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The Role of Community Distributed Energy in Zero Net Energy Compliance

Final Report

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CALMAC Study ID # PGE0409.01

Submitted To:

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I. Acknowledgements

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2. Executive Summary

California's solar and biomass markets are driven by the state's Renewable Portfolio Standard (RPS) established in 2002 with the passage of Senate Bill (SB) 1078, and accelerated in 2006 under SB 107. The passage of SB-43 created the Green Tariff Shared Renewables (GTSR) Program which included a Green Tariff (GT) option component and an Enhanced Community Renewables (ECR) component for the solar market. In September 2012, SB 1122 was signed into law, requiring a 250 MW of renewable feed-in tariff (FIT) procurements from community-scale bioenergy projects (three MW or smaller), and the BioMAT tariff mechanism was established to implement SB 1122. The current community solar and biomass programs were developed without taking into consideration the state's Zero Net Energy (ZNE) goals and the Title-24 ZNE requirements. As California moves forward with the implementation of its renewable goals, the state is evaluating how to align its solar and biomass policies, markets, and programs with the implementation of its Zero Net Energy (ZNE) mandate for new residential buildings by 2020 and new commercial buildings by 2030.

The primary purpose of this research study was to evaluate the current barriers and opportunities for incorporating community-scale solar and biomass within Zero Net Energy buildings and communities. The TRC Team's research findings are based on a combination of literature review and data collection, interview research, and case study research. Key takeaways and lessons learned from the project are:

- The community solar market is positioned for growth at the national level. At least 18 states plus the District of Columbia have enacted community solar legislation and 40 states have at least one active community solar project. The market is expected to continue to evolve in terms of ownership models, financing mechanisms, regulatory mechanisms and program offerings.
- The California community solar market, however, is still in the nascent stage, the state has witnessed a slow implementation of SB-43, and the Green Tariff and the GTSR programs have shortcomings which have caused market adoption challenges.
  - The Green Tariff needs to overcome the barrier to high price premiums as compared to alternative options, and in its current form, it cannot compete with the currently lucrative NEM credit rate for rooftop solar.
  - The ECR program is off to a slow start during the first round.[1] Challenges include: low and uncertain bill credit; developer demonstration of community interest requirements; securities opinion requirement; and other compliance obligation barriers.[2]
- Selected municipal utilities such Sacramento Municipal Utilities Department (SMUD), Los Angeles Department of Water and Power (LADWP), City of Palo Alto Utilities (CPAU) have also announced new community solar programs with multi-megawatt targets and are setting up new program tariffs.
- California has a wide variety of biomass generation projects across the state in terms of the scale, technology, and applications. The high costs of producing biomass electricity have been at odds with the relatively low wholesale prices that California utilities are generally willing to pay for purchasing it. These

[1] https://www.greentechmedia.com/articles/read/a-rough-start-possible-reforms-for-californias-community-solar-program

[2] http://www.lawofrenewableenergy.com/2017/03/articles/solar/results-from-californias-first-community-solar-rfo/

projects also face other barriers that include procurement of raw materials, permitting requirements, complex financing arrangements, waste disposal and utility interconnection issues.

- Community solar and biomass market barriers can be addressed by utilities, local governments, and project financiers working together to develop enabling policies, regulations, incentives, and innovative business models.
- The grid impacts of continued growth in the community renewables markets continue to require new tracking mechanisms and deeper quantitative examination and need to be assessed in detail as these markets continue to gain prominence.
- *Role of community solar in ZNE implementation:* The community solar market can support ZNE implementation in California, but more work is needed to align California's community solar program with the emerging ZNE regulatory model. The current community solar program structure was developed without taking into consideration the state's ZNE goals and the Title-24 ZNE requirements. The ZNE mandate in Title-24 could provide an additional market impetus for the growth of this market and represent an untapped value stream for community solar.

The TRC Team's research findings provide an overview of important issues regarding the community solar and biomass market in California and across the country. The findings also reveal fundamental programmatic, regulatory, and business model components that need to be addressed before community solar and/or biomass can be considered a viable ZNE compliance option.

The TRC Team identified research gaps to provide recommendations for the scope of a Phase II study. Figure 26 includes the data needs, research methods, and next steps for addressing the following research objectives:

- Objective 1: Community Solar ZNE Business Models
  - *Case Study Examination:* The TRC Team provided readily-available information on the experiences of municipalities and organizations (e.g. U.C. Davis, Lancaster) and lessons learned from building departments regarding their experiences with the implementation of their community solar initiatives. A deeper dive into specific case studies from states that have had the most experience with community solar initiatives will be helpful to provide localized insights regarding barriers and challenges of implementation of community solar implications.
  - *Business Model Options Summary:* The TRC Team's research findings provide currently available information on community solar ownership models, value streams, tax issues, and other business model details. However, this is a vast area of inquiry and individual components need to be analyzed in detail to inform a material policy direction. The TRC Team recommends that Phase II of this project leverage Phase I findings to examine existing as well as new and innovative business models relative to documented best practices and stakeholder-driven criteria for alignment with CA ZNE goals. Such models could seek to lower the subscription costs for customers and allow deeper penetration into the low and medium income market.
  - *Recommended Business Model(s):* The TRC Team recommends leveraging resultant findings from preceding Phase II tasks to identify the most appropriate community solar business model to achieve the ZNE goals.
- Objective 2: Community Solar ZNE Regulatory Model
  - As discussed in Section 5.3, there are fundamental community solar programmatic, regulatory, and business model components that need to be addressed before it can be considered as a viable CEC ZNE compliance option. The objective of this task is to consider the most relevant compliance option for the viable business model(s) identified in Objective 1. The compliance options discussed in

Section 5.3 are a starting point for this investigation. Important issues and details need to be addressed including:

- Would community solar shares be an optional purchase at the time of house or building sale, or always bundled into the asset?
- Role of RECs in meeting residential and commercial ZNE goals, including the Green-e Energy requirement to retire them on behalf of the customer. Clarifying ineligibility of community solar projects to meet ZNE goals if the developer retires or sells RECs either fully or partially for non-ZNE purposes such as RPS.
- If an owner defaults on their mortgage, does the mortgage-holder then own a share of the system?

- Objective 3: Community Solar ZNE Tracking Methodologies and Grid Impacts
  - The TRC Team recommends examining available and theoretical energy accounting and tariff options (e.g. NEM, NNM, VOS, group billing etc.) to understand their impact on subscription rates, rate values, and the overall business case for community solar. Critical to this examination is a detailed understanding of grid impacts. This research should also identify any market gaps that need to be filled, and roles that utilities can play so community solar can become a viable option for ZNE implementation in California.

3. Introduction

3.1 Background

California's vibrant solar and biomass markets are driven by the state's Renewable Portfolio Standard (RPS)[3] established in 2002 with the passage of SB 1078[4], and accelerated in 2006 under SB 107. The RPS was further expanded in 2011 with SB X1-2[5] and SB 350[6] in 2015, and is jointly managed by the California Energy Commission (CEC) and California Public Utilities Commission (CPUC). The law requires most California utilities to meet specific renewable energy procurement targets until they reach a fifty percent renewable energy contribution by 2030. Utilities can generate power on-site, sell power, or export biogas to be eligible, but this could change the renewable energy credit or certificate (REC) type generated and affects the value to the project.

California classifies renewable projects into one of three Portfolio Content Categories (PCCs), with the RPS law specifying the amount required for each compliance period. The majority of the resources must come from "bundled" projects where a utility receives both the RECs and energy associated with an eligible RPS facility. "Unbundled" transactions are only for the RECs, and the energy is no longer considered "green" once unbundled. Demand for RECs and transfers in bioenergy and solar in California are tracked under the Western Renewable Energy Generation Information System (WREGIS).

These solar and biomass markets, and the regulations designed around them, are not designed with or coordinated with the Zero Net Energy (ZNE) goals established by the CPUC in the 2008 Energy Efficiency Strategic Plan (CPUC, 2008). For these ZNE goals, a solar system that has been 'bundled' or 'unbundled' per above, would not meet the requirements for renewable energy onsite since the RECs are used towards meeting the RPS and thus not dedicated to the buildings.

The Strategic Plan goals seek ZNE for all new residential construction by 2020 and all new commercial construction by 2030. Likewise, the CEC's 2011 Integrated Energy Policy Report (IEPR) created parallel ZNE goals and the 2013 IEPR (CEC, 2013) established a regulatory definition for ZNE buildings.[7] These jointly held goals are referred to as the "ZNE goals." A key example of financial state support that advances the ZNE goals is "*Proposition 39 (Prop 39): Clean Energy Jobs Act of 2012*" that will provide roughly $2.5 billion in funding for energy retrofits in schools over five years, some of which are currently aiming to achieve ZNE.[8]

In addition to establishing a regulatory definition of ZNE buildings, the 2015 IEPR also leaves open for discussion the topic of off-site community options:

"*For newly constructed low-rise homes that cannot accommodate onsite renewables, alternative compliance pathways that enable such buildings to meet ZNE Code building requirements must be developed. The ZNE Code*

[3] http://www.energy.ca.gov/portfolio/

[4] http://www.energy.ca.gov/portfolio/documents/documents/SB1078.PDF

[5] http://www.leginfo.ca.gov/pub/11-12/bill/sen/sb_0001-0050/sbx1_2_bill_20110412_chaptered.html

[6] http://www.energy.ca.gov/sb350/

[7] This definition was later updated by the CEC in the 2015 Integrated Energy Policy Report, pp. 41: http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-01/TN212017_20160629T154354_2015_Integrated_Energy_Policy_Report_Small_File_Size.pdf

[8] 8 https://www.pge.com/nots/rates/tariffs/tm2/pdf/GAS_3563-G.pdf

Building definition anticipates considering 'development entitlements' for off-site renewables, as a potential option for builders and developers. The ZNE definition clearly allows community solar as a possibility; approaches need to be identified that would make it administratively workable and cost-effective. Any option that relies on off-site renewable resources must allow for building department verification to ensure that the identified resources exist, that they are the correct size for offsetting the energy use of the buildings they are assigned to, and that their output of these resources is not already 'spoken for' by other approved developments." (2015 IEPR, pg.6)

"*There will be particular buildings or situations where it will be infeasible for the building to meet the onsite renewable energy resources component of the ZNE Code Building definition. If the ZNE Code Building is adopted as a requirement in the future, the Energy Commission will use normal building code practice to establish specific exceptions for these cases. Also, the ZNE Code Building definition anticipates the possibility of buildings satisfying renewable energy generation obligations off-site through 'development entitlements,' as long as these obligations are commitments that are formally recognized and enforceable by the applicable enforcement agency. An example would be community-based renewable energy resources, offsetting the energy consumption of a large number of homes in subdivisions, which were committed to and approved when the developer obtained planning permits for the subdivisions.*" (2015 IEPR, pg. 38)

In addition to supporting the explorations of community options mentioned above, the need for this study was also established through findings in the recent Residential ZNE Market Characterization report (TRC, 2015), which indicated a need to explore alternative paths for homes and communities to reach CA's ZNE goals. One of the major research recommendations from the Residential ZNE Market Characterization was to "Research Barriers and Opportunities for Community-Scale Distributed Energy Resources."

