuits and inverter output conductors shall be protected against over current unless CEC 690.9 (A)(1):

"1) The conductors have sufficient ampacity for the maximum circuit current.

2) The currents from all sources do not exceed the maximum overcurrent protective device rating specified for the PV module or electronic power converter."

We believe that we can size the PV DC conductor to be this big (the PV short circuit current and operating currents only differ by an amp) and the GoodWe inverter has the rating, for all of its PV source strings, to handle the maximum fault current the PV source panel strings are capable of even if multiplied by 125%. We understand this to mean that the solar panel DC circuit will not need a breaker. We note that because CEC 240.3 directed us to CEC 690 for overcurrent protection for PV systems equipment specifically

(and not to either 705 or 706), we understand the 690.9 (A)(1) exceptions to overarch the 240.15 requirement that a circuit breaker/fuse be in series with each conductor.

As we note when discussing the AC disconnect switch, we protect both sides of the inverter output conductors as per CEC 690.9 (A)(3).

Overcurrent protection sized to not less than 125% the max current calculated in 690.8(A)

We do not understand there to be a need for a breaker on the PV DC circuit, but for the circuit from inverter to the service the calculation is as follows  $40 * 1.25 = 50$  amps breaker/fuse rating.

## **Section 705 on electrical production systems interconnected to the grid**

705.11

(C) There will be overcurrent protection integral to the AC disconnect sized by 705.30

If we had not calculated the protection rating for inverter's connection to service in 690.8(A), we would have in 705.30, they come out to the same number). This is a rating of 50 amps. We will accomplish this by putting a fuse in the AC disconnect.

705.16

Consideration shall be given to the contribution of fault currents from all interconnected power sources for the interrupting and short-circuit current ratings of equipment on interactive systems.

We believe that we already mention that the interactive inverter has the capacity to deal with the short circuit current available from the solar panels. The RESU 10h prime describes that it has its own short circuit protection features, and has a peak discharging current of 20 amps. This is below the inverter's continuous charging/discharging current rating of 50 amps. The inverter should not be able to put out more than ~60 short circuit amps [82]. This should not significantly contribute to frying any breakers (or the AC disconnect) upstream of it. But should also trip the 60 overcurrent protection

705.28 Circuit size and current

(A) Where not elsewhere required/permitted the maximum current for the circuit shall be the continuous output current rating of the power production equipment.

Because 690.8 and 706.30 speak on the requirements for the inverter circuit outputting to the service, the PV DC circuit, and the battery circuit, we will only apply this section to the circuit from the inverter to the back up load panel.

The inverter output current on the circuit to the back up load panel is 40 amps, albeit at 240 v. We clarify that even when only one 120v backup output line is used the inverter can only push 40 amps on that 120v line as described in the inverter manual.

#### 705.30

Power source output conductors (defined as conductors between power production equipment and service equipment) shall have overcurrent protection.

Circuits connected to more than one electrical source shall have overcurrent devices located to provide overcurrent protection from all sources.

We believe that we already meet these requirements with our design to 690.9. We read the first part to be about the conductors between the inverter and the service, the section of which we take responsibility for is between the inverter and the PV sub panel. We do not read this to remove the 690.9(A)(1) exemption for the solar PV circuit.

The overcurrent devices in (other than generator systems) shall be sized to carry not less than 125 percent of the maximum currents as calculated in 705.28(A).

Here that means the main breaker of the back up load panel will be  
 $40 * 1.25 = 50 \text{ amps.}$

### **Section 706 on energy storage systems (ESS)**

#### 706.30

We will apply this section to the circuit connecting the inverter to the battery. As relevant 690 sections are not about systems that inherently have batteries, and relevant 705 sections apply as other sections 690 and 706 do not.

- (A) Note this section makes a distinction between circuit current and maximum circuit.
- (1) Circuit current shall be the rated current indicated on the ESS nameplate(s) or system listing. Where the ESS has separate input (charge) and output (discharge) circuits or ratings, these

shall be considered individually. Where the same terminals on the ESS are used for charging and discharging, the rated current shall be the greater of the two.

The following sections (2)-(5) are about inverters specifically so we interpret that this refers to the battery portion of the ESS. Its maximum charge/discharge currents are both 14.3 amps.

(2) Inverter output current (on the battery circuit) is the maximum of the inverter's continuous output current rating.

This is still actually 50 amps.

706.31

(A)ESS circuit conductors shall be protected in accordance with the requirements of Article 240. ESS circuit conductors shall be protected in accordance with the requirements of Article 240.

This means that the non grounded conductor of the battery will need overcurrent protection.

(B)Overcurrent protective devices, where required, shall be rated in accordance with Article 240 and the rating provided on systems serving the ESS and shall be not less than 125 percent of the maximum currents calculated in 706.30(A). So the battery circuit breaker needs to be based on 706.30(A)(2) and is  $50 * 1.25 = 62.5 \text{ amps}$ . We thus spec a 70 amp breaker.

Overcurrent protective devices, either fuses or circuit breakers, used in any dc portion of an ESS shall be listed for dc and shall have the appropriate voltage, current, and interrupting ratings for the application

**For the more generic branch circuit from the back up load panel to the AC unit, we review section 440 and 240.**

440.31 describes that for Hermetic Refrigerant Motor-Compressor equipment, ampacity of branch circuit conductors is determined by the rated-load current marked on the nameplate of the equipment and a 125% increase.

For this AC unit, its nameplate rating is 1187 w at 115v. We calculate a rated current of  $1187w / 115v = 10.3 \text{ a}$ . The conductor then should be specified to  $10.3 * 1.25 = 12.87 \text{ amps}$ . But because we will need a larger breaker and are worried

about voltage drop on this length of a branch circuit we will specify conductor capable of 20 amps.

440.12(A) describes the required interrupt rating of the disconnect for Hermetic Refrigerant Motor-Compressor equipment to be at least 115% the rated-load current. This results in  $10.3 * 1.15 = 11.845$  amps.

But we will use a breaker as this disconnect, that will also function as the overcurrent protection of the branch circuit. To protect the conductor as per 440.22 overcurrent protection needs to be not less than 175% of the rate-load current. This is  $10.3 * 1.75 = 18.025$  amps. We will then use a 20 amp breaker.

CEC 408.6 requires that panelboards have a short circuit current rating greater than the available fault current.

We will verify this for the PV subpanel and the backup panel later when we calculate fault currents. Additionally that fault current shall be marked on the enclosure at point of supply along with the date the calculation took place. We will do this for the back up panel we install.

CEC 408.30 requires that the panelboard's rating be larger than the minimum feeder capacity required for the load calculated in accordance with Part III, IV, or V of Article 220, as applicable.

This will be applicable to the PV and backup panels.

220.40 describes that the calculated load shall not be less than the sum of the loads on the branch circuits after applicable demand factors have been applied.

For the ac unit, that load (according to CEC 440.6(A)) is the rated load current marked on the nameplate, that was 10.3 amps. We locate a demand factor of 100% in 220.83 (B) for air conditioning units. But for farm loads in non-dwelling units you use a demand factor of 125% of the largest motor (according to table 220.102). This would give a rating of 12.875 amps and we round up to 13 amps. The panelboard must be rated above this amount of current (it most surely will be).

For the PV sub panel, we see that there likewise only one circuit on the panel (although we may describe it as a feeder circuit as opposed to a branch circuit). But we understand the load on it to be equal to the rated current of the inverter input (as per CEC 706.30(A)(3)). The inverter calls this value out as 40 amps. The 220.102 table indicates that for all loads expected to operate simultaneously the demand factor is 100%. We will use that demand factor and decide that the PV sub panel (its bus) should be rated above 40 amps, which it is.

CEC 408.36 requires overcurrent protection for the supply side of panels.

The main breaker in the PV panel accomplishes this. But we understand that for the backup panel, it needs protection on its supply side. We see the only way to accomplish this is to use a panel that includes a main breaker. This means we will have to spec a physically large panel with way more breaker spaces than are required to serve a single backed up load. But the code mandates what it mandates and we cannot connect a breaker inside of the inverter.

### Backup Load

We will spec a panel with a main circuit breaker even though it serves only a single branch circuit. We recommend Siemens' SNW1224B1100, it has 120/240v voltage support, has twelve breaker slots and a 100 amp rated bus to allow for additional loads to be installed in the future, it is NEMA 3r outdoor use rated and it has a UL listed certification. We will put in a Siemens 2-pole 50 amp QPH breaker for its main breaker as per CEC 705.30. We will run both 120v output lines to the backup panel, there could be a 240v load connected there in the future.

This is a bummer of a solution to CEC 440.12. Perhaps the engineering company will have the expertise to spec a smaller main lug only panel and include a description of how to retrofit a main breaker into the smaller panel. We do not have this expertise.

The back up load is a single phase 115v air conditioner. To protect its branch circuit we will spec a breaker of 20 amp rating.

## Battery

The battery we include in the design qualifies as part of an energy storage system (ESS) under CEC 706.1. While it is intended to provide backup power at times it is not part of an uninterruptible power supply system (UPS system). It is also intended to provide electrical energy to the onsite wiring system so it is more than just a battery storing energy, it is part of an ESS. We interpret CEC 706.15 to mandate the same disconnect that we have been calling “the AC disconnect.” We interpret the definition of ESS to apply to the whole generation system. So that single AC disconnect should work and its markings should be sufficient. We will also have a breaker on the circuit from the battery to the inverter that can likewise act as a disconnect, being opened and a lock being attached closing the box enclosing it.

Finding DC breakers is much more difficult than finding AC ones. First of all, it is harder to prevent arcing in DC breakers, because there is no time that the voltage potential across the disconnecting breaker terminals = 0, (like there momentarily is in the AC case). Secondly, there is a wide variety of DC voltages that one would ostensibly have to protect, this makes zeroing in on one that is rated ~400v (but not rated in the kV range) difficult. We eventually find a two pole breaker rated to 500v DC with amperage ratings in the range we are looking for. Our understanding of breaker operation indicates that a two pole breaker will be able to safely protect a pole connection. A 2 pole breaker should operate to open the circuit if either of its poles experience current higher than it is rated for, so leaving one pole section open should not prevent the other from operating correctly. Additionally, we do not see anything in the NEC that would prevent a two pole breaker from working in a single pole application. We will spec a Chtaixi DC Miniature breaker of 70 amp rating as per CEC 706.31(B) While we could not find a UL certification for this device, it does have a IEC60947-2 standard for low voltage switchgear. Because our options seem so limited, we are inclined to accept this certification as sufficient, but have concern that listing requirement CEC 706.31(B) may not be satisfied.

As far as finding an enclosure, this is also difficult. We understand the mounting method of the DC breaker, DIN, to be commonly used in Europe, so finding a box with both DIN support and NEMA outdoor enclosure rating is not easy (we understand that we need a NEMA 3R rated enclosure to protect equipment from ice and personnel from hazards). We eventually decided that using Polycase's ZH-060604 hinged junction box with accessory cable glands to get wires in/out and an installable DIN bar is our best bet to enclose a double pole DC breaker. The

roughly 7"x7"x5.7" size should be large enough to house both the breaker and the DIN bar in accordance with CEC 312.8 (A). The enclosure has the appropriate NEMA protection. There should not need to be electrical connection to anything but the DC breaker itself.

The difficulty we have finding components of this nature lead us to believe that we make some kind of mistake. We perhaps do not need a DC breaker for a battery of this size? All the DC breakers from brands that we recognize are rated for either much higher current, much higher voltage, or 3 or 4 poles. Perhaps we need a different kind of device, using a disconnect switch does not seem to provide automatic operation. Using fuses seems unrealistically difficult on the operator. How would they safely isolate the batteries when they want to? The inverter DC switch only seems to isolate the entire DC side. Additionally, it seems onerous to expect City Farms to keep a bunch of spare fuses around and safely install them every time something causes them to burn out. We do not believe that there should be a whole separate battery management system of similar cost to the smart inverter. The smart inverter is capable of deciding operation mode and managing power flow, we simply worry about fault protection. At the end of the day we find our solution acceptable based on our current understanding, but expect that understanding to be somehow deficient. Thus while we list components for the DC battery breaker and enclosure, we will not go to the extent of creating a detail on how the enclosure will have the cable glands installed and detailing the dimensioning of the breaker fitting inside the enclosure. We find it plausible for the professional company to discard these parts and use something of a standard manufacture and installation method, even if we cannot identify what that should be.

We will locate the battery breaker/enclosure on the solar panel support structure adjacent to the battery. We find this acceptable under CEC 240.21 (H) and will be in an accessible latched enclosure satisfying CEC 240.24 (A). As per CEC 480.7 (F) the breaker will be marked with nominal battery voltage, available fault current derived from the stationary battery system, an arc flash label in accordance with acceptable industry practice, and the date the calculation was performed.

As an aside, the micro-grid system will be able to charge from the grid and thus represent a load. This micro-grid load must not push the entire site load to above what the service transformer can support. To ensure this is not the case, we will ensure the micro grid cannot draw more than 25kVA ever, and also plan on only allowing the micro-grid batteries to charge between times 12:30 am and 3:30, when the site's loads are small. We can see that in all of the

graphs presented in the PG&E data section, the demand at these times is almost always low to non-existent. Setting a charging time of this nature should be easy to accomplish in the inverter settings.

### Inverter/PV

We are confident that the existing subpanel feeding the existing inverter was UL and outdoor use rated, or it would not have been installed. We are confident that the 100 amp main breaker located in the PV subpanel is sized correctly to protect from fault currents and is likewise certified on the correct lists, or it would not have been installed. That rating is above the 40 amp requirement that we calculate pursuant to CEC 408.30

To replace the existing circuit breaker, we specify a 50 amp double pole breaker as per CEC 690.9(B). This is also called out as the correct breaker size in the GoodWe inverter manual [97].

We do want to consider that the backup load is also fed through the PV sub panel circuit breaker as we size . When the inverter is working normally, the backed up load will be fed from the inverter's internally controlled circuitry, but the inverter's power will not go above its rated AC input current. It could mean that the battery cannot charge with all 9.6 kw, this is fine. But in the case that the AC bypass switch is activated when the inverter is not working and the back up load is fed through non-controlled circuitry the only draw through the PV breaker will be the backup load power. This will also be fine.

### **Conduit and Wiring**

We will start by declaring that we will use copper THWN unless otherwise specified. Once we decide on ampacity rating in the following sections we will use table 310.16 to chose a size. This table is appropriate because our conductors will be in cable conduit and then buried and there will not be more than 3 current carrying conductors, 2 hot conductors 120v from the neutral and 180 degrees out of phase with each other, and the neutral. As the conductors (except the solar PV DC conductor) will be buried, we do not need to consider ambient temperatures higher than the standard 30 degree celsius that table 310.16 (3) assumes.

CEC 690.8(B)

Circuit conductors shall be sized to carry the ampacity calculated by 690.8(A) multiplied by 125%.

For the PV DC circuit that was  $34.5 * 1.25 = 43.125$  amps. We find this calculation unlikely as this seems to imply that each of the conductors to each separate string must be rated to carry the current available from all three strings. We feel this must be a mistake in our interpretation, in 690.8(A)(1)(a) a circuit could refer to each string as no string conductors are connected in parallel as they enter the inverter. In that case the conduit would be sized to  $9.28 * 1.25 * 1.25 = 14.5$  amps. Because the ambient temperature in San Luis Obispo has reached up to 106 degrees fahrenheit, and THWN wire has a conductor temperature rating of 75 degrees celsius, we need to use table 310.15(B) to multiply the ampacities in table 310.16 by .82 to get their temperature adjusted rating. Specifying 14 AWG Copper has a modified amperage rating of  $20 * .82 = 16.4$ . This would still be acceptable, except that the protection on the inverter is rated for 15.2 amps. According to 240.4 (D)(3), the largest protection allowed on 14 AWG Copper is 15 amps. Therefore we upsize the conductor to be 12 AWG copper. For the inverter circuit to the service that was  $40 * 1.25 = 50$  amps. This calls for 8 AWG copper. This applies to all the conductor between the inverter and the PV sub-panel that we will be installing new.

#### 705.28

(B) We interpret that (like other applications) the ampacity of the conductor (from the inverter to the back up load panel) shall be 125% of the maximum current calculated in the calculation part of the same section (705.28(A)).

In this case that is  $40 * 1.25 = 50$  amps. This calls for 8 AWG copper.

(C) The neutral conductor (there will be one on the circuit from inverter to back up panel) will be the same size as the ampacity calculated in 705.28(B) or 50 amps. This calls for 8 AWG copper.

The conductor from the back up load panel to the air conditioning load was specified to 20 amps. This calls for 14 AWG copper.

#### 706.30(B)

(B) The conductor ampacity of circuits servicing the ESS loads (the battery) shall be sized to the larger of either the value from 706.30(A)(1) or based on the overcurrent protection on the circuit (we understand to be calculated in 706.31(B)).

So we use the 70 amp rating of the breaker calculated in 706.31(B) and will size the conductor to 70 amps. This calls for 4 AWG copper.

(C)Neutral conductor

This is an important consideration, but we understand that the battery circuit will not have a neutral conductor. Because CEC 690 is silent on neutral conductors (it speaks on PV DC circuits without neutral conductors) we will use this to size the neutral conductor on the circuit from the inverter output to the service. It must be sized to the maximum unbalanced neutral load current plus the ESS(s) output rating. The inverter should be balanced across its two 120v input lines so there should be no unbalanced neutral load current. Then the conductor should be sized to the inverter's output rating (to the grid) of 40 amps. This calls for 8 AWG copper.

We specified the conductor size from the back up panel to the back up load above.

We understand the CEC does not consider voltage drop on conductors to be a safety issue and does not have requirements for it. Instead they recommend via informational notes that there be up to a 5% drop on the lines we design/install between the service and each load (there can be a <3% drop in a feeder and an additional <3% drop in individual branch circuits). We will check this in the "Voltage Drop Calculation" section and upsize our conductors as necessary.

## Grounding

We understand that grounding requirements for the facility will come primarily from CEC 690, as it references CEC 250. But there are some additional general grounding provisions.

As per 408.40 metal panel boards must be grounded.

We will assume that the PV sub panel is already grounded appropriately. We plan on directly connecting (via conductive metal) the other panels to the PV panel mounting structure, this structure will be grounded.

As mentioned before, the PV DC circuit is intended to operate ungrounded according to the inverter manual. This is acceptable under CEC 690.41 (A)(4).

250.52(5) calls for a grounding electrode of the same length found at the current generating facility.

We will assume the existing electrode already meets other listing/coating requirements.

The connection between the grounding electrode the metal PV support structure bonded appropriately, or it would not have passed installation inspection.

690.41 Requires ground fault detection and faulted current control.

We understand that the inverters' PV insulation resistance protection is a form of ground fault protection [79] and reference it along with the visibility of the PV DC disconnect switch to justify that these requirements are met. This also satisfies 690.42, in that the current carrying conductor's (of the PV circuit) connection to ground is made by the ground fault protection device.

690.43

(B) Equipment secured to grounded metal supports, as much of our equipment will be, is allowed to bond to the support with listed and labeled bonding equipment.

As we reference the original metal PV support structure is grounded, so to ground our new equipment we need to bond it to the metal support it is on and additionally connect all the metal support structures together with equipment grounding conductor.

(C) That grounding conductor will be contained in the same cable as the other PV system conductors.

690.45

The size of the grounding conductor will be calculated from CEC 250.122.

The largest overcurrent protection device on the circuit bonded to the metal support structure is the 60 amps so we read the table to require 10 AWG copper THWN wire. But again we compensate for ambient temperature because the conductor will be in the air, using the same .82 factor 8 AWG copper will then support 82 amps (while 10 AWG only supports 49.2 amps). So we will size to 8 AWG copper.

## **Markings**

The existing markings at the site were permitted and found sufficient. We do not understand the nature of the new site to differ all that significantly. In our site plan we will attach images of new markings that we have so far articulated that we will need on the site but beyond that we will not change or add additional markings. Those newly articulated warning markings are: update the site plan warning sign to show new panel locations and disconnects, add voltage and available fault current calcs, with arch flash labels to both the AC disconnect and the battery breaker. See site plans for specific language.

## One-Line Diagram and Conductor Table

This diagram in Figure 45 indicates all the connections between equipment, the sizes of breakers, switches, fuses, panels, inverter and battery. It indicates possible fault locations. Table 12 indicates the corresponding conductor sizes and their lengths.

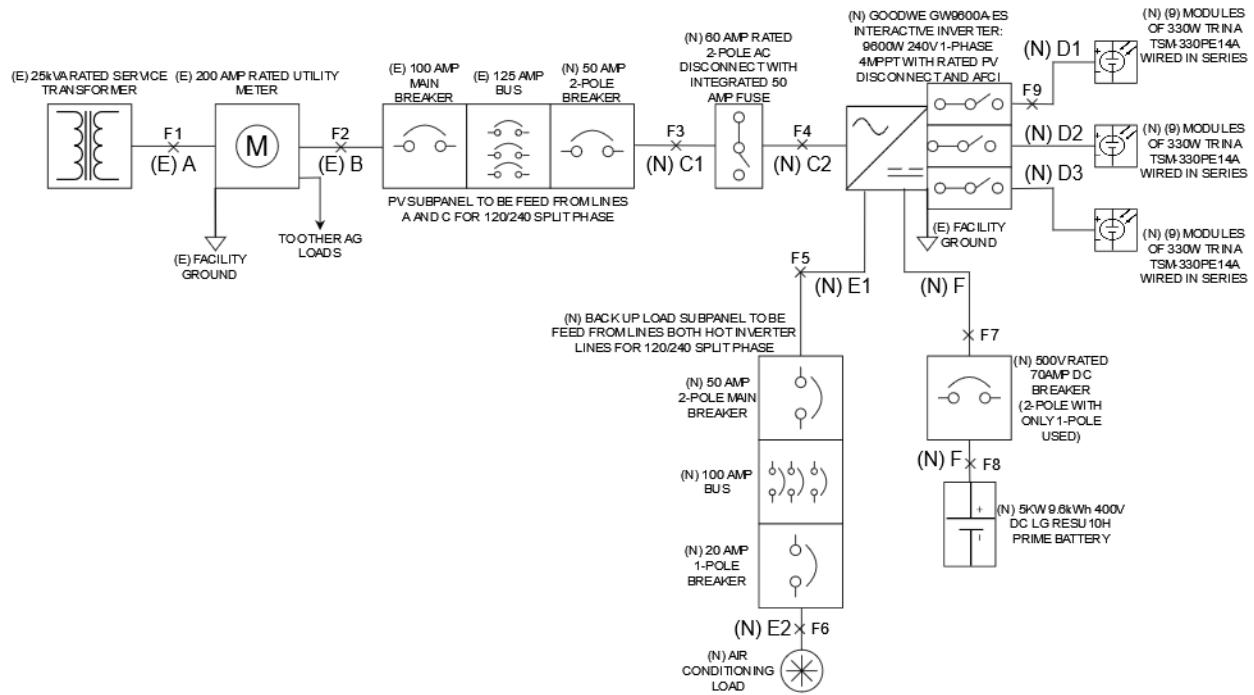


Figure 45. Single Line Diagram For Our Design

Conductor Table (Without voltage drop adjustment)				
Line	Conductor	Neutral	Ground	Length
A (existing)	Unknown type	Unknown	Unknown	70'
B (existing)	(2) #1/0 THWN	#1/0 THWN	#4 THWN	35'
C1 (new)	(2) #8 THWN	#8 THWN	NA	90'
C2 (new)	(2) #8 THWN	#8 THWN	#8 THWN	10'
D 1-3 (new)	(2) #12 PV	NA	#8 THWN	15', 45', 55'
E1 (new)	(2) #8 THWN	#8 THWN	#8 THWN	10'
E2 (new)	#14 THWN	#14 THWN	#8 THWN	65'
F (new)	(2) #4 THWN	NA	#8 THWN	15'