3.2 Study Purpose

Pacific Gas & Electric Company (PG&E), on behalf of the joint California (CA) Investor Owned Utilities (IOUs) contracted a team led by TRC Energy Services (TRC) to lead the Zero Net Energy (ZNE) Compliance Options for Distributed Energy Resources (DER): Phase 1 project (henceforth called "*ZNE Community Solar and Biomass Research Project Phase I*"). The project evaluated the current barriers and opportunities for incorporating community-scale solar and biomass within Zero Net Energy buildings and communities. This project is the first phase of a two-phase study on the role of Community Solar and Biomass in ZNE buildings and communities. This project provides foundational, qualitative information, with a deeper dive and more intensive data analysis to follow in Phase 2.

The research priorities for this study flow from the "*Road to ZNE*" project (TRC, 2012) completed under the 2010-12 EM&V Plan, the Residential ZNE Market Characterization study (TRC, 2015), and "An Evaluation Framework for Residential Zero Net Energy Buildings" (Douglas Mahone, 2014).

The project has the following two research goals with the following objectives:

- Goal 1: Research efforts into community-scale photovoltaics (PV) for residential and commercial customers
  - Objective 1: Explore and characterize the current permitting requirements associated with siting and sizing community-scale systems
  - Objective 2: Review any current and proposed tariff frameworks that equitably allocate costs and generation to individual units, ownership, and financing
  - Objective 3: Potential DER voltage, frequency, and other impacts on the grid, including utility role in tracking projects

- Goal 2: Research efforts into community-scale biomass for residential and commercial customers
  - Objective 4: Conduct 10 California biomass project case study reviews via a mix of literature reviews, interviews, and other methods

3.3 Research Limitations

This scoping study was focused on conducting a qualitative assessment of the research goals and objectives. The goal of this project was to provide foundational, qualitative information, with recommendations for a deeper dive and more intensive data analysis to follow in Phase II. The research tasks for this project were commensurately limited to data collection and analysis through literature review, surveys/interviews, and case study analysis. The findings represent data collection and analysis done by the team up to October 2017 and this report doesn't include any data which may have been available after that. Any additional research methodologies identified during this project were proposed for inclusion in Phase II of this project. The project team focused its research on DER issues on a "community" scale and did not consider projects, solutions, issues, and discussions that are specific to individual building scale or a larger utility-scale deployment.

3.4 Study Team

The project research team is led by TRC Energy Services and supported by its project partners Navigant Consulting, Inc. (Navigant), Research into Action (RiA), and TSS Consultants (TSS), hereinafter referred to as the TRC Team.

4. Research Methodology

4.1 Approach to Research

The TRC Team's approach to data collection and analysis focused on providing foundational, qualitative information through a step-by-step approach outlined in Figure 1. Overall, the TRC Team's methodology focused on data collection through "Secondary Data Collection" methods which included peer-based knowledge transfer and literature review, and "Primary Data Collection" which included data collection through interviews of industry stakeholders.

1. **Secondary Data Collection and Analysis through Peer Knowledge Exchange:** This step focused on leveraging the TRC Team's existing knowledge of the research issues and a peer knowledge exchange of ideas and lessons learned amongst our subject matter experts (SME's). The SMEs conducted a literature review of different perspectives (project developers, project evaluators, policy analysts) to collect and assess data for each research question against the following criteria:
    - Data Needs
    - Data Quality
    - Data Availability
    - Data Cost

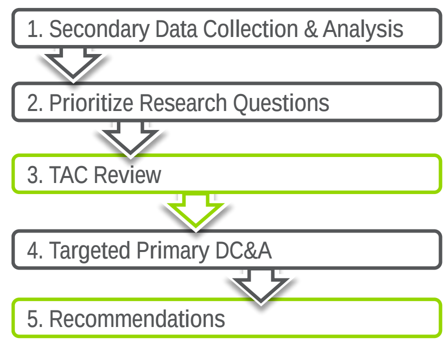

Figure 1: Five Step Process for Data Collection and Analysis

2. **Prioritize Research Questions and Preliminary Findings:** The TRC Team summarized preliminary research findings, identified knowledge gaps, and detailed data collection needs through primary data collection methods (e.g. interviews, surveys, etc.).
3. **TAC Review**: The project team presented the outputs from steps 1 and 2 to the Technical Advisory Committee (TAC) for review and incorporated TAC recommendations into the findings before proceeding with the primary data collection.
4. **Targeted Primary Data Collection and Analysis**: The TRC Team conducted 17 in-depth interviews with stakeholders and market actors. The TRC team identified several key stakeholders including developers, municipalities, utilities, community choice aggregators (CCA's), regulators, policymakers, and researchers. The TRC team identified multiple contacts within each group and attempted to complete interviews with two to four contacts for each stakeholder type. The TRC Team identified 10 biomass projects in California and identified key contacts from those projects for the primary data collection associated with objective IV. Finally, the TRC Team developed an interview guide to explore the project's research goals and objectives through the in-depth interviews.
5. **Recommendations**: The TRC Team analyzed the collected data through the above-mentioned steps and summarized the synthesized findings in Section 5 (community solar) and Section 6 (biomass). The research gaps and issues that require additional inquiry appear as recommendations for Phase II research in Section 7.

4.2 Literature Review and Subject Matter Expert (SME) Knowledge Exchange

The TRC Team included a sub-team of eleven SMEs (SME Team) with deep knowledge in the fields of community solar, distributed energy resources (DER) management, and biomass. The SME Team was asked to identify the most relevant sources of literature and data for answering the project research questions, including the literature resources identified by the project RFP and the project research plan. The SME Team subsequently analyzed each literature and data resource as to its relevance and adequacy to address the data needs of each research question. The SME Team used the following prioritization criteria to rate each available source:

- **Data Needs**: Level to which source meets technical and market data requirements to answer the research question from a CA policy standpoint.
- **Data Quality**: Suitability of technical and market data to answer questions from a CA policy standpoint.
- **Data Availability**: SME determination as to whether sufficient data sources had been identified to answer the research question.
- **Data Cost**: SME determination as to whether the level of effort required to collect and analyze primary data to address the research question fit within the Phase I project scope of a qualitative assessment.

The SME Team reviewed 92 data sources in the library. A sample of the SME team prioritization results appears in Figure 2.

Figure 2: TRC Team's SME Secondary Data Collection Library and Prioritization Results

4.3 Technical Advisory Committee (TAC)

The TRC Team assembled a qualified Technical Advisory Committee (TAC) to guide the data collection and analysis process based on their contribution to the national and CA-specific DER technology, policy, and implementation or research landscape. The TAC Team members are listed below in Figure 3. The TAC Team meeting was held on April 24, 2017, at which the TRC Team members presented the literature sources and the prioritization ratings by the SME team. The TAC team members were asked to identify data gaps and supplement the TRC Team's identified sources with any additional resources as needed to complete the body of existing research for consideration in the study. The TAC Team's input was reviewed and analyzed by the TRC Team during the data analysis step of the project.

	Organization Name	Member
1	California Public Utilities Commission (CPUC)	Rory Cox
2	California Energy Commission (CEC)	Martha Brook
3	California Energy Commission (CEC)	Mazi Shirakh
4	California Energy Commission (CEC)	Bill Pennington
5	Pacific Gas & Electric (PG&E)	Patrick Hennigan
6	Southern California Edison (SCE)	Lori Atwater
7	Southern California Gas (SCG)/Sempra	Nathanial Tyler
8	San Diego Gas & Electric (SDG&E)	Lonnie Mansi
9	National Renewable Energy Laboratory (NREL)	Paul Torcellini
10	Lawrence Berkeley National Laboratory (LBNL)	Andy Satchwell
11	Lawrence Berkeley National Laboratory (LBNL)	Galen Barbose
12	Energy and Environmental Economics (E3)	Snuller Price
13	U.S. Department of Energy (DOE)	Odette Muncha
15	Code Cycle	Tom Garcia
16	City of Davis	Greg Mahoney
17	Code Cycle	Dan Suyeyasu
18	Arup	Meg Waltner

Figure 3: The Project Team Technical Advisory Committee (TAC) Members

4.4 Primary Data Collection

The TRC Team examined the SME's prioritization results and identified those questions that could not be adequately addressed by the available resources, but which fit within the Phase I project scope of a qualitative assessment. These questions were addressed through targeted interviews with industry stakeholders. Questions that fell outside the qualitative assessment scope (i.e. required quantitative analysis of primary data that were not available at the time of the study) were identified for investigation in Phase II of the project.

During primary data collection planning, the TRC Team identified seven relevant stakeholder groups for objectives I, II and III (solar). Multiple contacts within each group were then targeted for the primary data collection through interviews. The TRC Team's outreach efforts included emails and phone calls to multiple organizations within each stakeholder group to identify appropriate and willing participants for the study. The TRC Team completed 17 in-depth interviews (45-60 minutes) with two to four contacts for each stakeholder type. The TRC Team developed an interview guide to explore the study's community DER research objectives and the associated research topics, which was refined over the course of the first several interviews.

The TRC Team initiated interview data analysis by carefully coding interviewee comments to the research questions. The TRC Team then integrated comments across respondents to develop a unified landscape of community DER experience and views. The TRC Team was attentive to comments that were inconsistent among interviewees and investigated such comments by considering the interviewees' affiliations and experiences, as well as by conducting secondary research to situate the comments within a larger context. Figure 4 presents the stakeholder groups and the list of organizations that were contacted for the primary data collection.

Stakeholder Type	Organization Name
1. Developer	Clean Energy Collective
	NRG Community Solar
2. Utilities	Pacific Gas & Electric
	Southern California Edison
	San Diego Gas & Electric
	Sacramental Municipal Utility District
3. Non-utility Program Administrator	Marin Clean Energy
	Energy Trust of Oregon
	Community Solar Value Project
4. Municipal Government	City of Lancaster
	City of Davis
5. Regulator	California Public Utilities Commission
	California Energy Commission
6. Policy Expert	National Regulatory Research Institute
	National Rural Electric Cooperative Association
	Solar Energy Industries Association
	California Solar Energy Industries Association (CALSEIA)
7. National Laboratory	National Renewable Energy Laboratory
	Lawrence Berkeley National Laboratory

Figure 4: Community Solar Primary Data Collection Stakeholder Groups and Sources

The TRC Team conducted twelve interviews for objective IV (biomass), which included representatives from ten case study projects identified in California and two biomass industry experts from the project TAC.

Figure 5 presents the list of case studies and organizations interviewed for objective IV.

	Biomass Case Study and Organizations Interviewed
Case Studies	1. UC Davis CleanWorld Biodigester
	2. Kompogas San Luis Obispo
	3. Los Angeles Sanitation District
	4.East Bay Municipal Utility District
	5. Zero Waste - San Jose
	6. Point Loma Wastewater Treatment
	7. Old River Road Dairy
	8.Van Warmerdam Dairy
	9.Cabin Creek Biomass Facility Project
	10.North Fork Community Power
TAC Members	11.Sempra Gas/ SoCAlGas
	12.Lawrence Berkeley National Lab

Figure 5: Community Biomass Case Studies and Primary Data Collection Sources

5. Synthesis of Findings: Community Solar

This section provides an overview of the national and California community solar markets and has been informed by market data and excerpts from the DOE-funded Community Solar Value Project (CSVP)[9] paper "Community Solar: California's Shared Renewables at a Crossroads," a paper developed jointly with Navigant Consulting, Inc. (TRC Team member).

5.1 What is a Community Solar System?

The TRC Team recognizes that there is no consensus on a definition of a "Community Solar System." For the purpose of this project, we define a "Community Solar System" as a centralized solar generation facility that is grid connected and allows multiple customers to share the solar output from the facility. Occasionally referred to as "Shared Solar" projects, these projects typically vary in scale from 1-20 MW and pool investments from multiple subscribers to provide power and sometimes financial benefits in return (NREL, 2015).