Table 12. Conductor Wire Sizes and Lengths

## Simulation and Results

### Voltage drop calculations

We mention that we want to keep voltage drops below 3% on both feeders and branch circuits individually and less than 5% overall. Meeting this standard will allow all of our equipment to function as intended at its proper efficiency.

To do this we need to calculate all the drops and increase conductor size as necessary. Different institutions have different tables and associated equations to use. We prefer the ones proposed by Mike Holt's website. He produces lots of information/teaching resources/seminars/videos to understand the NEC code and we trust his methods and understanding in this case. There are some more complicated equations for three phase conductors that take into account skin effect and power factor of the load being supplied, but for 1 phase (and thus split phase) conductors he recommends simply using ohm's law. The maximum load current on the current of the conductor (not the current the conductor is rated for or the breaker current), the conduit resistance per 1000 feet will be given by CEC Chapter 9 table 9 for alternating current conductors and Chapter 9 Table 8 for dc current conductor. We will understand that the conductor should be uncoated and stranded in the DC case and should be in PVC conduit in the

AC case. We also know that the inverter can alter its power factor to maintain near unity on the microgrid system so for AC we will assume near unity power factor.

$$voltage\ drop = VD = i * table\ conduit\ resistance \frac{1}{1000} (\frac{ohm}{ft}) * conduit\ length(ft)$$

$$percent\ voltage\ drop = \frac{voltage\ drop}{rated\ voltage} * 100$$

The voltage drop from the meter to the pv subpanel (conductor B) is

$$VD = 40\ amps * \frac{.12}{1000} * 35 = .168v$$

$$\%VD = .168/240 = .07\%$$

The voltage drop from pv subpanel to to AC disconnect (conductor C1) is

$$VD = 40\ amps * \frac{.78}{1000} * 90 = 2.81v$$

$$\%VD = 2.81/240 = 1.17\%$$

Voltage drop from AC disconnect to inverter (conductor C2) is

$$VD = 40\ amps * \frac{.78}{1000} * 10 = .31v$$

$$\%VD = .31/240 = .13\%$$

All these voltage drop percents  $.07 + 1.17 + .13 = 1.37\%$  which is less than 3%. So far so good.

The voltage drop from inverter to backup panel load (conduit E1) is

$$VD = 40\ amps * \frac{.78}{1000} * 10 = .31v$$

$$\%VD = .31/240 = .13\%$$

This .13% plus the 1.37% drop to the inverter equals 1.5% which is still less than the 3% max voltage drop on feeders.

The voltage drop from the back up panel to the to the AC load (conductor E2) is

$$VD = 10.3\ amps * \frac{3.1}{1000} * 65 = 2.07v$$

$$\%VD = 2.07/120 = 1.73\%$$

This 1.73% is the branch circuit voltage drop it is less than 3% and if summed with the 1.5% drop to the back up panel, the total is 3.23% which is less than 5%. So all of this conductor is fine.

The voltage drop from the inverter to the farthest solar panel (conductor D3) is

$$VD = 9.28 \text{ amps} * \frac{6.5}{1000} * 55 = 3.32v$$

$$\%VD = 3.32/336 = .99\%$$

This is actually probably not something we needed to calculate, the solar panels are creating the voltage. We suppose it is worth it to know that the inverter input is receiving a closer 333v not the nominal 336v.

The voltage drop to the battery is actually important because it is a load instead of just being a source. This is conductor F. We use the battery charge current instead of the rated inverter output current because the way we have the breaker set up, there cannot be another battery added that could suckup more current from the inverter.

$$VD = 14.3 \text{ amps} * \frac{1.01}{1000} * 15 = .216v$$

$$\%VD = .216/400 = .05\%$$

That added to the 1.37% voltage drop to the inverter is 1.42% which is less than the 5% maximum recommended voltage drop to loads.

## Available Fault Current Estimation

Because we did not pay PG&E the >\$800 for this information we will estimate available short circuit current using the procedure referenced by Benha University [65].

### Step 1) Determine full load amps of transformers

We understand the service transformer to be a 25kVA 240v 3-phase transformer. To determine the full load amps we use equation  $I_{FLA} = \frac{KVA*1000}{E_{L-L}*\sqrt{3}} = \frac{25*1000}{240*\sqrt{3}} = 60.14 \text{ amps}$

## Step 2 and 3) Determine Let Through Short Current by Either Equation or Table

To find via equation we need the % impedance of the transformer. We cannot check this on the transformer and have been unable to find a consistent standard value for it elsewhere. We do notice that on none of the transformers listed in Table 5 of the document is the % impedance less than 1. We find this a likely worst case scenario for our transformer and will proceed with the 1% impedance value.

This equals  $Multiplier = \frac{100}{TXRF \%Z} = \frac{100}{1} = 100$

Then short circuit current is calculated  $I_{SCA} = I_{FLA} * Multiplier = 60.14 * 100 = 6014 \text{ amps}$

This is roughly what we expect the available short circuit current from the secondary of the transformer to be. It is our disposition to want to increase this estimate because our numbers are so uncertain. We notice that other 3-phase transformers under 100kVA put out around 300 amps per kVA, if our transformer did as well that would be  $300 * 25 = 7500 \text{ amps}$ . This is not much higher than the value we calculate with our guessed % impedance but in this situation we believe it pays to overestimate and we will go with the higher number.

The inverter should be able to contribute about ~60 amps to the fault current up-stream of it, which does not significantly change anything. [82]

## Bussman SC Calcs

The actual short circuit current that would flow into the system depends on where in the system a fault is located and what kind of fault it is. If a bolted 3 phase fault (the worst kind) were to occur right in front of the meter, fault location F1 in our single line diagram we would calculate an "f" factor

$$f = \frac{1.732 * L * I_{L-L-L}}{C * n * E_{L-L}}$$

where L = length (feet) of conduit to the fault. Here it is the 70' from the service to the meter.

C = conductor constant. See Tables 1, 2. Here it is 3826 for three single conductors of (the assumed) #4 wire in non-magnetic conduit

n = number of conductors per phase. Here we assume that to be 1

I = available short-circuit current in amperes at beginning of circuit. Here that was the 7500 amps.

E= the line voltage. Here is 240v

$$\text{So } f = \frac{1.732 * 70 * 7500}{3826 * 1 * 240} = .990$$

Then the fault current caused by 3 phase fault at that location would be

$I_{F1} = I_{\text{passed}} * \frac{1}{1+f}$  where  $I_{\text{passed}}$  is the current calculated in the previous location, here it is the fault current available from the transformer

$$I_{F1} = 7500 * \frac{1}{1+.99} = 3768 \text{ amps}$$

Hopefully the main breaker (if it is at the meter) is capable of interrupting that kind of current (surely it would be, as someone had to verify this using the actual fault current available from the transformer before that main breaker was installed).

Continuing to a fault at F2, immediately before the pv sub-panel. Now that this is a one phase line we understand from the procedure that we should go back and calculate the line to line fault current available immediately before the meter and then use that current to calculate the F2 current.

The 1-phase line-line current calculation for "f" factor is similar but not the same.

$$f = \frac{2*L*I_{L-L}}{C*n*E_{L-L}}$$

$$\text{So line-line fault at fault location F1: } f = \frac{2*70*7500}{3826*1*240} = 1.14 \text{ and}$$

$$I_{F1} = 7500 * \frac{1}{1+1.14} = 3504 \text{ amps}$$

$$\text{So then the fault location F2 single phase fault current: } f = \frac{2*35*3504}{9317*1*240} = .109 \text{ and}$$

$$I_{F2} = 3504 * \frac{1}{1+.109} = 3159 \text{ amps}$$

$$\text{Then F3: } f = \frac{2*90*3159}{1559*1*240} = 1.52 \text{ and } I_{F2} = 3159 * \frac{1}{1+1.52} = 1253 \text{ amps}$$

$$\text{Then F4: } f = \frac{2*10*1253}{1559*1*240} = .067 \text{ and } I_{F2} = 1253 * \frac{1}{1+.067} = 1174 \text{ amps}$$

We are confident all the equipment we specify will be able to interrupt this magnitude of current. All the breakers we saw have a minimum short circuit rating of ~10kA if not greater than that. The main circuit breaker tripping current is unknown to us, but it surely is not larger than 1174 amps. So in the case of a fault it should trip.

Faults that occur further down (at F5-9) should be isolated by the inverter's short circuit protection.

We will consider the fault current available from the inverter, battery and solar panels. The solar panels can contribute roughly 10 amps per string for a fault at any of their lines (F9), all of which the inverter's short circuit protection should be able to handle and disconnect. The battery actually has a short circuit current of 1.106 kA. [83] This is significant but will not fry the battery breaker (which has a A.I.C rating of 4kA). A fault at F8 will trip the battery's internal short circuit protection. The backup breakers will surely be able to disconnect the inverter short circuit current it can output which is between 40 and 60 amps. For a fault at F5, we expect the inverter's own short circuit protection to operate.

## Arc-Flash

Given how small our voltages are and our fault currents were calculated to be, arch-flash does not appear to be all that significant of a safety concern. We therefore will perform arc-flash calculations only at the nodes where we are required to include arc flash warning signs.

At the AC disconnect, significant fault current (more than the fault 60 amps from the inverter) would only flow through it if there were to be a fault at F4. The boundary distance of the arc can be ballaparked by using the rating of the service transformer and the time before the fault is cleared. [84]

The equation looks as follows  $D = \sqrt{53 * 1.25 * Rating * time}$

The rating of the service transformer is 25kVA (the equation expects MVA and has a 1.25 multiplication factor if the rating is small. The approximate clearing time for a fuse (the protection that would clear the fault first) is .004 seconds.