5.2 California Community Solar

California, once considered a leader in community solar, has struggled to implement Senate Bill 43 (SB-43), the enabling legislation for community solar programs passed in 2013. This bill mandated the creation of the Green Tariff Shared Renewables (GTSR) Program. As envisioned by SB-43, the California investor-owned utilities (IOU) GTSR Program includes both a Green Tariff (GT) option component and an Enhanced Community Renewables (ECR) component.

- **Green Tariff**. Customers purchase energy from a portfolio of sources with a greater share of renewables compared to the local IOU standard mix. The IOUs procure this new renewable energy using CPUC-approved tools like those required by the California RPS. The customer pays the difference between their current generation charge and a charge that reflects the cost of procuring 50%-100% solar generation for their electric needs. For example, for PG&E, the GT premium for 2017 ranges from 1.49 to 3.34 cents per kWh, depending on customer rate class.
- **Enhanced Community Renewables**. A customer agrees to purchase a share of a local solar project directly from a solar developer in exchange for a credit from their utility for the customer's avoided generation procurement and their share of the benefit of the solar development. ECR projects are limited in size to between 500 kW and 20 MW. No price premium specifics are available for the ECR program, as projects have not been completed.

The GTSR program provides an opportunity for the three California IOUs combined to procure up to the 600 MW total program cap of new renewable energy under its two components. Figure 6 outlines the program capacity allocation for both program components across the IOUs and the program-specific reservation carveouts.

	Percentage of Total IOU Bundled Sales	TOTAL (MW)	Environmental Justice (MW)*	Davis (MW)**	Unreserved (MW)
PG&E	45.25%	272	45	20	207
SD&E	9.87%	59	10	N/A	49
SCE	44.88%	269	45	N/A	224
TOTAL	100.00%	600	100	20	480

Figure 6: Allocation of GTSR Capacity, in MW (Source: CSVP & Navigant, 2017)

[9] http://www.communitysolarvalueproject.com/

***Environmental Justice Reservation:** SB-43 requires that 100 MW of the GTSR Program be reserved for facilities that are no larger than 1 MW and are located in "the most impacted and disadvantaged communities," as identified by the California Environmental Protection Agency (CalEPA).

****City of Davis Reservation:** Section 2833(d)(3) reserves 20 MW "for the City of Davis." Decision 15-01-051 discusses the significance of this reservation.

As illustrated in Figure 7, rather than adhering to the deadlines required by SB-43, the filings, hearings, and rulings have stretched on for years. In January 2015, CPUC issued Ruling D.15-01-051, describing an implementation of SB-43 in three phases:

- Phase I: SDG&E and PG&E Green Tariffs
- Phase II: SCE Green Tariff
- Phase III: Enhanced Community Renewables

This ruling minimized the value of shared renewables and incorporated multi-part, complex tariffs that resulted in a premium of more than 3 cents per kWh for residential customers on the GT portion of the utility programs. An exact premium on ECR cannot be calculated until project bids are accepted—which has still not occurred as of August 2017.

With additional changes and clarifications clearly required, the parties began a series of Phase IV hearings to finalize details. The CPUC issued Ruling D.16-05-006 in May 2016—some 32 months after passage of SB-43—with numerous clarifications but no change in the basic structure of the complex tariffs or program requirements. The decision did increase the maximum ECR project size from 3 MW to 20 MW.

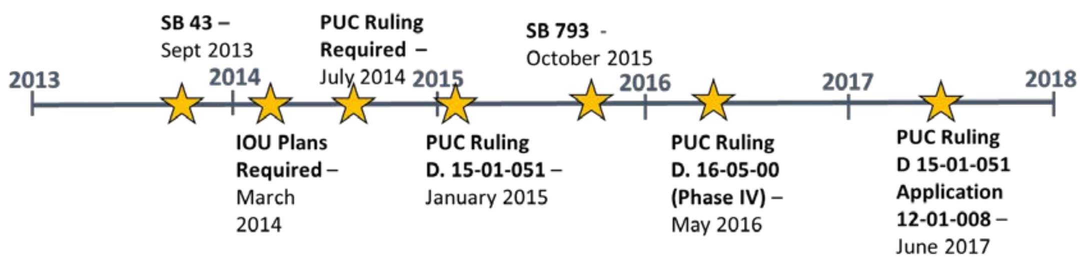

Figure 7: Shared Renewables Implementation Timeline (CSVP & Navigant, 2017)

5.2.1 ECR Program Challenges

The first request for offer (RFO) for the ECR program launched in August 2016, with awards planned for March 2017. However, no power purchase agreements (PPAs) were awarded in the first RFO under the ECR community solar program. Of the 15 bids submitted, all bids failed to meet the program eligibility criteria, with 11 bids being eliminated due to failure to submit a Phase 2 interconnection study and documentation demonstrating project site control. The second RFO is currently underway, with the market anticipating similar results in the fall of 2017.

Utility	Number of Bids Received	Number of Bids Shortlisted	Number of PPAs Awarded
PG&E	8	3	0
SDG&E	2	1	0
SCE	5	0	0
Total	15	4	0

Figure 8: ECR RFO Round 1 Results (CSVP & Navigant, 2017)

Based on conversations with leading solar developers in the market, the following barriers have emerged as the largest roadblocks to the early success of the ECR program:

- **Low and uncertain bill credit:** Unlike many successful community solar programs elsewhere, the California rules only credit customers for the wholesale generation value of the power, which is roughly one-third of the customer's electric bill, with additional program fees. When compared to community solar bill credits in other states and NEM rates in California, the current bill credit cannot compete—which developers described as the largest program barrier.
- **Demonstration of community interest:** The developer must provide documentation within 60 days of being notified of a contract award that: (1) customers have either submitted "expressions of interest" covering 51 percent of project capacity or "committed to enroll" in 30 percent of project capacity; and (2) a minimum number of customers depending on project size have subscribed to the project (e.g., minimum of 3 subscribers for 3 MW projects and 20 subscribers for 20 MW projects). Additionally, at least 50 percent and one-sixth of project load should come from residential customers. This requires developers to frontload significant customer acquisition costs prior to being notified of contract award.
- **AmLaw 100 securities opinion:** The developer must incur the cost of a securities opinion from an AmLaw 100 law firm stating the arrangement complies with securities law. After much debate, CPUC revised the requirement in June 2017; while a securities opinion is still required, it can now be from a qualified California lawyer.

5.2.2 Other Community Solar Activity in California

While no developer has built a solar project under the ECR program at any of the California IOUs, successful models for community-scale distribution sited solar have emerged in California. Such models make it clear that concerns regarding the GTSR Program are related to the basic structure and requirements of the GTSR Program and are not due to lack of IOU implementation support. The Sacramento Municipal Utilities Department (SMUD), Los Angeles Department of Water and Power (LADWP), City of Palo Alto Utilities (CPAU), and other municipals have announced new community solar programs with multi-megawatt targets, although their program tariffs are still not set.

While the Solar Shares program held steady at 1 MW for several years, SMUD expanded the program to include nearly 11 MW of additional local shared solar capacity for commercial customers. SMUD has recently announced additional solar resource procurement to support further expansion of the program in early 2018. LADWP announced its own community solar program, beginning with a 2 MW Phase I, with additional development likely following. While each municipal utility has its own positives and negatives and the possibility of delays exists in any new program expansion, these examples illustrate that nothing specific to California prevents a successful community solar program.

5.3 Community Solar and California's Zero Net Energy (ZNE) Goals

This section summarizes findings from research questions 1.3 and 3.3. It provides an understanding of the role of community solar in California's ZNE goals. It provides examples of available regulations that have enabled the use of off-site community solar projects as viable mechanisms for ZNE compliance.

In the 2013 Integrated Energy Policy Report (2013 IEPR) (CEC, 2013), the CEC adopted a definition for ZNE Code Buildings, developed in collaboration with the CPUC. This ZNE definition calls for a building to include on-site renewable energy generation that offsets the time-dependent value of the energy used in the building. In the 2015 IEPR (CEC, 2015), this definition was updated as follows:

"A ZNE Code Building is one where the value of energy produced by on-site renewable energy resources is equal to the value of the energy consumed annually by the building, at the level of a single "project" seeking development entitlements and building code permits, measured using the California Energy Commission's Time Dependent Valuation metric. A ZNE Code Building meets an Energy Use Intensity value designated in the Building Energy Efficiency Standards by building type and climate zone that reflect best practices for highly efficient buildings."

Community Solar and ZNE Expectations

Stakeholders interviewed identified the following expectations for community solar and ZNE:

- Community solar assets would need to meet the criteria met by on-site systems deployed for ZNE construction as: *dedicated* to the building; *durable*; providing *equivalent benefit* at the same time as a site-based asset would; has *quantifiable* performance that is at least as great as the site-based alternative; is *verifiable* (both its existence and performance); and is *cost-effective (CEC Interview Respondent)*.
- Community solar has the potential to constitute an alternative to site-based renewables, but none were aware of community solar being currently used in the service of ZNE buildings/communities *(Interview Respondents among multiple stakeholder types*).

The 2013 IEPR also highlighted some issues that needed to be addressed to meet ZNE goals. Those issues included:

- Identifying pathways of compliance for buildings where onsite renewables are not feasible.
- Developing viable accounting and enforcement mechanisms for offsite renewable projects used to meet ZNE requirements.

The 2015 IEPR specifies that for newly constructed low-rise homes that cannot accommodate onsite renewables, alternative compliance pathways that enable such buildings to meet ZNE Code Building requirements must be developed. The ZNE Code Building definition anticipates considering "development entitlements" for off-site renewables, as a potential option for builders and developers. The ZNE definition clearly allows community solar as a possibility; however, approaches need to be identified that would make it administratively workable and cost-effective. Any option that relies on off-site renewable resources must allow for building department verification to ensure that the identified resources exist, that they are the correct size for offsetting the energy use of the buildings they are assigned to, and that the output of these resources is not already assigned to other approved developments.

As part of the 2019 Title 24 part 6 rule-making process, the CEC presented options to have offsite solar meet the criteria set for site-based renewable systems deployed for ZNE new construction (CEC, 2017). These criteria include that the resource is: *dedicated* to the house or building; *durable;* providing the *equivalent benefit* at the same time as a site-based asset would; *quantifiably* performing at a level that is at least as great as the site-based alternative; *verifiable* (both its existence and performance), and *cost-effective*. The CEC has authority, through the establishment of building codes, over each individual structure; it currently has no authority to associate a community solar asset with a newly constructed development and, in doing so, make the development ZNE-compliant. To address this, the CEC is considering providing a ‘compliance option’ for community solar instead of specifically requiring community solar. A compliance option is a voluntary option that a builder can choose to comply with the code. The compliance option may take one of the following four forms:

- Bundle the community solar with the house or building at time of sale, included in any mortgage. This would be done by locating the solar system at another location within the same subdivision. Solar panels would be dedicated to a home and direct current (DC) connected to the inverter installed at the home. Although the solar purchase could be optional at the time of building purchase, this model would require customers to purchase their share of the solar asset upfront and continue to have that power source as long as they owned the real estate.
- Allow community solar systems authorized through the GTSR to meet the ZNE code mandates. The utility or a third party would thus own the community solar system but the customer would be credited for the solar energy produced.
- Allow the builder of the subdivision to install a community solar system at another location outside of the subdivision and then administer savings/solar allocation to the homeowner. In this instance, the solar allocation would “ride” with the house. Another option would be to establish a legal entity, separate from the developer, for the newly constructed community to own and operate the system; such as an LLC or bankruptcy remote company. Under this model, a solar developer or possibly an EPC (Engineering, Procurement, and Construction) firm would construct the system. In this form, the community served by the asset would have non-interest shares in the LLC because homeowners and most businesses would be non-accredited investors and thus cannot literally own a portion of the asset. The non-interest shares would not be liquid but would be transferred at the time of home purchase.
- Create Local Government Community Facilities District (CFD) to own and administer a community solar option for all new residential developments within a given local community. This option would work similar to other local investments funded through Mello-Roos style infrastructure bonds repaid through property taxes.