The distance calculated in feet is  $\sqrt{53 * 1.25 * .025 * .004} = .0814 \text{ feet} = .976 \text{ inches}$

We do a similar calculation at this fault location and get a similar number using the more specific method we are about to describe below.

For the fault at the battery, we need to use the fault current and voltage at the battery to calculate the power in the arc. According to the battery, the circuit voltage it sustains is 171.4 v, and its fault current is 1.106 kVA. [83] The power of this DC fault would be

$$171.4 * 1106 = .1896 \text{ MVA}$$

Then the clearing time of the fault (given by battery documentation is 792 us) must be taken into account to calculate the boundary distance

$$D = \sqrt{2.65 * \text{MVA} * t} = \sqrt{2.65 * .1896 * 792 * 10^{-6}} = .0199 \text{ feet} = .239 \text{ inches}$$

We now will calculate incident energy, the energy available from the arc at standard working distances (here 1 <600 V situation would be 18").

The battery manufacturer gives us the incident energy as .000088 Cal/cm<sup>2</sup>. [83] So we will forgo a mathematical calculation.

The fault at F4 can be calculated as follows [84]. Where d is the standard working distance in inches, t is the fault time, I is the fault current in kA (it was 1.174 kA here).

$$E = 5271 * d^{-1.959} * t * (.0016 * I^2 - .0076 * I + .8938) = .06498 \text{ Cal/cm}^2$$

None of these energies seem large enough to imply that our system is unsafe or that users of the system would have to take precautions outside of general electrical safety common sense.

# Conclusion

## Theoretical Bill of Materials

One unit of each of the following

DESCRIPTION AND PRODUCT NAME/MODEL NUMBER	MANUFACTURE	CURRENT RATING (A)	VOLTAGE RATING (V <sub>AC</sub> )	SPACES/POLE NUMBER	NEMA RATING/CERTIFICATION LISTING	WARRANTY	COST
AC DISCONNECT: DG222NRB	EATON	60	240	2-POLE 3-WIRE	3R	1 YEAR FROM INSTALL	\$146
CLASS H FUSE: RF50	FERRAZ	50	250	NA	UL	NA	\$20
BACKED UP LOAD PANEL: SNW1224B1100	SIEMENS	100	240	12-SPACE	3R	1 YEAR	\$139
BACKED UP LOAD PANEL MAIN BREAKER: 50 AMP QP	SIEMENS	50	240	2-POLE	UL	NA	\$19
BACKED UP LOAD BREAKER:	SIEMENS	20	240	1-POLE	UL	NA	\$8
PV SUBPANEL LOAD BREAKER: 50 TYPE QP	SIEMENS	50	240	2-POLE	UL	NA	\$19
BATTERY BREAKER: CHTAIXI DC MINIATURE BREAKER	CHTAIXI	50	500V <sub>DC</sub>	2-POLE	IEC60947-2	NA	\$15
BATTERY BREAKER ENCLOSURE WITH ACCESSORIES: ZH-06-604	POLYCASE	NA	NA	>1-SPACE	1, 2, 3, 3R, 3X, 3RX, 3S, 3SX, 4, 4X, 5, 12, 13	NA	\$120

Table 13. Smaller Electrical Equipment Bill of Materials

DESCRIPTION/ MODEL NUMBER	MANUFACTURER	QUANTITY	CERTIFICATION	WARRANTY	COST
HYBRID INVERTER: GW9600A-ES	GOODWE	1	UL 1741 SB,  NEMA 4X ETCETERA	10 YEARS	\$4305
SOLAR PANELS: TSM-330PE14A	TRINA	15	UL 1703 ETCETERA	25 YEARS	\$1114
BATTERY: RESU 10H PRIME	LG ENERGY SOLUTIONS	1	UL 1642  UL1973  OUTDOOR IP55 ETCETERA	10 YEARS	\$6308

Table 14. Larger Electrical Equipment Bill of Materials

Electrical Equipment Total = \$12,193

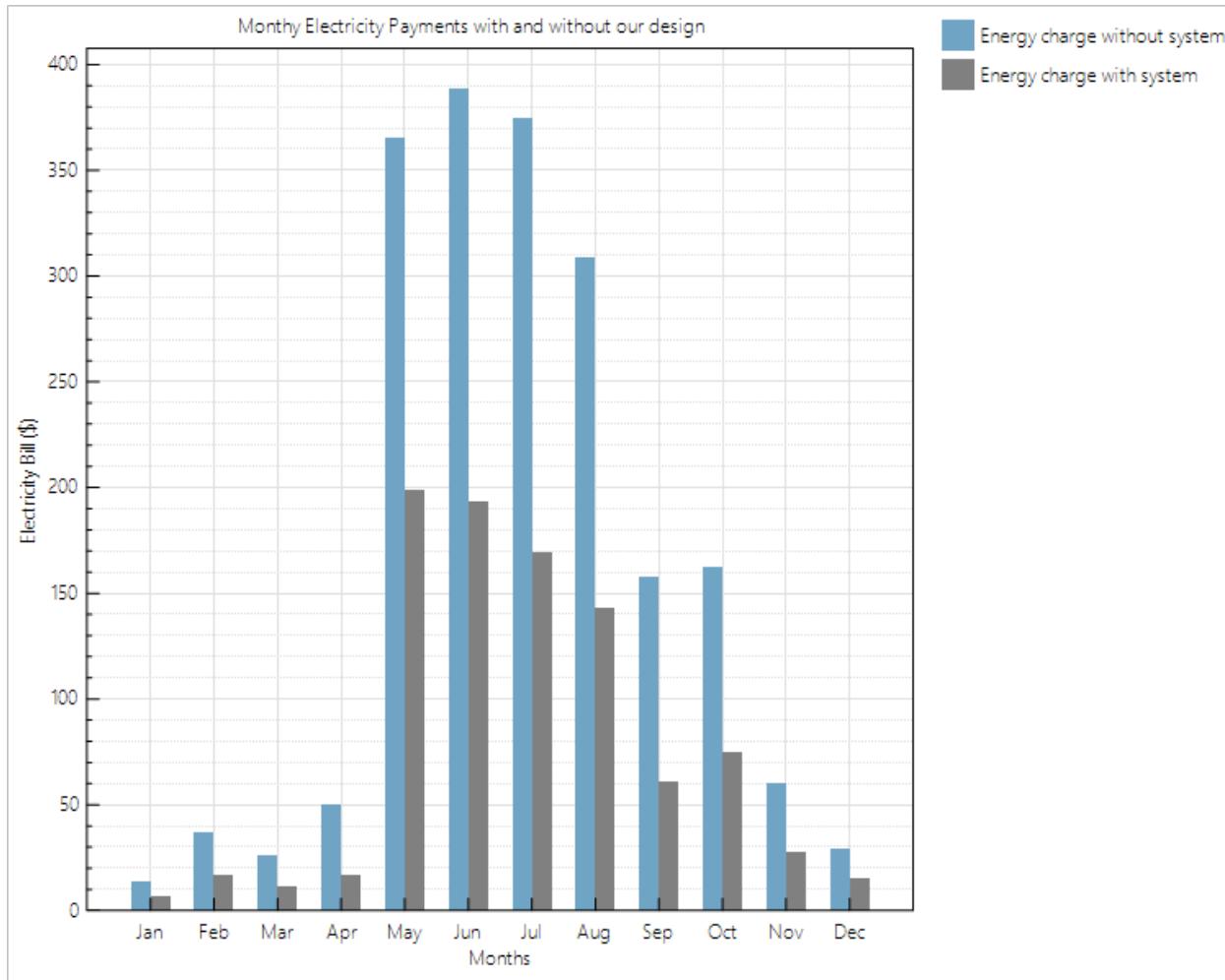
In addition to this accounting, the installation will also have costs from the purchase of conduit/conductors, installation costs, and PG&E costs.

## Expected Lifetimes and Warranty Accounting

All of our specified equipment that costs more than \$150 will have the full 10 year warranty called for by PG&E's NBT Schedule Special Condition 3. Any ongoing agreement to inspect and service equipment should be able to be done with cost to City Farm. Things like panelboards may be a headache to replace in terms of having to shut the system down for days while a replacement arrives but nothing should be financially costly to replace and the failure of any component should not damage any other component (if we truly designed the protection system correctly).

## Simple Financial Analysis

The City Farms has a TOU rate schedule categorized as AG-A1, as per their billing history. This is the default rate for agricultural consumers (and nonprofit agricultural entities) with <35kW of demand and "low" use. [27]



**Figure 46.**

The net savings with the system, year 1, would be \$1,038. It has an LCOE of 11.21¢/kWh. The microgrid would cost \$48,011.

<b>Direct Capital Costs</b>						
Module	1 units	10.0 kWdc/unit	10.0 kWdc	0.56 \$/Wdc	▼	\$ 5,600.00
Inverter	1 units	8.7 kWac/unit	8.7 kWac	0.46 \$/Wdc	▼	\$ 4,600.00
			\$	\$/Wdc		\$/m <sup>2</sup>
Balance of system equipment		0.00	0.99	0.00		\$ 9,900.00
Installation labor		0.00	+ 0.17	+ 0.00	=	\$ 1,700.00
Installer margin and overhead		0.00	0.99	0.00		\$ 9,900.00
Battery DC capacity	5.7 kWh	× 273.52 \$/kWh	+ 1.5 kW	× 545.48 \$/kW	=	\$ 2,405.28
					Subtotal	\$ 34,105.28
<b>Contingency</b>						
		Contingency	0 % of subtotal			\$ 0.00
					Total direct cost	\$ 34,105.28
<b>Indirect Capital Costs</b>						
		% of direct cost	\$/Wdc		\$	
Permitting and environmental studies		0	0.24	0.00		\$ 2,400.00
Engineering and developer overhead		0 +	0.98	+ 0.00	=	\$ 9,800.00
Grid interconnection		0	0.00	0.00		\$ 0.00
<b>-Land Costs</b>						
Land area	0.069 acres					
Land purchase	\$ 0/acre	+ 0	+ 0.00	+ 0.00	=	\$ 0.00
Land prep. & transmission	\$ 0/acre	+ 0	+ 0.00	+ 0.00	=	\$ 0.00
					Total indirect cost	\$ 12,200.00
						=
Percent of indirect cost attributed to battery	20 %				Total battery indirect cost	\$ 2,440.00
						+
					Total system indirect cost	\$ 9,760.00
<b>Sales Tax</b>						
Sales tax basis, percent of direct cost	100 %					
Sales tax rate	5.0 %					
						\$ 1,705.26
<b>Total Installed Cost</b>						
					Total battery related installed cost	\$ 4,965.54
					Total system related installed cost	\$ 43,045.00
					Total installed cost	\$ 48,010.54
The total installed cost is the sum of the indirect, sales tax, and direct costs. Note that it does not include any financing costs from the Financial Parameters page.					Total installed cost per capacity	\$ 4.80/Wdc

Figure 47.

## Articulate what goals were[n't] met

According to our own calculations and understandings, the protection system on the design will clear all faults safely and will support all the loads connected to it at sufficient voltage and

power. If our assumptions about the existing system are correct (and we have gone to pains to explain why we make the assumptions we do) then the design should be approvable by PG&E without detailed review or extensive validation of equipment.

Surely our interpretation of the CEC and PG&E requirements is deficient at times. We are code neophytes and were unable to get our interpretations quality controlled by professionals. We expect the professional company to change aspects of the design, particularly the protection system, because of this. But hopefully we expect to still offset a significant proportion of their work.

We are regretful that we were not able to work loads into our design to serve the tenants at the back of the farm. City Farm wanted this as one tenant in particular is dealing with a haphazard electrical system as he tries to charge//utilize electrical equipment. We did not feel comfortable drawing our system connecting to loads/panels we had little information about. But we expect that the professional engineering company will have the requisite information, and that it should be simple for them to spec a breaker in the existing load panel then run conductor to the structure where the tenant wants power.

Back up load goals

Financial feasibility goals

## **Recommendations for Future Work**

We do not see any particular work to be done apart from what the professional company is going to do. This is a significant amount of work. We expect them to slightly alter the electrical design we propose, but do not expect them to have to do much leg work in that respect. All the equipment we spec should be easy to purchase, with low lead times. They have to pull all previous permits from the city, buy reports from PG&E, do various formal meetings with City Farms and the company that designs the new City Farm Barn, polish and finalize the electrical and mechanical designs, go through the permitting process with both PG&E and the AHJ, build the facility, and perform regular inspections and maintenance. It is this writers opinion that perhaps the financial analysis could be taken further and perhaps if necessary some costs could be reduced.

## References

- [1] "Rural Energy for America Program Renewable Energy Systems & Energy Efficiency Improvement Guaranteed Loans & Grants." Rural Development, 31 Aug. 2022, <https://www.rd.usda.gov/programs-services/energy-programs/rural-energy-america-program-renewable-energy-systems-energy-efficiency-improvement-guaranteed-loans>.
- [2] Arash Farokhi Soofi, Saeed D. Manshadi, Araceli Saucedo, Farm electrification: A road-map to decarbonize the agriculture sector, The Electricity Journal, Volume 35, Issue 2, 2022, 107076, ISSN 1040-6190,  
<https://doi.org/10.1016/j.tej.2022.107076>  
[Farm electrification: A road-map to decarbonize the agriculture sector - ScienceDirect](#)
- [3] Planeteria. (2022, July 25). *3CE dedicates additional \$400,000 in incentives to electrify local agricultural equipment* - 3CE. Central Coast Community Energy. Retrieved November 8, 2022, from  
<https://3cenergy.org/3ce-dedicates-additional-400000-in-incentives-to-electrify-local-agricultural-equipment/>
- [4] H. Li, Y. Yuan, L. Zhang and T. Huang, "Research and Application on Microgrid Integrated Energy Service Technology for Modern Agriculture," 2018 2nd IEEE Conference on Energy Internet and Energy System Integration (EI2), 2018, pp. 1-4, doi: 10.1109/EI2.2018.8582443.  
[Research and Application on Microgrid Integrated Energy Service Technology for Modern Agriculture | IEEE Conference Publication](#)
- [5] M. Belouda, Y. Jouini and A. Mami, "Optimal configurations of a photovoltaic-diesel electrical production system with electrochemical and inertial storage for an isolated agricultural site electrification," 2022 5th International Conference on Advanced Systems and Emergent Technologies (IC\_ASET), 2022, pp. 73-78, doi: 10.1109/IC\_ASET53395.2022.9765929.  
<https://ieeexplore.ieee.org/document/9765929>
- [6] "Agriculture." Gridscape, <https://grid-scape.com/industries/agriculture/>.  
[Agriculture – Gridscape](#)

[7]S. Hasan et al., "Centralized Microgrid: Agricultural Load in Rural Areas of Bangladesh," 2021 International Conference on Computational Performance Evaluation (ComPE), 2021, pp. 939-943, doi: 10.1109/ComPE53109.2021.9752129. [Centralized Microgrid: Agricultural Load in Rural Areas of Bangladesh | IEEE Conference Publication](#)

[8]R. V. Karunakaran, R. Ravikumar, K. Lakshmanan, M. Suresh and V. Vijayaraghavan, "Irrigation Load Optimization for Enhanced Agricultural Productivity in Rural Microgrid Clusters," 2020 IEEE Global Humanitarian Technology Conference (GHTC), 2020, pp. 1-7, doi: 10.1109/GHTC46280.2020.9342922. [Irrigation Load Optimization for Enhanced Agricultural Productivity in Rural Microgrid Clusters | IEEE Conference Publication](#)

[9]M. Singh and P. Balachandra, "Microhybrid Electricity System for Energy Access, Livelihoods, and Empowerment," in Proceedings of the IEEE, vol. 107, no. 9, pp. 1995-2007, Sept. 2019, doi: 10.1109/JPROC.2019.2910834. [Microhybrid Electricity System for Energy Access, Livelihoods, and Empowerment | IEEE Journals & Magazine](#)

[10]Abhishek Jaiswal, Lithium-ion battery based renewable energy solution for off-grid electricity: A techno-economic analysis, Renewable and Sustainable Energy Reviews, Volume 72, 2017, Pages 922-934, ISSN 1364-0321, <https://doi.org/10.1016/j.rser.2017.01.049>

[11]H. Renmu, Ma Jin and D. J. Hill, "Composite load modeling via measurement approach," in IEEE Transactions on Power Systems, vol. 21, no. 2, pp. 663-672, May 2006, doi: 10.1109/TPWRS.2006.873130 [Composite load modeling via measurement approach | IEEE Journals & Magazine](#)

[12]D. Kosterev et al., "Load modeling in power system studies: WECC progress update," 2008 IEEE Power and Energy Society General Meeting - Conversion and Delivery of Electrical Energy in the 21st Century, 2008, pp. 1-8, doi: 10.1109/PES.2008.4596557 [Load modeling in power system studies: WECC progress update | IEEE Conference Publication](#)

[13]H. Shahinzadeh, M. Moazzami, S. H. Fathi and G. B. Gharehpetian, "Optimal sizing and energy management of a grid-connected microgrid using HOMER software," 2016 Smart Grids Conference (SGC), 2016, pp. 1-6, doi: 10.1109/SGC.2016.7882945 [Optimal sizing and energy](#)

[management of a grid-connected microgrid using HOMER software | IEEE Conference Publication](#)

[14] Tamer Khatib, Azah Mohamed, K. Sopian, A review of photovoltaic systems size optimization techniques, Renewable and Sustainable Energy Reviews, Volume 22, 2013, Pages 454-465, ISSN 1364-0321, <https://doi.org/10.1016/j.rser.2013.02.023>

[15] N. Zhang, Y. Sun, D. Liu, Z. Li, C. -Y. Li and G. -L. Hu, "FL-TN:A fault location algorithm based on tree topology for smart grid," 2019 Chinese Control And Decision Conference (CCDC), 2019, pp. 6221-6225, doi: 10.1109/CCDC.2019.8833415.

[16] Nagarjun Y., "Effectiveness of On-grid and Off-grid rural electrification approaches in India," 2015 International Conference on Sustainable Energy Engineering and Application (ICSEEA), 2015, pp. 65-70, doi: 10.1109/ICSEEA.2015.7380747.

<https://ieeexplore.ieee.org/document/7380747>

[17]"Solar Industry Research Data." SEIA, <https://www.seia.org/solar-industry-research-data>  
[Solar Industry Research Data | SEIA](#)

[18]S. Amara, S. Toumi and C. B. Salah, "Sizing Study of an off-grid Wind-Battery Microgrid System," 2021 12th International Renewable Energy Congress (IREC), 2021, pp. 1-6, doi: 10.1109/IREC52758.2021.9624752.

[19] M. Morad, M. Nayel, A. A. Elbaset and A. I. A. Galal, "Sizing and Analysis of Grid-Connected Microgrid System for Assiut University Using HOMER Software," 2018 Twentieth International Middle East Power Systems Conference (MEPCON), 2018, pp. 694-699, doi: 10.1109/MEPCON.2018.8635166.

[20] H. A. Shayanfar and S. Malek, "Photovoltaic microgrids control by the cooperative control of multi-agent systems," 2015 30th International Power System Conference (PSC), 2015, pp. 287-293, doi: 10.1109/IPSC.2015.7827761.

[21] J. Zhang, A. Hasandka, S. M. S. Alam, T. Elgindy, A. R. Florita and B. -M. Hodge, "Analysis of Hybrid Smart Grid Communication Network Designs for Distributed Energy Resources

Coordination," 2019 IEEE Power & Energy Society Innovative Smart Grid Technologies Conference (ISGT), 2019, pp. 1-5, doi: 10.1109/ISGT.2019.8791581.

[22] P. Kos, R. Billinton and G. Wacker, "Cost of electric power interruptions in the agricultural sector-statistical analysis," in IEEE Transactions on Power Systems, vol. 6, no. 4, pp. 1432-1438, Nov. 1991, doi: 10.1109/59.116986.

[23] A. Broadbent, "Cross industry research supporting the future of electrification," IET Seminar on Railway Electrification: Lessons for the Future, 2013, pp. 1-40, doi: 10.1049/ic.2013.0169.

[24] Q. Wang, H. Su, Y. Chen, X. Chen and W. Xu, "Fault Location Algorithm for Power Grid Based on Protection Status Information and Aggregation Hierarchical Clustering," 2020 4th International Conference on Smart Grid and Smart Cities (ICSGSC), 2020, pp. 83-87, doi: 10.1109/ICSGSC50906.2020.9248567.

[25] Support Center, "Four Wire Delta Circuits," Continental Control Systems, LLC A Socomec Group, Longmont CO. [https://ctlsys.com/support/four\\_wire\\_delta\\_circuits](https://ctlsys.com/support/four_wire_delta_circuits)

[26] Connor Morinini, "City Farm SLO – Walk-In Produce Coolbot Cooler," California Polytechnic State University San Luis Obispo, San Luis Obispo CA, Spring Quarter Senior Project Group, pp 1-10, 2021.

<https://digitalcommons.calpoly.edu/cgi/viewcontent.cgi?article=1543&context=cmsp>

[27] *ELECTRIC SCHEDULE AG TIME-OF-USE AGRICULTURAL POWER*, CPUC No 48519-E, PG&E Tariffs/Advice Decisions, Robert Kenney, San Francisco, February 2021.  
[https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC\\_SCHEDULES\\_AG.pdf](https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_SCHEDULES_AG.pdf)

[28] "Consumer-Sited Renewable Energy Generation," California Public Utilities Commission, Energy Division, 2021, San Francisco CA, ca.gov.  
<https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/demand-side-management/net-energy-metering>

[29] “NEM2 Program Introduction,” PG&E Customer Services, San Francisco CA, ca.gov.  
[https://www.pge.com/en\\_US/residential/solar-and-vehicles/green-energy-incentives/solar-and-renewable-metering-and-billing/net-energy-metering-program-tracking/net-energy-metering-and-tracking-faq.page](https://www.pge.com/en_US/residential/solar-and-vehicles/green-energy-incentives/solar-and-renewable-metering-and-billing/net-energy-metering-program-tracking/net-energy-metering-and-tracking-faq.page)

[30] “Infrastructure,” California Public Utilities Commission, Electrical Energy Department, San Francisco CA, ca.gov.