Some jurisdictions have already adopted solar or ZNE-related ordinances with compliance options, for which community solar might be a viable mechanism for achieving those ZNE mandates. For example, the City of Lancaster has a goal to be a ZNE city and its Ordinance No 1020 allows builders to meet the solar requirement by paying a solar mitigation fee based on the square footage of the living space of each home that is built.

The City of Berkeley’s climate action plan (2009) incorporates solar energy as a means of meeting carbon reduction, energy independence and security, workforce development, and improved building energy efficiency goals. The City aims to eliminate 11,600 metric tons of carbon dioxide equivalent (MtCO2e) per year by 2020 through decentralized solar electric installations on residential and nonresidential buildings. The City is also offering numerous services to encourage decentralized solar installations that include innovative financing programs, personalized energy consultations, and an online solar map that estimates the solar energy potential for Berkeley homes and businesses.

5.4 Nationwide Community Solar Landscape

This section summarizes findings from research questions 1.1 and 1.2. It provides an understanding of the available regulatory mechanisms for enabling the community solar market across the country and in California.

According to the Solar Energy Industries Association (SEIA), the City of Ellensburg, WA project was the first community solar project in the nation in 2006. Since then, the U.S. has experienced rapid community solar growth. As of early 2017, Navigant identified that 40 states had at least one community solar project online. Driven by state policy, four states -- California, Colorado, Massachusetts and Minnesota -- are expected to install the majority of community solar over the next two years (SEIA, 2017). At least 18 states plus D.C. have enacted community solar legislation and 40 states have at least one active community solar project[10].

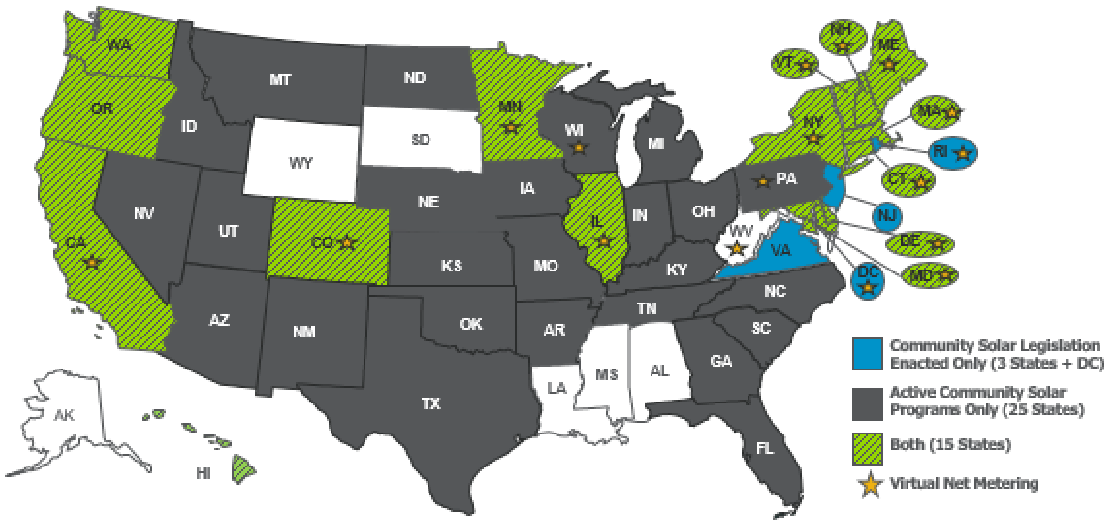

Figure 9: Community Solar Regulatory Map (Navigant, 2017)

5.4.1 Regulations at the State Level

Community solar has gained a place in the U.S. solar market and its rapid growth shows no signs of slowing down. Active community solar legislation varies from state to state, but often includes some combination of the following:

- Program and project capacity caps
- Value credited for a kWh of electricity produced from a community solar project
- Treatment of renewable energy credits
- Program participation rules
- Project ownership models (utility owned vs. third-party developer owned)

Figure 10 highlights legislation from some of the most active or promising community solar state markets to date.[11]

[10] Navigant Community Solar Program Tracking Database, 2017 (United States)

[11] Navigant Community Solar Tracking Database, 2017 (United States)

State	Legislation
California	• Senate Bill 43, Chapter 413**:** Green Tariff Shared Renewables Program established a future clean electricity rate for all customers served by California's IOUs. • Program size of 600 MW across California's IOUs
Colorado	• House Bill 1342: Community Solar Gardens policy passed in 2010. • House Bill 1284: Passed in 2015 to expand participation in Solar Gardens. • Value of Solar Rate: Community solar credits are delivered to participants at a value of solar rate, rather than at the full retail rate.
Massachusetts	• Senate Bill 2768: Virtual net metering from the Green Communities Act between any customers (2 MW limit). • Senate Bill 2395: Neighborhood Net Metering is seldom used because SB 2768 is so attractive.
Minnesota	• HF 729**:** Solar Energy Jobs Act • Xcel submitted program plan in 2013. Participants credited at retail rate and later at a value of solar rate. Program size limited to 1 MW per project and each project must have a minimum of 5 participants. • Value of Solar Rate: Community solar credits are delivered to participants at a value of solar rate, rather than at the full retail rate.
Hawaii	• Senate Bill 1050/ House Bill 484**:** Hawaii's shared renewables bill was signed into law in June 2015 requiring each electric utility to file a proposed community-based renewable energy tariff with the PUC.
New York	• PSC Order Establishing a Community DG Program was passed in July 2015.
Maryland	• House Bill 1087/ Senate Bill 48**:** Passed in 2015 establishing a 3-year pilot program for community solar energy generating systems under the authority of the Public Service Commission. • A 3-year pilot program with a 200 MW cap and 60 MW designated for moderate and low-income houses was approved for Maryland in June, 2016.
Illinois	• Public Act 99-0906: Future Energy Jobs Act took effect on June 1, 2017 and established the Adjustable Block program, which requires 400 MW of community solar to be built in Illinois by 2030. The Act also contains a Low-Income Community Solar Project Initiative.

Figure 10: Leading Community Solar State Legislation (Navigant, 2017)

Research estimates show that 49% of households and 48% of businesses in the U.S. are currently unable to host a rooftop solar system (NREL, 2015). A supportive regulatory environment at the federal, state and local level can pursue community solar growth by expanding the potential customer base of homes and businesses. In 2015, NREL stated that by opening the market to these customers, shared solar could represent 32%–49% of the distributed solar market in 2020, thereby leading to growing cumulative solar deployment growth from 2015–2020 of 5.5–11.0 GW, and representing $8.2–$16.3 billion of cumulative investment (NREL, 2015). Although some subsequent reports claim NREL's numbers are bullish, potential for the community solar market remains promising if supported by state policy and regulation.

5.4.2 Land Use Planning and Permitting Regulations at Municipal/County Level

While national and state regulations apply across jurisdictions, cities and counties are uniquely positioned to support and strengthen the growth of community solar energy since these geographic locations have the highest concentration of buildings and building energy consumption. Key roles that cities and counties can play in this market include:

- Community-scale solar systems can potentially have different impacts on land use than rooftop systems and may give rise to public concerns over these impacts. Many communities restrict larger community scale solar systems to rural, industrial, agricultural, commercial zoning districts, or as special use conditions.
- Local governments may have specific development standards that include minimum lot size, height limitations, setbacks from property lines or neighboring structures, screening from adjacent public rights-of-way, fencing, warning sites, underground installation of on-site electrical interconnections and power lines, etc.
- Community solar project permit documentation might include a detailed plot plan, as well as an agreement with a utility for facility interconnection.
- Some ordinances include stormwater management considerations, and in more rural communities or areas that abut public land, an environmental analysis for potential impacts on wildlife and vegetation may be required.
- Decommissioning of non-operational facilities is typically required, with some communities requiring restoration of the site to its previous condition, especially for land formerly used for agriculture (APA, 2013).

Planners have important roles to play in making sure their communities' plans and Land use regulations allow and encourage a clean, safe energy source. Cities and counties sometimes take the approach of amending local zoning to promote solar development. The California County Planning Director's Association (CCPDA) has made available a Solar PV Model Ordinance[12] which provides a streamlined regulatory climate for the installation of solar energy facilities, while protecting important farmland and sensitive habitat. Figure 11 below shows some existing examples of modifications of land use planning and zoning ordinances; including some examples from California where community solar projects are specifically identified in zoning ordinances.

JURISDICTION	LEGISLATION
City of Erie, Pennsylvania	• Ordinance No. 4-2010: Urban Solar Farm ordinance provides for urban solar farms as conditional uses in manufacturing districts in accordance with specified regulations. Includes decommissioning provision.
County of Granville, North Carolina	• Code of Ordinances. Chapter 32, Land Development Code: Accessory-use solar energy systems must meet district setback and height requirements. Detailed standards provided for non-residential rooftop and ground-mounted systems.

[12] http://www.ccpda.org/en/model-sef-ordinance/145-ccpda-solar-energy-facility-permit-guidelines-approved-2012-02-03

JURISDICTION	LEGISLATION
City of San Antonio, Texas	• Unified Development Code. Article III, Zoning; Division 7, Supplemental Use Regulations: Provides detailed standards for fixed-panel photovoltaic solar farms, including site development standards, submittal requirements for solar farm building permits, and required compliance with other regulations.
County of San Diego, California	• The San Diego County Zoning Ordinance differentiates solar energy systems into two categories: Onsite Use and Offsite Use. Onsite Use is permitted in any zone and is recognized by the Code as an Accessory Use. Offsite Use systems 10 acres and less require an Administrative Permit, while those greater than 10 acres require a Major Use Permit. Prior to issuing County approval, the Code includes a requirement to provide financial surety for removal. The County created the ordinance to implement the County's Energy Element of the General Plan.
County of Santa Clara, California	• Ordinance No. NS-1200.331: This Santa Clara County Ordinance Code applies to solar energy systems that do not serve on-site load. The Ordinance differentiates systems as minor and major. Minor systems are those 8 acres and less and Major systems are those greater than 8 acres. The ordinance establishes restrictions for solar energy systems installed on large-scale agriculture by the general plan, and allows this use on only those medium-scale agricultural lands that are deemed to be of marginal quality for farming purposes.
City of Irvine, California	• Ordinance No. 16-06: The City of Irvine's Zoning Ordinance allows for the installation of solar energy systems on all parcels in the City. The Ordinance differentiates installation on two types of property. In residential zones, solar energy systems are permitted as ground-mounted and roof-mounted. In commercial/ industrial/ institutional/ multi-use/ office zones, solar energy systems are permitted as covered parking systems and roof mounted systems.
County of Iron, Utah	• County Code 2010 ordinance provides regulations and design standards for both concentrated thermal and PV solar power plants. Includes permit requirements and detailed list of provisions for conditional use permit review.
County of Madera, California	• Ordinance No. 525NN describes solar farms permitted as conditional use subject to standards intended to address glare and excessive water use.
Township of Straban, Pennsylvania	• Ordinance 2010-02: Describes detailed development standards for "solar electric facility" use as a by-right use in residential rural areas.