<https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/infrastructure>

[31] “Community Choice Energy,” SLO City’s Office of Sustainability and Renewable Resources Climate Action, San Luis Obispo CA, slocity.org.

<https://www.slocity.org/government/department-directory/city-administration/office-of-sustainability-and-natural-resources/climate-action/community-choice-energy>

[32] “Community Choice Aggregation,” PG&E Customer Service, Alternative Energy Providers, San Francisco CA, pge.com.

[https://www.pge.com/en\\_US/residential/customer-service/other-services/alternative-energy-providers/community-choice-aggregation/community-choice-aggregation.page](https://www.pge.com/en_US/residential/customer-service/other-services/alternative-energy-providers/community-choice-aggregation/community-choice-aggregation.page)

[33] “Learn about the Standard Net Energy Metering process and requirements,” PG&E Interconnection and Renewables, Solar/Wind Contractor Resources, San Francisco CA, pge.com.

[https://www.pge.com/en\\_US/for-our-business-partners/interconnection-renewables/simple-solar-wind/contractor-resources/standard-nem-process-and-requirements.page](https://www.pge.com/en_US/for-our-business-partners/interconnection-renewables/simple-solar-wind/contractor-resources/standard-nem-process-and-requirements.page)

[34] *ELECTRIC SCHEDULE NEM2 NET ENERGY METERING SERVICE*, CPUC No 55762-E, PG&E Tariff Books, Meredith Allen, San Francisco, February 2023.

[https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC\\_SCHEDULE\\_NEM2.pdf](https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_SCHEDULE_NEM2.pdf)

[35] “Net Energy Metering Multiple Tariff overview,” PG&E Interconnection and Renewables, Net Energy Meetering, San Francisco CA, ca.gov.

[https://www.pge.com/en\\_US/for-our-business-partners/interconnection-renewables/net-energy-metering/nem-multiple-tariff.page](https://www.pge.com/en_US/for-our-business-partners/interconnection-renewables/net-energy-metering/nem-multiple-tariff.page)

[36] "Discover Net Metering Aggregation," PG&E Solar and Vehicles, How to Get Started, San Francisco CA, pge.com.

[https://www.pge.com/en\\_US/residential/solar-and-vehicles/options/option-overview/how-to-get-started/nema/net-energy-metering-aggregation.page](https://www.pge.com/en_US/residential/solar-and-vehicles/options/option-overview/how-to-get-started/nema/net-energy-metering-aggregation.page)

[37] "Net Energy Metering," Central Coast Community Energy Rates, San Luis Obispo CA, 2022, 3cenergy.org. <https://3cenergy.org/billing/nem/>

[38] "Net Surplus Compensation Rates for Energy," PG&E Table Per D.11-06-016, San Francisco CA, 2022, pge.com.

[https://www.pge.com/pge\\_global/common/pdfs/solar-and-vehicles/green-energy-incentives/AB920\\_RateTable.pdf](https://www.pge.com/pge_global/common/pdfs/solar-and-vehicles/green-energy-incentives/AB920_RateTable.pdf)

[39] CPUC, Decision 11-06-016. (June 9, 2011). *DECISION ADOPTING NET SURPLUS COMPENSATION RATE PURSUANT TO ASSEMBLY BILL 920 AND THE PUBLIC UTILITY REGULATORY POLICIES ACT OF 1978*

[https://docs.cpuc.ca.gov/PUBLISHED/FINAL\\_DECISION/137431.htm](https://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/137431.htm)

[41] "California's New Solar Billing Program," PG&E, San Francisco CA, February 2023, pge.com.

[https://www.pge.com/pge\\_global/local/assets/data/en-us/solar-renewables/green-energy-incentives/solar-and-renewable-metering-and-billing/how-to-read-your-bill/nem-faq.pdf](https://www.pge.com/pge_global/local/assets/data/en-us/solar-renewables/green-energy-incentives/solar-and-renewable-metering-and-billing/how-to-read-your-bill/nem-faq.pdf)

[42] "*Non-Bypassable Charges* definition," Law Insider, lawinsider.com.

<https://www.lawinsider.com/dictionary/non-bypassable-charges>

[43] *Distribution Interconnection Handbook*, PG&E, San Francisco CA, 2017.

<https://www.pge.com/includes/docs/pdfs/shared/customerservice/nonpgeutility/electrictransmission/handbook/distribution-interconnection-handbook.pdf>

[44] “NEM Revisit Proceeding (R) 20-08-020,” CPUC Demand Side Management, San Francisco CA, December 2022, cpuc.gov. <https://www.cpuc.ca.gov/nemrevisit>

[45] “ Frequently Asked Questions Ruling – Net-Energy Metering Tariff Revisit Proceeding,” CPUC Demand Side Management, San Francisco CA, May 2022, cpuc.gov.

<https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/demand-side-management/net-energy-metering/nem-revisit/frequently-asked-questions>

[46] “Net Billing Tariff,” CPUC Demand Side Management, San Francisco CA, cpuc.gov.

<https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/demand-side-management/net-energy-metering/nem-revisit/net-billing-tariff>

[47] “What is an Advice Letter?” CPUC Water Division, San Francisco CA, cpuc.gov.

<https://www.cpuc.ca.gov/about-cpuc/divisions/water-division/wd-advice-letters-section/wd-about-advice-letters>

[48] “Summary of G.O. 96-B Rules for the Telecommunications Industry Advice Letter Types,” CPUC Communications and Telecommunications, San Francisco CA, September 2019, cpuc.gov.

[https://www.cpuc.ca.gov/-/media/cpuc-website/files/uploadedfiles/cpuc\\_public\\_website/content/utilities\\_and\\_industries/communications\\_-\\_telecommunications\\_and\\_broadband/service\\_provider\\_information/final-al-tiers-summary.pdf](https://www.cpuc.ca.gov/-/media/cpuc-website/files/uploadedfiles/cpuc_public_website/content/utilities_and_industries/communications_-_telecommunications_and_broadband/service_provider_information/final-al-tiers-summary.pdf)

[50] “Renewable Natural Gas Production,” U.S. Department of Energy, Energy Efficiency and Renewable Energy, Alternative Fuels Data Center, Washington DC, energy.gov.

[https://afdc.energy.gov/fuels/natural\\_gas\\_renewable.html](https://afdc.energy.gov/fuels/natural_gas_renewable.html)

[51] "Active Solar Heating," U.S. Department of Energy, Energy Saver, Washington DC, energy.gov. <https://www.energy.gov/energysaver/active-solar-heating>

[51] Paul Breeze, "Chapter 8 - Hydrogen Energy Storage," Editor(s): Paul Breeze, Power System Energy Storage Technologies, Academic Press, 2018, Pages 69-77, ISBN 9780128129029, <https://doi.org/10.1016/B978-0-12-812902-9.00008-0>.

<https://www.sciencedirect.com/science/article/pii/B9780128129029000080>

[52] "Non-export interconnection," PG&E Interconnection and Renewables, San Francisco CA, pge.com.

[https://www.pge.com/en\\_US/for-our-business-partners/interconnection-renewables/larger-self-generation-programs/non-export/non-export.page](https://www.pge.com/en_US/for-our-business-partners/interconnection-renewables/larger-self-generation-programs/non-export/non-export.page)

[53] "Standard NEM Engineering Review/Electric Rule 21 Engineering Decision Tree," PG&E Interconnection and Renewables, San Francisco CA, pge.com.

[https://www.pge.com/pge\\_global/common/pdfs/for-our-business-partners/interconnection-renewables/StandardNEMEngineering.pdf](https://www.pge.com/pge_global/common/pdfs/for-our-business-partners/interconnection-renewables/StandardNEMEngineering.pdf)

[54] GE Digital Energy, "Commercial & Industrial Electricity Metering," General Electric, Atlanta Georgia. [https://www.gegridsolutions.com/products/brochures/kv2-family\\_gea-12673.pdf](https://www.gegridsolutions.com/products/brochures/kv2-family_gea-12673.pdf)

[55] K.C. Agrawal, "Temporary over-voltages and system grounding," in *Electrical Power Engineering Reference and Applications Handbook*, Oxford UK, Butterworth Heinemann, 2012.

<https://www.electricalengineering-book.com/pdf/chapter-754953.pdf>

[56] Monterey Bay Community Power, "MBCP Energy Programs Policy," Central Coast Community Energy, 3cenergy.org

<https://3cenergy.org/wp-content/uploads/2022/06/MBCP-CEA2-Energy-Programs-Policy-Amended-20190626.pdf>

[57] *California Energy Code (Title 24)*, 2022 Edition, California Building Standards Commission, Sacramento CA, 2022. <https://up.codes/viewer/california/ca-energy-code-2022>

[58] “2022 Building Energy Efficiency Standards,” California Energy Commission, Title 24, Sacramento CA, 2022, energy.ca.gov.

<https://www.energy.ca.gov/programs-and-topics/programs/building-energy-efficiency-standards/2022-building-energy-efficiency>

[59] California Energy Commission, “About,” energy.ca.gov. <https://www.energy.ca.gov/about>

[60] M. Mahon and S. Wurmlinger, “Evolving requirements in solar + storage industry,” *PV Magazine*, March 2022.

<https://pv-magazine-usa.com/2022/03/31/evolving-requirements-in-the-solar-storage-industry/>

[61] *DISTRIBUTED GENERATION PROTECTION REQUIREMENTS*, 094681, Daniel Jantz, PG&E, February 2023.

<https://www.pge.com/includes/docs/pdfs/shared/customerservice/nonpgeutility/electrictransmission/handbook/094681.pdf>

[62] “Appendix R: Protective Relay Requirements and Approvals,” in *PG&E Interconnection Handbook*, PG&E, 2015.

[https://www.pge.com/includes/docs/pdfs/shared/rates/tariffbook/ferc/tih/app\\_r.pdf](https://www.pge.com/includes/docs/pdfs/shared/rates/tariffbook/ferc/tih/app_r.pdf)

[63] *UL Product iQ*, (2023) Underwriter Laboratories Solutions

<https://productiq.ulprospector.com/en/search>

[64] “Section G2 PROTECTION AND CONTROL REQUIREMENTS FOR TRANSMISSION GENERATION ENTITIES,” in *PG&E Transmission Interconnection Handbook*, PG&E, June 2022.

<https://www.pge.com/includes/docs/pdfs/shared/rates/tariffbook/ferc/tih/g2.pdf>

[65] “Point-To-Point Method of Short-Circuit Calculation,” Benha University, Banha Egypt, 2019.  
[https://www.bu.edu.eg/portal/uploads/Engineering,%20Shoubra/Electrical%20Engineering/2904/crs-10562/Files/mohamed%20abd%20elwahab%20ali\\_Lecture%2007.%20Short%20Circuit%20Calculations.pdf](https://www.bu.edu.eg/portal/uploads/Engineering,%20Shoubra/Electrical%20Engineering/2904/crs-10562/Files/mohamed%20abd%20elwahab%20ali_Lecture%2007.%20Short%20Circuit%20Calculations.pdf)

[66] *Electric & Gas Service Requirements (Greenbook)*, PG&E, San Francisco CA, 2023.  
[https://www.pge.com/pge\\_global/common/pdfs/services/building-and-renovation/greenbook-manual-online/greenbook\\_manual\\_full.pdf](https://www.pge.com/pge_global/common/pdfs/services/building-and-renovation/greenbook-manual-online/greenbook_manual_full.pdf)

[67] *SUPPLY SIDE INTERCONNECTION REQUIREMENTS FOR DISTRIBUTED GENERATION*, 094670, Albert Pham, PG&E, September 2020.