Figure 11: Permitting and Zoning Ordinances for Large-Scale Solar Systems (APA, 2011)

5.5 Community Solar Ownership Models

This section summarizes findings from research questions 2.6, 2.7, 2.8 and 2.9. It provides an understanding of the available ownership models, contractual agreements and issues of insurance and securities regulations. The following section on Ownership Models includes excerpts directly from the Community Solar Value Project paper, "Community Solar Project Ownership Structures and Financing" (CSVP & Navigant, 2015).

Although many different business models are potentially useful for community solar, essentially two broadly defined generic models have emerged. The Community Solar Value Project categorizes them as follows:

- *Utility Led*: The utility-led model offers the utility the greatest leeway for strategic customization and clear utility branding, which may benefit customer acquisition and retention. In the generic utility led model, the participating customer pays the utility a monthly fee or rate for community solar in exchange for a bill credit. The utility develops the customer offer and implementation details, and it procures the community-solar resource. Procurement may involve development and direct ownership of the project. Alternatively, it may involve a PPA with a third-party developer, with or without an eventual utility "flip" or buyout. Often, the question of "ownership versus PPA" is dictated by state policies, including normalization rules, or by the tax status of the utility. As more IOUs begin to launch community solar programs and as programs grow, the market is expected to tilt toward a utility-led model. Due to the market shift toward this generic model, developers have responded with more customized service offerings (CSVP & Navigant, 2016).

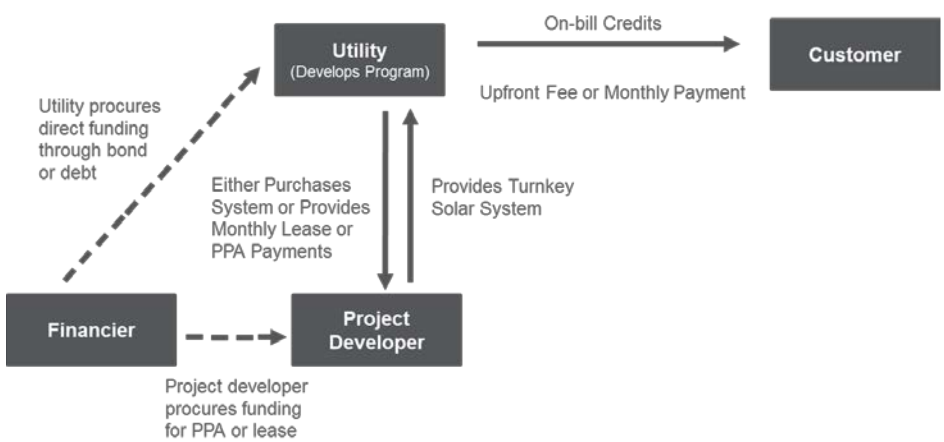

Figure 12: Utility Led Community Solar Program (CSVP & Navigant, 2016)

- *Third-Party Led*: The third-party model allows the utility to roll out a program relatively quickly and to shift many program risks, including project development and customer acquisition risks, to a third-party developer. In this model, the participating customer pays the third-party an upfront or monthly fee in exchange for a bill credit from the utility. The most typical utility-outsourced model is a full turnkey program. This model has proven to be very popular with smaller utilities, but less so with larger and investor-owned utilities (IOUs). Typically, the utility does not own the solar asset. However, it is not uncommon for a PPA structures to allow the utility to have step-in rights, i.e. the right of first refusal to buy out a project or the right to take ownership at the end of the term of the contract when the solar asset is fully depreciated. In this way, the out-sourced model can deliver long-term utility value.

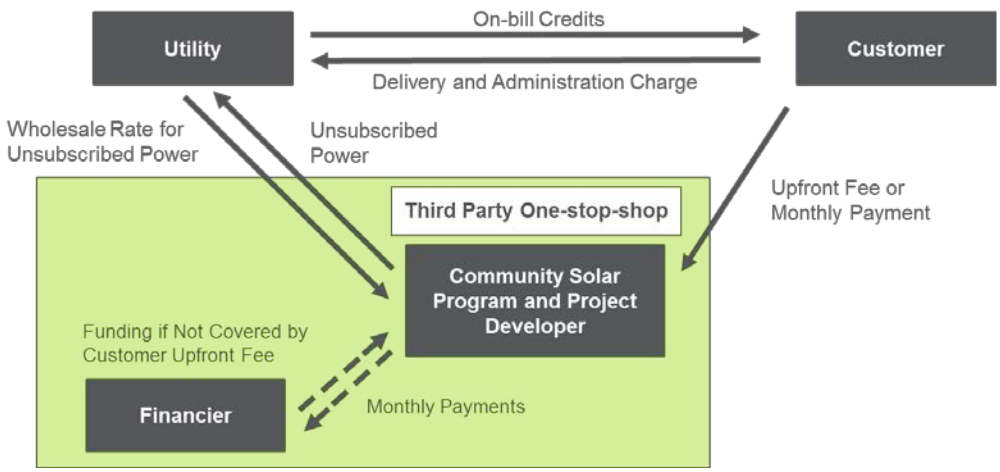

Figure 13: Third-Party Led Community Solar Program Model (CSVP & Navigant, 2016)

Within these program models, four main strategies for customers to participate and invest in community solar have emerged (Konkle, 2013):

1. ***Buy Solar Power**:* In this business model, customers pay a specified price to purchase solar power on a $/kWh rate or $/kW monthly basis from a community solar project. The PV prices are typically fixed for a period of time, up to 20 years. Sacramento Municipal Utility District (SMUD) Solar Shares Program[13] is an example of this type of model in California, enabling SMUD residential ratepayers to pay a monthly fee to secure PV production for the equivalent of 1-4.0 kW system from SMUD's existing 1.0 MW solar farm. This model offers the following advantages and disadvantages for the individual stakeholders:

    - *Utilities and/or Third-Party Suppliers*: The suppliers incur all project capital costs, operational costs, program risks, and the management of a continuous stream of buyers entering and exiting the program over the project lifetime. The suppliers maintain ownership and control over all project assets and take advantage of all financial benefits that may include tax benefits, renewable energy credits (RECs), sales, etc. The suppliers also have flexibility in accessing multiple PV generation sources and are in complete control of the scale of the project and program.

    - *Customers:* This model allows customers the convenience of accessing solar power with no out-of-pocket costs and minimal risks, and offers the flexibility of entering and exiting the program throughout the operation of the project. Due to this flexibility and minimal risk, this has emerged as the most popular business model in the last couple of years.

2. **Lease Solar Panels**: In this model, customers can lease a specific number of panels from utilities or third-party suppliers for a specific period of time (often 20 years or more). Customers receive a pro-rata production credit from their leased panels on their energy bills. If the power produced by a lessee's panels exceeds actual energy usage, the customer receives a credit on their bills. This model offers the following advantages and disadvantages for individual stakeholders:

    - *Utilities and/or Third-Party Suppliers:* The suppliers must bear all project capital and operational costs and risks but have the flexibility and control over the asset, location, and portion of the lease (e.g. ½

[13] https://www.smud.org/en/residential/environment/solarshares.htm

panel). Panel leasing can offset much of the up-front cost of the project and suppliers typically receive and sell all RECs.

- *Customers:* Customers do not have any liabilities and do not pay for maintenance, equipment replacement fees, or project insurance, as these are the responsibility of the owner-utility or third party. Customers can hedge against the base energy cost and panels can be leased at a one-time fixed cost for long periods of time. Lessees typically have a positive payback; however, in some programs, customers may have difficulty re-selling leases if they have to exit before the contract period is done.

3. **Purchase Solar Panels:** In this model, the customer purchases one or more solar panels from the community solar project. This is a true ownership program, not a lease, which often results in a higher financial payback for the participants. The solar power each panel generates is credited monthly to the customers' utility bills for the warranted life of the system, which is usually 20-25 years. This model offers the following advantages and disadvantages for the individual stakeholders:

    - *Utilities and/or Third-Party Suppliers:* Panel purchasing offsets the up-front capital costs of the project for suppliers and can generate positive cash flow if they chose to pre-sell a portion of the panels before installation. The suppliers are responsible for financing, owning, managing, maintaining and taking project risks. They also typically receive all tax benefits (as long as they technically own the panel for the first five years) and in some cases receive project RECs for the project. The suppliers might have higher SEC, tax, & consumer protection scrutiny and must adequately address complicated laws.

    - *Customers:* Purchase the solar panels individually for a one-time cost, offsetting escalating costs for comparable amounts of fossil-fuel derived power for the life of the project. Once purchased, the customer has no additional costs for repair, replacement or maintenance, and the customer has no liability or risks associated with installing the project on one's property. This option may exceed the financial reach for some customers as the panels must be purchased up front and the customers may have difficulty re-selling the panels.

4. **Invest in a Solar Project:** In this model, customers come together as members of a limited liability company (LLC) to co-invest in a specific solar project. The members form an LLC, and through this Special Purpose Entity (SPE), they purchase, install, manage and maintain the PV system. The PV system is typically located "behind the meter" at a host site, and the host agrees to pay the LLC a specific rate for the solar power generated. The LLC usually keeps and sells Renewable Energy Credits (RECs) generated by the project, and the LLC members are compensated for their investment through profit distributions and tax credits, which can be transferred directly to members as equity payments and/or tax credits, or can be monetized through interest payments to investors. This model offers the following advantages and disadvantages for the individual stakeholders:

    - *LLC Investors:* This model may offer an attractive return on investment (ROI), with earnings from tax benefits, pro-rata portions of net LLC income and solar renewable energy credits (SRECs) sales, especially in locations with higher energy costs and/or high SREC prices. The LLC maintains control over the solar asset through the life of the project but also bears all financial risk such as relevant project legal, capital, operational, insurance, and other costs. The LLC is an investment vehicle that must adhere to all appropriate federal and state securities requirements, which can be expensive to set up and complicated to manage.

    - *Host Sites:* The host must make a long-term commitment to provide a stable site for the solar project. The LLC can provide solar power to the host at a known price for the life of the project, and the host site also benefits by not being responsible for any ongoing O&M fees or project liabilities. Opportunities may exist for individuals affiliated with the host to invest in the project, purchase the solar system in the future, or have the panels removed after the project period.

Additional Ownership Model Considerations

Community Solar Contract Terms

The contract term for community solar programs can vary considerably depending on the project ownership model. Utilities offer short and flexible contracts that allow customers the option to subscribe for longer term limits such as 10 years, 20-25 years, or the life of the system. When offered by third-party developers, the term lengths are longer and less flexible (20-25 years) to enable the developer to meet its desired return on investment (NREL, 2010). According to our interview research findings, developers commonly require long-term contracts for at least 50% of the output to proceed with the project. Developers can also offer some variation by customer type, with commercial sector subscribers possibly having longer agreements than residential subscribers. Long-term contracts typically have provisions governing the transfer (via some mechanism, such as selling or reassigning) of the subscription.