[https://www.pge.com/pge\\_global/common/pdfs/services/building-and-renovation/greenbook-manual-online/094670.pdf](https://www.pge.com/pge_global/common/pdfs/services/building-and-renovation/greenbook-manual-online/094670.pdf)

[69] *Integration Capacity Analysis Map*, (2022), PG&E.

[https://www.pge.com/b2b/distribution-resource-planning/downloads/integration-capacity/PGEICA\\_Map\\_User\\_Guide.pdf](https://www.pge.com/b2b/distribution-resource-planning/downloads/integration-capacity/PGEICA_Map_User_Guide.pdf)

[71] PG&E Interconnection and Renewables, “Tips and advice for application process,” pge.com.

[https://www.pge.com/en\\_US/for-our-business-partners/interconnection-renewables/simple-solar-wind/contractor-resources/application-process-tips.page?ctx=large-business#aa](https://www.pge.com/en_US/for-our-business-partners/interconnection-renewables/simple-solar-wind/contractor-resources/application-process-tips.page?ctx=large-business#aa)

[72] Jay Cee, “Basic Parts of a Distribution Transformer,” Pinoy Electrical Engineer, pinoyelectricalengineer.com

<https://pinoyelectricalengineer.com/basic-parts-of-a-distribution-transformer/>

[73] Eaton, “General duty cartridge fuse safety switch,” DG221NRB datasheet,  
<https://www.eaton.com/us/en-us/skuPage.DG221NRB.html>

[74] Sharon Lee, "Line Side Tap vs. Load Side Tap: Everything You Need To Know," Velo Solar, Atlanta Georgia, January 2023, [velosolar.com](https://www.velosolar.com/line-side-tap-vs-load-side-tap/)

<https://www.velosolar.com/line-side-tap-vs-load-side-tap/>

[76] Adam Diehl, *Determining Module Inter-Row Spacing*, Greentech Renewables, Little Rock AR, March 2020. [greentechrenewables.com](https://www.greentechrenewables.com/article/determining-module-inter-row-spacing)

<https://www.greentechrenewables.com/article/determining-module-inter-row-spacing>

[77] SDG&E, *Photovoltaic Site Energy Storage Systems Analysis and System Sizing*, San Diego CA. [sdge.com](https://www.sdge.com/sites/default/files/Photovoltaic%20Site%20Energy%20Storage%20Systems%20Analysis%20and%20System%20Sizing%20%203.pdf)

<https://www.sdge.com/sites/default/files/Photovoltaic%20Site%20Energy%20Storage%20Systems%20Analysis%20and%20System%20Sizing%20%203.pdf>

[78] PG&E Customer Service, "Voltage Imbalance and Motors," PG&E, San Francisco CA, October 2009, [pge.com](https://www.pge.com/includes/docs/pdfs/mybusiness/customerservice/energystatus/powerquality/voltage_unbalance_rev2.pdf)

[https://www.pge.com/includes/docs/pdfs/mybusiness/customerservice/energystatus/powerquality/voltage\\_unbalance\\_rev2.pdf](https://www.pge.com/includes/docs/pdfs/mybusiness/customerservice/energystatus/powerquality/voltage_unbalance_rev2.pdf)

[79] Michael Ginsberg, "The hidden hazards of ground faults in PV systems," Fluke Grounding and Renewable Energy, Everett WA, [fluke.com](https://www.fluke.com/en-us/learn/blog/grounding/dc-ground-faults-pv-systems)

<https://www.fluke.com/en-us/learn/blog/grounding/dc-ground-faults-pv-systems>

[80] *Short Circuit Current Calculations For Industrial and Commercial Power Systems*, General Electric Distribution and Control, Plainville CT, 1989.

<https://library.industrialsolutions.abb.com/publibrary/checkout/GET-3550F?TNR=White%20Pages%7CGET-3550F%7Cgeneric>

[81] M. Holt, "Voltage Drop Calculations," Mike Holt Enterprises, Leesburg FL, 2011, [mikeholt.com](https://www.mikeholt.com/technical-voltage-drop-calculations-part-one.php) <https://www.mikeholt.com/technical-voltage-drop-calculations-part-one.php>

[82] Turcotte, Dave & Katiraei, F.. (2009). Fault contribution of grid-connected inverters. IEEE Electrical Power Conference. 10.1109/EPEC.2009.5420365.

[https://www.researchgate.net/publication/237354023\\_Fault\\_contribution\\_of\\_grid-connected\\_inverters](https://www.researchgate.net/publication/237354023_Fault_contribution_of_grid-connected_inverters)

[83] LG Home Batteries, *Installation Manual for RESU10H Prime*, Version 1.02, LG Energy Solution ESS Battery Division, Seoul South Korea, 2021.

[https://lghomebatteryblog.eu/wp-content/uploads/RESU10H-PRIME\\_IM\\_ENG\\_210511\\_low.pdf](https://lghomebatteryblog.eu/wp-content/uploads/RESU10H-PRIME_IM_ENG_210511_low.pdf)

[84] *Standard for Electrical Safety in the Workplace*, NFPA 70E, National Fire Protection Agency, 2021. <https://link.nfpa.org/free-access/publications/70E/2021>

[85] CPUC, Decision 22-12-056, (December 15, 2022). *DECISION REVISING NET ENERGY METERING TARIFF AND SUBTARIFFS*.

<https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M500/K043/500043682.PDF>

[86] PG&E/CPUC, Advice 6848-E, (January 30, 2023). *Creating Pacific Gas and Electric Company's New Net Billing Tariff (NBT) Rate Schedule Per Decision (D.) 22-12-056, Ordering Paragraphs 12b*. Available: CPUC Advice Letter Database

[87] *GENERATING FACILITY INTERCONNECTIONS*, Electric Rule No. 21, M. Allen and R. Kenney, PG&E, June 30 2023.

[88] *DESCRIPTION OF SERVICE*, Electric Rule No. 2, B. Cherry and R. Kenney, PG&E, 2008.

[89] *APPLICATION FOR SERVICE*, Electric Rule No. 3, B. Cherry and R. Kenney, PG&E, 2020.

[90] *DISTRIBUTION LINE EXTENSIONS*, Electric Rule No. 15, R. Kenney, PG&E, 2021.

[91] *SERVICE EXTENSIONS*, Electric Rule No. 15, R. Kenney, PG&E, 2020.

[92] *California Electrical Code (adopts with amendment NFPA 70 2020)*, Year 2022, California Building Standards Commission, Sacramento CA.

<https://up.codes/viewer/california/ca-electric-code-2022/chapter/introduction/introduction#introduction>

[93]"IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces," in *IEEE Std 1547-2018 (Revision of IEEE Std 1547-2003)* , vol., no., pp.1-138, 6 April 2018, doi: 10.1109/IEEESTD.2018.8332112

[94] "2023 National Electrical Safety Code® (NESC®)," in *2023 National Electrical Safety Code(R) (NESC(R))* , vol., no., pp.1-365, 1 Aug. 2022, doi: 10.1109/IEEESTD.2022.9825487.

[95] PG&E, "Tariffs," pge.com <https://www.pge.com/tariffs/index.page>

All pg&e forms can be located here

[96] CPUC. "Solar Equipment List Program," CPUC Programs, Sacramento CA, Updated 1st, 11th and 21st of each month, energy.ca.gov.

<https://www.energy.ca.gov/programs-and-topics/programs/solar-equipment-lists>

[97] *Hybrid Inverter A-ES Series User Manual*, Version V1.6-2022-01-05, GoodWe, Suzhou China, 2022.

[98] *PV Master App User Manual*, Version V1.2 -2022 -09-30, GoodWe, Suzhou China, 2022.

[99] *Switching Devices*, Version 1.1, PG&E, San Francisco CA, August 2015.

[https://www.pge.com/includes/docs/pdfs/shared/customerservice/nonpgeutility/electrictransmission/handbook/CrossReference\\_Eaton.pdf](https://www.pge.com/includes/docs/pdfs/shared/customerservice/nonpgeutility/electrictransmission/handbook/CrossReference_Eaton.pdf)

# Appendices

## 1)SLO Circuit Electrical Invoice



From **SLO CIRCUIT ELECTRICAL**  
1375 Nipomo Ave  
Los Osos, CA 93402  
(805) 235-4278  
C10 LICENSE #951325

Invoice ID	<b>1750</b>	Invoice For	<b>CITY FARM</b>
Job Name	CITY FARM		
Issue Date	04/17/2019		
Due Date	04/17/2019 (upon receipt)		<b>paid 5/12/19; tg</b>
Subject	CITY FARM SLO 3.96 KW DC GROUND MOUNTED PV SYSTEM		

Item Type	Description	Quantity	Unit Price	Amount
Service	(12) TRINA SOLAR 330W MODULES TSM-PE14-330 *25 YEAR POWER WARRANTY  (1) SMA AMERICA 3,800W INVERTER SMA SB3.8-1SP-US-40 *10 YEAR WARRANTY  ANODIZED SNAPNRACK ALUMINUM RACKING  1.5" GALVANIZED STEEL STRUCTURE  INCLUDES ALL DESIGN, PERMITTING, INSTALLATION, INTERCONNECTION FEES AND PAPERWORK  10 YEAR WARRANTY ON ALL WORKMANSHIP  ESTIMATED YEAR ONE PRODUCTION: 6,712 KWH @ 200 DEG. SW 6,098 KWH @ 110 DEG ESE  INCLUDES DIGGING OF FOOTINGS AND TRENCHING  INCLUDES CONCRETE AND CONCRETE MIXER RENTAL	1.00	\$8,125.00	<b>\$8,125.00</b>
			<b>Amount Due</b>	<b>\$8,125.00</b>

## **2) Equipment lists**

Cross Reference for Safety Switches - Eaton

[https://www.pge.com/includes/docs/pdfs/shared/customerservice/nonpgeutility/electrictransmission/handbook/CrossReference\\_Eaton.pdf](https://www.pge.com/includes/docs/pdfs/shared/customerservice/nonpgeutility/electrictransmission/handbook/CrossReference_Eaton.pdf)

## **3) Inverter Programming**

We will leave the inverter at its default settings except to only allow it to charge during the following times 12:30am-3:30am. This, as discussed, is to prevent the battery from drawing too much current while other loads are being used and overloading the service transformer.

## **4) Theoretical Forms**

We fill out PG&E forms as an academic exercise. We expect that whatever professional engineering company who actually submits any of these forms will verify they are correct (or fill out blank ones themselves) and will thus take any responsibility for their submission. The forms should not be submitted without licensed engineer overview and assumption of any liability. All forms locateable at [95] and filled out versions will be attached with the project submission.