Recent consumer preference research shows that consumers prefer shorter contract terms and want flexibility in their ability of entering and exiting the programs. A Pacific Consulting Group (PCG) program design study revealed that respondents preferred a month-to-month contract over longer-term contracts that range from five to ten years.[14] Other studies (Shelton Group & SEPA, 2016) indicate that consumers preferred contract terms similar to a car lease – short, with a low monthly fee. Five-year terms (29.5%) and ten-year terms (20.3%) were most popular. Customers are also looking for flexibility in taking their subscription with them if they move within a utility's service territory.

Our Team's interview research inquiry into potential breach of contract issues and potential concerns of consumers reverting to the utility tariffs suggest that the industry is not concerned about this issue. Our respondents across multiple stakeholder types expressed the view that community solar policy does not need to address the potential for developer breach of contract; instead, contract terms need to clearly address the issue. Stakeholders advocated for contracts that provide full written disclosure for all parties in a manner that is clear and transparent. For example, the Oregon Public Utilities Commission is developing community solar regulations that are likely to require commission approval of community solar contracts prior to a developer soliciting subscribers. Below are some options available to developers and utilities regarding contract options[15]:

- Rocky Mountain Power's Shine Program allows customers to join or leave the program whenever they want with no associated cost.
- Utilities and developers can require a security deposit where customers are charged a set fee upfront covering a specific subscription term. If they leave prior to their subscription term, the consumers are charged a prorated amount for their deposit.
- Customers are charged exist-fees or a penalty for an early exit from the program.
- Developers and utilities can dis-incentivize consumers from leaving the program by making it harder to allow them to access the program- for example allowing a specified waiting period for resubscription after an untimely program exit (for example 12-month restriction in California's Green Tariff program).

[14] https://www.greentechmedia.com/articles/read/community-solar-programs-can-reach-millions-of-people-if-utilities-design-a

[15] https://www.greentechmedia.com/articles/read/community-solar-programs-can-reach-millions-of-people-if-utilities-design-a

Securities Considerations

There has been considerable discussion around whether community solar projects are considered "securities" under the Securities Exchange Commission (SEC) requirements and need to abide by the SEC requirements for registration and disclosure of projects. The design of ownership and customer participation in community solar projects must comply with securities regulations. This requires careful consideration of the benefit a customer-participant receives in exchange for a financial contribution to the project and how the project is marketed. For example, customer participants may buy ownership stakes in the solar system itself or just the rights to certain benefits from the energy produced (such as credit on their electric bills, RECs, or access to a special electric rate). To avoid any appearance of selling securities, the Sacramento Municipal Utility District (SMUD) chose not to sell actual ownership of panels, but instead to credit customers for an estimated monthly output of solar electricity, specified in advance of enrollment (NREL, 2010).

For the GTSR, in May 2016, the CPUC through D.15-01-051 identified that subscriber participation in an ECR contract could present securities litigation risk and required the ECR developer to "include a securities opinion from an AmLaw 100 law firm stating that the arrangement complies with securities law and that the IOU and its ratepayers are not at risk for securities claims associated with the project."[16]

In July 2017, the CPUC adopted D.17-07-007, which grants the joint Petition for Modification of D.15-01-051, which replaces the AmLaw 100 Securities Option Requirement with a three-part requirement which requires that securities opinions come from a lawyer or firm with: 1) eight years of experience in securities law; 2) currently licensed by the California Bar; and 3) carry a minimum of $10 million in professional liability coverage. These requirements were based on a joint parties' workshop hosted by the CPUC on October 13, 2016.

Insurance Considerations

Community solar projects are susceptible to the following risks: physical damage, income disruption, design and management liability, malpractice and more. There is also risk of product and program underperformance for community solar projects, which can put investors at great financial risk. The complicated ownership and financing models associated with community solar projects create additional risk for the industry, which are not typically covered by traditional insurance companies. The risk and uncertainties about attaining projected performance can have a particularly adverse effect on a project's market acceptance or viability.

Typically, the insurance costs of a community solar project are borne by lenders, financiers and/or developers. These costs have a bearing on the bottom line of the project and are included in the overall pricing models for consumers. As the solar market continues to grow, more insurance companies are entering the solar space with the hopes of penetrating the market through competitive coverage and terms. Some of the insurance coverage models cover product warranties, damage, theft, and other conventional risks. Energy Performance Insurance is also emerging as an innovative product to protect private lenders, public finance authorities, third-party investors, bondholders or project owners from underachievement of predicted technology performance or project output. From a project developer, Original Equipment Manufacturer (OEM) financier or equity investor, this insurance provides the safety net to assure their financial success and restores the project economics in the event of any product or system failure.[17] This is an evolving area and industry stakeholders such as the Solar Energy Industries Association (SEIA) and the Smart Electric Power Alliance (SEPA), American Board of Certified Energy Practitioners (NABCEP) and others are working on setting standards and guidelines.

[16] D.15-01-051 at 71.

[17] https://www.solarpowerworldonline.com/2013/06/how-will-solar-insurance-keep-up-with-new-financing-models/

5.6 Community Solar Compensation Mechanisms and Project Incentives

This section summarizes findings from research questions 2.2, 2.3 and 3.2. These questions cover issues related to accounting for community solar output, community solar project incentives such as tax credits, depreciation, renewable energy credits and financing mechanisms such as loans. Issues summarized below are critical to the overall financial viability of a community solar project and for enabling the overall business case for future community solar development.

Although the cost of solar energy systems is expected to continue to decrease over the next decade, a solar system remains a large investment. While taxpayer and ratepayer-funded incentives have played a significant role in advancing the California solar market to date, other compensation mechanisms are needed for sustained community solar market growth. For an owner/operator, the community solar system must offer financial benefits that outweigh the system costs. According to a survey conducted by The Shelton Group and SEPA, the reduction of upfront capital and lower maintenance costs are the primary reasons people prefer community solar over traditional rooftop solar (Shelton Group and SEPA, 2016). For the customer, cost savings are one of the largest drivers of community solar adoption. As described below, several community solar compensation methods exist.

5.6.1 Community Solar Compensation Mechanisms

Depending on state policy or utility community solar program specifications, community solar programs often use one of the following compensation mechanisms.

- *Virtual Net Metering (VNM) Rate*: Solar PV production is virtually credited to the customer's bill at a $/kWh rate equivalent to the full retail rate. In some cases, the customer purchases PV system panels and receives compensation on a monthly basis for the panels generation (kWh). Full retail rates are often the rate that customers receive for installing behind the meter rooftop solar PV under traditional Net Energy Metering (NEM) programs (e.g. Massachusetts).
- *Value of Solar (VOS) Rate*: Some states (e.g. Colorado, Minnesota, Maryland) have developed VOS rates for crediting community solar electric production. VOS rates are intended to compensate for real value provided by the solar installations to the electric system and are usually lower than full retail rates but higher than wholesale rates, accounting for a combination of value streams (e.g. energy, capacity, transmission, distribution, environmental, social, etc.) (NREL, 2015).
- *Wholesale Rate:* Community solar programs in other states focus on ratepayer indifference (e.g. California IOUs) and only credit customers for the wholesale generation value of the power, which in California is about one-third of the customer's electric bill.

5.6.2 Community Solar Incentives

Solar incentives play a role in driving down the cost of solar, enabling utilities and third parties to develop community solar programs that in many territories either offer customers savings on their utility bill or require customers to pay a small premium.

Federal Investment Tax Credit (ITC)

The federal Investment tax credits (ITC) is among the most valuable incentives available for solar energy and allows owners of solar systems to take a one-time tax credit equivalent to 30% of qualified installed costs. The system is eligible in the first year of operation either under Section 25D (residential) or under Section 48 (commercial) of the tax code. Under the ITC, the owner of the solar system for tax purposes can be different from the owner of the host property. As a result, the use of a third party financing has emerged as a leading trend in the solar industry.

On December 18th, 2015, legislation extending the ITC was signed into law. It extends the 30% residential and commercial credits through the end of 2019 and then drops the credit to 26% in 2020, and 22% in 2021 before dropping permanently to 10% for commercial projects and 0% for residential projects. The ITC extension will spur an estimated $132 billion in additional investment in the U.S. economy between 2016 and 2020, roughly $40 billion more than would have been invested without the ITC extension.[18]

The establishment of the ITC led to the development of a tax equity market and since 2007, most solar development has been financed partly by tax equity.[19] Typical tax equity investors include major banks (e.g. Wells Fargo), financial institutions (e.g. Goldman, Sachs), and corporations (e.g. Google) that have large tax liabilities.

Community Solar Compensation Mechanisms:

Stakeholders interviewed observed the following for community solar monetization mechanisms:

Most respondents expressed the view that customers need to have the flexibility to enter and exit from community solar projects.

Respondents identified other potential value streams including the environmental benefits of reduced emissions of greenhouse gases (GHG) and criteria air pollutants.

Developmental benefits of community solar that can be monetized, such as shade provided by canopies constructed to hold solar panels in parking lots, community outdoor spaces, schools, hospitals, car dealerships, etc. *(Interview respondents among multiple stakeholder types*).

Currently, there is no clear guidance under the ITC whether it is applicable for community or shared solar or not. This tax incentive was developed with either individually owned PV installations or commercial-scale solar projects in mind. Community-scale projects don't fit squarely into either category, which makes it challenging to design projects that can make use of either the residential or commercial tax credits (NREL, 2010). For example, the residential Renewable Energy Tax Credit is not available to community solar projects because it only applies to taxpayers who install a solar system on their own residence.

In 2013, the IRS issued Notice 2013-70[20] which signaled that Section 25D eligibility may extend to a single taxpayer who owned off-site solar panels, owns the electricity transmitted by the solar panels to the utility grid until drawn from the grid at his residence; and who does not generate significantly more electricity than is consumed by the taxpayer at her or his residence. While this makes Section 25D eligible for a single taxpayer in such community solar scenario, it is not clear whether it can be more widely applied to a situation involving multiple taxpayers entering into an offsite shared solar arrangement with different utility agreement terms.

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[18] http://www.seia.org/research-resources/impacts-solar-investment-tax-credit-extension

[19] SolomonEnergy, *Wat is Tax Equity Financing?* http://www.solomonenergy.com/blog/wp-content/uploads/2015/08/2015-08-14-What-is-Tax-Equity-Financing.pdf

[20] https://www.irs.gov/irb/2013-47_IRB/ar09.html

More recently, in September 2015, the IRS issued a Private Letter Ruling[21] awarding a taxpayer in Vermont the 30% ITC on his off-site community solar investment. While technically a private letter ruling only applies to its intended recipient, it is often interpreted as a precedent for how the IRS would rule in similar circumstances. According to the letter, a taxpayer can use the 25D credits if the solar power generated by their share of the community solar project does not exceed their residential needs, the solar power generated is provided to the taxpayer's local utility, and the utility provides the taxpayer with a credit for their share of the energy produced by the entire community solar project. There is no federal legislation enacted to date that explicitly allows individuals to claim the ITC for their share of a community solar project.

Another method for leveraging the 30% federal Investment Tax Credit (ITC) on a community solar project is to have the developer of the project retain ownership of the panels. The leading community solar developer utilizes this business model by retaining ownership until the 30% solar ITC savings are maximized, driving down the project cost.[22] For example, Clean Energy Collective's South Carolina Electric & Gas's Roofless Solar program capitalizes on the full federal ITC by maintaining ownership of the panels for the first six years of the system. After the six-year mark, community solar customers have the option to purchase the panels. The savings from the federal ITC are transferred back to the customers who purchase the panels at a reduced price in the year six.[23]

Modified Accelerated Cost Recovery System (MACRS)

The federal tax policy allows businesses but not individuals to depreciate their solar project investments on an accelerated basis under the Modified Accelerated Cost Recovery System (MACRS). Businesses can record this reduction in asset value as an expense over a set period of time, typically five years, and offset their income with losses generated by accelerated depreciation deductions increasing the financial viability of the project. The MACRS provides 50% bonus depreciation for all projects and equipment placed in service before January 1, 2018. The available bonus drops to 40% for equipment placed in service in 2018; and to 30% for 2019 projects[24]

Renewable Energy Credits (REC)

The Renewable Energy Credit (REC), defined as the renewable energy attributes of 1 MWh of renewable electricity generated and delivered to the grid, is a concept originally developed for three main reasons. These include federal agency, business, and industry interest in purchasing green power; state-sanctioned accounting to meet renewable energy mandates; and added economic benefits in negotiating power purchase agreements to cover renewable energy project costs (Romano, 2016).

Today, all claims of using renewable electricity depend on the associated RECs, which are a credible way to buy and sell renewable electricity because they can be uniquely numbered and tracked. The electricity associated with a REC may be kept bundled with the REC or sold separately. If it is kept bundled, then it is called renewable (or green) electricity. If the electricity is split from the REC, it is considered standard or null energy.

Community solar programs across the country are currently struggling with how to market a community solar program if the project share includes something less than a REC-bundled kilowatt-hour. If the project unbundles

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[21] https://www.irs.gov/pub/irs-wd/201536017.pdf

[22] http://www.cleanenergyco.com/utilities.html

[23] http://sceg.rooflesssolar.com/faqs

[24] https://energy.gov/savings/modified-accelerated-cost-recovery-system-macrs

the RECs, the Community Solar program cannot legitimately claim that the project delivers renewable energy. The Center for Resource Solutions has developed best practices for marketing community solar programs for developers.[25] The Federal Trade Commission, the Interstate Renewable Energy Council's Consumer Bill of Rights, and Solar Energy Industry Associations' Business Code all place the burden of REC education on developers. REC ownership and the environmental benefits of the purchase should be clear and accurate in all marketing and should be conveyed within the contract.

In California, the CPUC directed the IOUs to seek Green-e Energy certification for each of the two programs under the Green Tariff Shared Renewables Program.[26] A Green-e Energy certified product provides the assurance that the solar product purchased meets the highest environmental and consumer-protection standards, including requirements that the renewable energy not be used by the utility to meet other renewable energy requirements set by the state.[27] Thus, the Green-e Energy certification essentially requires that consumers be offered a fully bundled energy product, including the RECs. Developers participating in this program are required to follow industry best practices in terms of providing clear and accurate marketing regarding renewable energy claims.

For ZNE buildings and communities, the issue of whether RECs are sold or retired is very important. Currently, there is no specific policy guidance but if the developer of the community solar system sells the RECs to meet RPS requirements or generate revenue for the project, the output from that solar system should no longer be considered a local "renewable" resource for the consumers using that energy. Thus, for a community solar system to qualify for ZNE buildings, the developer would need to retire the RECs on behalf of the customer. Further, the developer may not count the output of the community solar towards any other purposes such as the RPS. This issue needs to be further addressed through a more detailed analysis in future phases of this project.

5.6.3 Community Solar Financing Mechanisms

A number of community solar project finance structures exist, including bond or debt financing; third-party owned Power Purchase Agreements (PPA) or Solar Service Agreements (SSA); pre-paid PPA/SSA; and lease and a project flip structure. These finance structures are well-described in the Community Solar Value Project paper "Community Solar Project Ownership Structures and Financing" (CSVP & Navigant, 2015). In addition to these structures, Property Accessed Clean Energy (PACE) loans are a possible financing mechanism to explore in the future.

Property Accessed Clean Energy (PACE) Loans

The Property Assessed Clean Energy (PACE) is a financing mechanism that enables low-cost, long-term funding for energy efficiency, renewable energy and water conservation projects. PACE financing is repaid as an assessment on the property's regular tax bill, and is processed the same way as other local public benefit assessments (e.g. sidewalks, sewers) have been for decades. Depending on local legislation, PACE can be used for commercial, nonprofit and residential properties. PACE is a national initiative, but programs are established

[25] https://resource-solutions.org/wp-content/uploads/2016/10/091216-SPI-Handout.pdf

[26] http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M146/K250/146250314.pdf

[27] https://www.green-e.org/programs/energy/ca-ecr-customers

locally and tailored to meet regional market needs. Local governments across the country have developed a variety of program models that have been successfully implemented. The PACE assessment is filed with the local municipality as a lien on the property.[28]

Our Team did not find any community solar projects that have used PACE loans for financing their project. PACE loan payments are linked to a building through a tax lien and paid off through a property's tax bill. For PACE loans to be viable for community solar projects, the solar asset needs to be onsite a building. Our Team's interview respondents (including contacts among non-utility program administrators, policy experts, and national laboratories) speculated that if it is possible to establish a permanent (or quasi-permanent) link between the solar asset and the building, community solar project developers could potentially use PACE financing. PACE implementation varies by state and local governments, and it is recommended that local jurisdictions explore the potential of expanding PACE financing frameworks so that this financing mechanism can be made available for community solar projects.

5.7 Impact of Location and Siting

This section summarizes findings from research question 2.5. It summarizes the importance of the location and siting of community solar projects.

The TRC Team's research indicates that the location of a community solar project has significant project impacts including project costs, grid benefits, grid impacts and overall value of the project to the utility and its customers. The costs and benefits of a community solar project vary by location and locational variation in the condition and capacity of the transmission and distribution (T&D) infrastructure. The solar asset might require the utility to make infrastructure investments when overloaded circuits need to be upgraded to accommodate the interconnection of a solar system. Although no industry consensus exists on the optimal location, siting and scale of a community solar project, the below discussion provides key considerations for project siting:

- *Price of Land:* The price of land is a significant driver of community solar and typically precludes location in urban and congested areas. For a typical 500 kW to 2,000 kW community solar project, approximately 3 to 12 contiguous acres are needed, depending upon solar equipment selections and designs (U.S. EPA, 2016). Public land (municipal, county, or state-owned) is typically cheaper than private land. Although rural areas have the least expensive land prices, these areas typically lack the customer electricity demand sufficient to support the construction of a community solar project. Further, some regions restrict the development of rural farmland for solar projects.
- *Local Requirements:* Local jurisdiction zoning, permitting and licensing requirements for community solar projects need to be considered. The quest for community solar cost-competitiveness has led to industry debate over the proper location for a community solar (CSVP & Navigant, 2016). Some states specify that community solar should be located on the distribution grid or meet "community scale" size restrictions. For example, Minnesota law limits community solar projects to one MW each, in maximum groupings of five co-located projects; and California's community solar law states that projects should be "in reasonable proximity to enrolled participants." These locational issues may impact a developer's ability to locate their project in cost-effective locations.
- *Interconnection Cost Uncertainty*: Developers are usually responsible for the costs of connecting their projects to the grid, including any study costs and upgrades needed to accommodate their projects. In

[28] http://pacenation.us/wp-content/uploads/2016/10/PACEBasics_2016_10_7.pdf

most cases, interconnection rules specify application fee amounts needed to cover processing and other administrative costs, and are typically scaled to project size, but the total cost to interconnect might be unknown for the project. The location of the project can considerably impact the interconnection costs of a community solar project impacting the cost of the program to customers. State regulators can improve cost certainty and predictability by requiring utilities to track and report the actual costs of system upgrades and assigning resource values for identified high-value locations. This was attempted in Minnesota' community solar gardens proceeding when the state's Public Utilities Commission ordered Xcel Energy to report all variances between its interconnection cost estimates and the actual costs in its regular community solar garden reports. For variations exceeding plus or minus 20 percent, the commission required Xcel to provide a detailed explanation for the variance.

The TRC Team's interview respondents across multiple stakeholder types described that developers bear the risk when an estimate of interconnection costs is not available, as is currently the case for the IOU community solar program in California. High interconnection costs result in higher costs to the customer. Respondents among regulators, policy experts, and national laboratory contacts also expressed the view that the locational benefits of solar should accrue to the customers; were this the case, prospective customers would not know the bill credit or advantage they would receive from community solar until the locational benefits are estimated. Respondents recommended that utilities identify interconnection costs and value of solar cost associated with different locations. Having interconnection information and hosting capacity maps or pre-screens developed by the utility can help developers weed out sites that are not viable. Providing interconnection and value information provides clear economic signals that ultimately reduce costs for the utility, the developer, and the asset customers. One policy expert noted a New York community solar program that provided interconnection information received "lots of bids," which the respondent credited, at least in part, to the information regarding possible interconnection costs.

- *Grid Impacts*: The location of community solar projects will need to be modeled and examined for their impacts on power flows and voltage implications on the grid. Whether a community solar project is located near the substation or close to the load, the net effect on the primary feeder is the same. The power that is injected by the project will displace power drawn from the substation transformer. However, at times when the generation exceeds the load, its location can cause voltage control problems if it is located far from the substation. Under those conditions, the power flow will reverse toward the substation, which can result in incorrect operation voltage regulators and capacitor banks.

  Even under conditions where the load equals or exceeds the power produced, an increase in reactive power demand can occur if the reactive power (VAR) produced by solar does not closely match the primary system power factor. Most utilities prefer that DER sources do not provide active voltage regulation, which would address this latter problem directly; however, it is usually possible during the modeling stage of interconnection design to select a fixed power factor set point for the DER that will avoid excessive reactive power flows toward the DER installation. Installing the DER close to the substation reduces or eliminates voltage regulation concerns and does not affect pole mounted regulators or capacitor banks on the feeder system. Modeling will have to determine that under all conditions of substation load the operation of the DER will not cause excessive operation of any substation installed voltage regulators or the load tap changer on substation transformers. In either of these scenarios, power provided from the DER will offset power consumption of the community load. The net kWh to and from the utility grid does not change. There is no more or less benefit to the community or to the utility in either case.

  The TRC Team's interview respondents among multiple stakeholder types expressed the view that although community solar can be developed to provide transmission and distribution (T&D) benefits, there is little agreement on estimated monetary benefits to the grid or even available methods to estimate such benefits. The interview respondents expressed the view that locational benefits are real and should be recognized in utility payments for the output of community solar assets. Respondents recognized that grid benefits are challenging to estimate, vary throughout the service territory, and change frequently due to changing energy usage patterns and changing infrastructure conditions. Potential locational benefits identified by our interview respondents include alleviation of distribution constraints and line losses, and improved frequency and voltage regulation.

5.8 Role of the Utility and Planners

This section summarizes findings from research questions 2.4 and 3.1. It provides an understanding of the critical role utilities and local planning authorities need to play in enabling the community solar market.

5.8.1 Utility Role

The TRC Team's research has identified that local utilities have a critical role to play in the development of the community solar market. Regardless of the ownership structure of the project, utility participation and cooperation are essential, as the project's output will be likely tied to the grid. Community solar offers utilities an opportunity to offer renewable energy choices to customers who are unable to access rooftop solar, and to retain customer loads that may be lost to rooftop solar providers. This model can provide utilities a viable mechanism to meet regulatory requirements for RPS and mitigate climate change, as well as test alternative rate structures and grid stabilization strategies.