## **5) ABET Analysis**

### **1. Summary of Functional Requirements**

The microgrid design takes a mix of renewable resources, battery storage, to further reduce imported electricity demands with the expectation that additional electrical loads will be built in the near future. Additionally, it will be able to safely provide back up power in the event that the PG&E grid is de-energized. It will supply power to the water pumps, AC units, various chargers, a barn that is fully electrified (the expected new loads), and the ability to add more loads as they please. The overall purpose is that when more of the farm's tools become electrified, they have the infrastructure and the clean energy to supply this power. A battery management system will be implemented with an interactive "smart" inverter. The smart inverter will prioritize energy sourced from the solar panel and battery resource. The connection to the

grid will only be used only as needed. A microgrid will reduce the dependency on the grid, increase site resilience and promote renewables.

## **2. Primary Constraints**

The main constraints from the project come from financial feasibility, uncertainty of the future, and inability/unwillingness to obtain aid of a licensed professionals. This translated to a somewhat incomplete understanding of the site's current load panels and tested student ability to locate and parse through codes, rules, schedules and other documents. Too long was spent trying to apply the CPUC's NBT Tariff to old PG&E schedules when there was a relevant PG&E NBT Schedule available (although in a difficult to find location). Perhaps a professional would have quickly directed us to all the relevant documents. Our interpretations of the various and lengthy documents we find to apply are surely deficient in some regard. Not having a professional to check interpretations against leads to much second guessing, re-interpretation, and re-working. Not enlisting professional aid to open certain boxes and help chart the connection of existing loads and the size of the service prevented us from completing certain designs and designing with full confidence. It also prevented us from installing equipment to concretely measure the usage factors and power demand of loads.

Additionally, it is unknown how much energy will be consumed in the future. After a full load profile was completed, there is a minimum constraint on how much energy will need to be stored, but it is the max value that needs to be planned for. They want new developments that will require more power draw. Money will constrain the size of the battery because as the storage increases, the price of the battery will be exponential. This then relies heavily on the instantaneous energy production on the solar panels so the use of the batteries are decreased. Solar panels are also constrained by the solar resource.

### **3. Economic**

The economic impacts of this project on City Farm are represented by a large initial investment (in terms of both money and personal hour administrative resources) with an incremental long term monetary savings on electricity and a long term person hour commitment to maintaining the microgrid system. We expect the ability for City Farm to advertise and teach children with/about the new improved microgrid will help them secure donations, although we do not quantify this. While administrative man hour costs are harder to quantify and we expect their administrative staff to efficiently communicate with whatever company contracts to perform maintenance (that contract must be part of the initial construction process). The failure of a larger component could mean time not generating electricity, but every component over \$150 is warranted for 10 or more years so replacement should not be expensive.

For the broader economy, it increases demand for inverter/electrical components and administrative resources of the authority having jurisdiction today while decreasing demand for electrical energy from the broader electrical grid long term. It will require initial construction and inspection and commission testing work and also ongoing services from both PG&E and the company that performs maintenance. Many components in our electronics, batteries and solar panels must be mined, manufactured and imported. Mining comes at a human and environmental cost, especially when it is undertaken outside of the Untied States. It is often dangerous and physically degrading work that can increase public health costs as well as create expensive or messy problems in the environment. Then the manufacture of electronics implies cost as well. This work has a smaller human cost but can cause problems to the environment of similar scale. Whether we then import raw materials or more processed goods (in terms of the components needed for this project), importation of anything adds to the terrible snarl of international transportation in the late 2010s and early 2020s. Financially, it means money flowing out of the United States economy, not to be recouped by any export from the small

community farm. Although you could perhaps argue that the engineering experience can be exported for profit and the drive towards renewable energy generation may lend the United States credibility on the international stage.

The timing of the project going forward is in City Farm' hands. We recommend that they begin working with the professional engineering company to finalize a licensed microgrid design at around the same time, or a few months before, they begin working with whoever will build their new barn. These companies should be in contact to best fine tune the microgrid to the new barn load. The AHJ and PG&E review process for the microgrid will likely take longer than the review process for the barn though. This should be accounted for but we also note that the submission of review documents to PG&E cannot happen more than 12 months before the barn's construction and electrical connection is done.

#### **4. If manufactured on a commercial basis**

The product is specific to SLO City farm solely. The idea of a microgrid used for a full scale farm is a relatively new concept. Though the amount of components, such as the panels and battery size, is roughly proportional to load demands across some farms, many other aspects like protection, location and orientation of components, conduit lengths, etc must be very specifically tailored to the farm's site and loads. Both PG&E and CEC considerations are unable to be abstracted to a platonic "ideal farm." Even self contained systems marketed for residential application takes a significant amount of engineering work to implement.

#### **5. Environmental**

SLO City farm's microgrid will reduce carbon emissions due to the system's reliance on

renewable resources. The grid still has a majority of its generation from fossil fuels and it is important to reduce the demand of unclean energy. The project also promotes growth in electrification because the source it draws from is renewable. It should be used as a model to other farms that it is possible to decrease their carbon footprint.

The solar panels and batteries are not completely recyclable and will need to be replaced typically after 20 years. Though solar is a renewable resource, the panels are not completely sustainable. The materials used to develop them require materials that are not in surplus.

## **6. Manufacturability**

The project requires a large amount of power electronics for generation and transmission of the power. The manufacturability of this product does vary depending on the size of the customer. As the farm gets larger, batteries, conduit, solar panels, and the amount of protection needed will increase.

For our specific project though, the components will be purchased on a one-off basis. All parts are required to be outsourced so no portion of the project will be manufactured by the senior project partners. We thus do no real contemplation on the manufacture of the components aside from their economic and environmental impacts.

## **7. Sustainability**

The microgrid design will act as a model to promote sustainability and how anyone is capable of decreasing their carbon footprint. The use of renewable generation increases the demand for jobs in this sector. Even the construction of the project needs outside labor to install

solar panels, batteries, switches, fuses, and the panel box. A feasible implementation of a microgrid will decrease the cost of components needed to develop the product. There are though only limited quantities of the metals and elements used to produce the electronics. If not efficiently recycled or otherwise reclaimed, they will run out.

## **8. Ethical**

The need for mined and manufactured materials that have little likelihood of reuse or recycling is unsustainable and do pose something of an ethical dilemma. Is it right to combat one effect of unsustainable practice (greenhouse emissions) with another (mineral usage)? In this case the answer seems to be yes, although it depends to a large degree on how well the original problem is addressed and what the negative effects of the new problem are. In the current situation extreme weather events, wider temperature swings and their detrimental effects on crops and beings, the heating of the oceans and their resulting rise and poor air quality all are issues with the potential to adversely affect huge portions of the global population. The wealthier will be able to insulate themselves more but for many funding for climate mitigation may not be available. Weigh that against the other negative effects of industrial activities. At least some associated jobs have dangerous, unhealthy or exploitative working conditions. The materials involved can be toxic, especially if not handled or disposed of correctly. The materials are limited, and when we run out something will have to happen.

It is easy to say the global warming problem is more important, whether or not that is correct or compassionate. Global warming has the potential to damage the citizens of entire nations while the damage of mine or industrial work is limited to regions or communities. Disposing of materials irresponsibly can greatly harm ecosystems, but materials can often be collected at least in part and their negative effects tend to be local to the site. While the

environmental damage due to warming is more widespread and it is harder for individuals or even large organizations to rectify independently. At some point there may be a reckoning where we run out of certain minerals and struggle to source them at all, but that seems farther off than the impending climate disaster, whose real effects will be felt by the end of the century. This analysis could be misguided. The global warming issue is more pressing in the medium term and is “the issue” currently under scrutiny by our institutions. We may be doing irreparable harm somewhere as we combat climate change in this way, but the harm that this author can quantify seems to pale in comparison to global warming.

## **9. Health and Safety**

The protection aspect of the system is a huge consideration. If improperly designed or installed harm can come to installers, maintenance personnel, PG&E personnel, City Farm personnel, electrical equipment owned both by City Farm and PG&E, other infrastructure on City Farm’s site, the soil and City Farms crops. The documents we spend so much time reading through and applying to the design are intended to minimize the chances of this by as much as possible. But even if our design met all requirements perfectly things happen. Working with even distribution and secondary level voltages is very dangerous and must only be performed by licensed individuals. There will be children on the site and they present a larger safety concern as they are less likely to follow “common sense” safety protocols around electrified equipment. We try to account for this where possible within the strictures of the code. There is also a concern that this is a farm that grows crops for human consumption. The system cannot in any way leach toxic chemicals into the ground as they could find their way into the farm’s consumers’ bodies. The biggest worry in this leakage from the battery as it ages. We have specified a battery that is outdoor rated and is large compared to the back up load it powers so

as to not be forced into deep discharge (in an effort to extend its longevity).

## **10. Social and Political**

The project will impact various stakeholders in our society. The primary stakeholder, the farm's operators, should see mostly benefits: cheaper operation, less contribution to greenhouse effect, more reliable electrical service, and increased prominence in the sustainability conscience community. It is only if something goes wrong that their interests would be injured, say an electrocution or toxic run off. Another primary stakeholder is the utility company PG&E. It is usually cheaper for them to supply a reduced load. Their grid's efficiency can be supported if the system buys and sells energy from PG&E at the correct times, when demand for power is relatively low or high. Some secondary stakeholders are the farm's consumers who should benefit from increased farm production associated with more accessible electricity as long as the produce is in no way contaminated. More secondary stakeholders are the people living in the surrounding area that see the farm. The farm already has solar panels and the farm's operators see it as in their interest for the panels to be visible. There could be NIMBYs opposed to seeing panels. However, much larger solar farms are just as visible from the same freeway not 20 miles north of City Farm. These were allowed to be installed.

An element of this project could be seen as unfair. One could argue that when the government sponsors electrification, money generally flows to those better off than the median American. For example, when solar panels are subsidized, money collected from taxpayers at every level is spent to make panel installation cheaper (perhaps through a rebate). But the people installing private solar panels tend to be more economically privileged. They generally own enough land or a house with enough roof space to put panels on. Even with government assistance, they must have the capital to invest in panels to receive benefits. These are two barriers to entry generally met only by the relatively well off. So in some peoples' view subsidies

of this nature represent something of a regressive social program. While the CPUC has taken steps in their new tariff to reverse the regressiveness of solar panel financing and crediting systems and every dollar spent on a panel means less CO2 and less environmental cost/harm to everyone, seeking and accepting money on this basis does have societal and political consequences.

## **11. Development**

We read a lot about the way that California regulates electrical projects and utilities, the PG&E interconnection process and its mandates, and the codes that ensure electrical safety on the local system. The analysis we provide about these regulations and codes took a lot of work as we wanted our design to be as consistent with them as possible and we wanted to explain our reasoning as much as possible. Ruminating on and regurgitating all of the information seemed helpful for us, from when we first started to make heads or tails out of it, all the way until when we used the information to inform our design. We gained experience specifying individual components, loading and reading through data sheets/manuals and sourcing the components. Some items on the Solar equipment list are difficult to source, others are incompatible with each other, we made efforts to be consistent on those points as well as try and use less expensive components. We got to fill out PG&E forms and put together a site plan. The plans forced us to use arcGIS which we were not familiar with; but with it we were able to draw on a google map and take accurate measurements. The site plan was something of the culminating effort, the product that we have to show. We had some experience putting one together, but organizing one entirely from scratch, without a document to go-by, encouraged us to make choices about how to organize our own document and really double check that our document included everything we thought it needed. This writer perhaps learned lessons about how to work in a

team, specifically how to set and assess expectations between multiple people and divide work.