The Community Solar Value Project strongly advocates for utility leadership in this market. Utilities can add value and potentially lower costs of community solar programs that are developed in-house or outsourced to third parties. Examples of utility-led community solar innovation include the following:

- *Project Siting:* Utilities can help in identifying appropriate project sites and reduce 5 to 7% of developer's costs that are associated with site selection (CSVP & Navigant, 2016). Utilities can leverage relationships with local governments and other utilities (e.g. water utilities) to obtain good project sites, identify strategic sites where adding solar could add grid benefits, and alert developers about solar sites that would pose issues and/or risk. The help of the utility in identification of project sites would also ease the permitting process for developers and provide them additional cost benefits. For example, Cook County, Chicago successfully conducted workshops with nonprofits and local governments through which it identified 700 potential project sites. U.S. DOE's Sunshot project then conducted technical assessments of the sites and reduced to contenders to 200 sites.
- The TRC Team's interview respondents among policy experts and national laboratory contacts voiced the opinion that the California IOUs are "well on their way" to understanding the T&D value of solar at locations throughout the state. A recent ruling in California to improve cost predictability is the development of unit cost guides which require the IOUs to publish annually updated guides to inform developers and customers with a list of standard prices for typical interconnection facilities and equipment. This information can help community solar project developers examine potential sites and the interconnection cost implications of locational issues. The Oregon PUC also has an open docket on the Resource Value of Solar (RVoS) which will require utilities to support the calculation of the location-specific value of solar.
- Many of the TRC Team's interview respondents of differing stakeholder types expressed the view that all stakeholders (regulators, utilities, developers, and customers) need to recognize that the resource value of potential sites cannot be known with precision. It is complex to calculate and it can change over time with changing infrastructure and market conditions. Respondents did not think that lack of certainty in

the estimated values is sufficient reason to force the risk onto developers or to deny customers payment commensurate with the value of the asset. In the words of one non-utility program administrator, "Small numbers count. A quarter-of-one cent, or even less, adds up to fill the gap between developers starting price and their bottom line best offer." Our Team's respondents also think that utilities should reduce developers' risks and optimize the costs and benefits of community solar by publicizing its resource value, a move that would benefit consumers. Respondents among multiple stakeholder types advocated that regulators and utilities should assign resource values great than zero for identified high-value locations and that these estimates should be used in planning. If adopted, the VOS approach has the potential of replacing NEM and VNEM rates in the future.

- *Customize Offerings to Meet Low to Moderate Income Market Needs:* Utility partnership with third-party developers and non-profits could help develop service offerings and participation models that focus on low- to moderate-income needs.
- *Incorporating Companion Measures:* Utility involvement can create an opportunity to test colocation of other technologies that boost the grid-integration value but do not necessarily provide immediate pay-off for developers. For example, Austin Energy provided a subsidy to locate a utility-side storage battery with its community solar project. Although the storage project runs separately and did not offer an immediate return on investment, the utility hopes to gain experience with storage and offered customers a chance to participate in its Integrated Distributed Energy Resources (iDER) strategy. Steele Waseca Electric Cooperative used water heaters as a currently economical storage companion measure for community solar.
- *Procurement Process as Market Enabler*: The utilities can structure the procurement process to enable economies of scale in this market. For example, utilities can deploy similar community-scale projects under one procurement and also provide price adjustment mechanisms for long-term projects. This approach could help developers plan effectively for adding capacity to projects built out over time and provide geographic diversity of projects compared to one large-scale project.

5.8.2 Planning Agencies

Local communities, planning agencies and building departments can create incentives by streamlining the approval process, reducing permitting costs, and increasing flexibility for developers. Some approaches for local planning agencies to enable the community solar market are provided below (APA, 2013):

- *Designating solar as a primary land use:* The scale of community solar projects compared to rooftop systems has more on land use and may give rise to public concern. Planning departments can promote and enable community solar projects by designating solar as a primary land use (See Section 5.4.2 for examples). Planning agencies can identify and allocate suitable locations for community solar projects and also establish development standards such as height limitations, lot sizes, stormwater management, setbacks from property lines or neighboring structures, and screening from adjacent public rights-of-way. This helps developers of community solar projects easily identify appropriate sites and develop their projects according to the established rules and regulations.
- *Provide assistance in community solar project development*: Planning departments can provide assistance in the development of community solar by providing assistance in the identification of potential sites, leasing or donating municipal sites, providing solar mapping tools, providing financial assistance, loans and other technical assistance to remove any potential barriers and challenges developers might face. Some examples include:

  - City of New Bedford, Massachusetts allowed ConEdison Solutions to install solar panels on multiple city-owned sites, including schools, municipal buildings, and brownfields, purchasing the power generated by these solar systems.
  - City of Richmond, California in collaboration with the National Renewable Energy Laboratory (NREL) developed a decision tree to help the city assess the potential for solar energy projects on all known brownfield sites. NREL and Environmental Protection Agency (EPA) subsequently created a general solar decision tree, available through EPA's Re-Powering America's Lands website[29] to help all communities and interested parties assess the solar redevelopment potential of any site.
- *Streamlining permitting processes:* Planning departments and local jurisdictions can streamline the development review process and incentivize community solar redevelopment by reducing development review or impact fees and local property taxes, providing expedited permitting and removing other barriers which can help reduce costs or make it easier for community-scale projects to obtain the needed permits for building such projects. Examples include:
  - San Jose, PA, Portland, OR, and Philadelphia, PA have developed streamlined solar permits that replace separate building and electrical permits. Both of these cities also provide guidance materials through department websites to help potential developers navigate the permitting
  - Other cities such as Tucson AZ, Surprise, AZ, Irvine, CA, have passed resolutions to temporally waive permitting fees for solar projects as a mechanism for successfully stimulating the market.
- *Support project operations*: Planning agencies and local jurisdictions can minimize operational barriers related to the interconnection process by developing standardized interconnection agreements and educating planning and building staff officials about local interconnection procedures. A couple examples of municipal utilities with standard agreements include the Sacramento Municipal Utility District in California, Colorado Springs Utilities in Colorado, and Fort Pierce Utilities Authority in Florida. Once systems are operational, municipal utilities can extend ongoing support to solar redevelopment projects by purchasing power and RECs from producers. States (and some municipal utilities) support the REC demand by adopting RPS.

5.9 Community Solar Opportunities and Barriers

The TRC Team's research identifies some key barriers and opportunities for community solar that need to be understood from the perspective of key stakeholders in the market, such as local governments, utilities, developers, and consumers. The project economics must be attractive for all relevant stakeholders. In states with low retail electricity rates and/or low compensation mechanisms, community solar projects are less attractive and will require subsidies or require consumers to pay a premium. Figure 14 summarizes key opportunities and barriers for the different community solar stakeholder groups, and they are described below.

[29] www.epa.gov/oswercpa

Stakeholder	Opportunity	Barriers
Local Govt.	o Positioned well to incentivize community solar	o Lack of master planning
Utility	o Mechanism to comply with regulatory mandates o Provide additional services to existing customers o Ability to retain customers otherwise lost to rooftop solar o Mechanism to test innovative renewable grid integration approaches	o Program management o Utility bill crediting o Program financing complications
Developers	o Significant market potential and growth opportunity o Expanded customer base o Community-scale potentially more financially viable than rooftop solar o Large market and demand can allow innovative financing and pricing models	o Need to be supported by enabling regulations o Program financing complications o Potential conflict between federal and state level tax requirements
Consumers	o Access to solar energy for all consumers o Can offer affordable pricing options than rooftop solutions	o Lack of knowledge and information

Figure 14: Summary of Stakeholder Opportunities and Barriers

- **Local Governments**: Government organizations are well positioned to recognize the market barriers facing community solar growth and have available tools that they can leverage for creating the needed support system and facilitate change.
  - *Opportunities*: Local governments can offer great opportunities for promoting the community solar market through supportive policies, regulations, incentives and other supporting services. For example, local governments can identify high potential and high-value solar sites, mandate flat-roof industrial and large commercial spaces (such as retail, grocery) to require solar, and offer financial incentives for projects. Local governments could also engage partners from the private sector to monetize benefits from parking structure solar canopies
  - *Barriers*: The main local government barrier to community solar is the lack of solar development consideration in master planning efforts. To encourage community solar, local governments should update their policies by passing new ordinances to encourage solar projects and streamline the permitting process. Recommended issues for clarification at the master planning stage include: identification of solar zones and issues of siting solar projects, solar mounting regulations for roof and ground mounted systems, solar access and solar easements provisions, permitting requirements, etc. One policy expert elaborated on the need for master planning and thought that

municipalities should require master planning, including plans for both site-based and community solar, and should seek the most cost-effective combination of site-based and community solar.

- **Utility**: In many states, the utility role in community solar is defined by legislation and regulatory policy and may be limited to grid interconnection issues or compensation mechanisms. The lesser regulated municipal or consumer-owned utilities might have more flexibility in participation in the community solar market.
  - *Opportunities*: As mentioned in this report, the community solar market offers a unique opportunity for utilities to offer their customers an additional way to participate in the solar market, retain customers that might be lost to the rooftop solar market and also test out new innovative mechanisms for pricing, new technologies (storage, demand response etc.), grid integration strategies, etc. Utilities are well positioned to expand their participation in the community solar market by leveraging information and knowledge about high potential strategic sites, easy access to customers, existing pricing mechanisms, financial stability and access to capital for investment and other infrastructure needed to support community solar projects.
  - *Barriers*: The biggest utility concerns with community solar is focused on administrative management, integration of the community solar program into the billing system and navigation of state and federal regulations such as tax incentives and securities law. Participation of utilities in partnership with third-party developers can help resolve administrative issues and provide the needed resources for program design, marketing and customer acquisition, and billing/IT. These partnerships can be particularly beneficial for smaller utilities, municipalities, and cooperatives that might be resource constrained and unable to spend the internal resources to enter the community solar market.
- **Developers**: The opening up and the growth of the community solar marketplace has created new opportunities for solar developers.
  - *Opportunities*: Developers are positioned well to see an enabling market environment for future projects across the country, and hope to see an expanded customer base under a shared solar regime. Community solar projects also help to reduce the upfront cost of solar power compared to individual ownership, due to the expanded scale of the project.
  - *Barriers*: Developers must provide the upfront capital and bear the risk of the initial investment. Developers are also burdened by cash flow challenges and the need to navigate and balance multiple revenue streams that may include a complicated array of options such as tax incentives, rebates, and bill credits etc. Developers also face the challenge to track and navigate a wide variety of rules and regulations across local jurisdictions. This creates additional administrative work and operational cost to develop projects in different locations. The legal complications of potential misalignment between federal renewable energy incentives paid through the tax code and the local non-taxable status of many renewable energy projects can cause challenges for developers who may need to forgo one of the two available incentive mechanisms. Reconciliation of these contradictions and a level playing field can help improve project economics and offset some of the legal, accounting and administrative costs for developers. Sometimes, developers can be constrained by DER limits and other generation and/or interconnection restraints put forth by utilities and the existing regulatory regime.
- **Consumers**: The end users will benefit the most with the continued growth of the community solar market with new ways of accessing clean energy and a more competitive solar market.

- *Opportunities*: One of the biggest challenges for potential consumers is the lack of knowledge and awareness about community solar programs. These programs are relatively new and are not well understood by the public, even in the 18 states plus Washington D.C. that have legislation enabling community solar.
- *Barriers*: Consumers are also looking for a program that offers a lower cost of electricity than the standard tariff or a tariff they may be able to receive by signing a power purchase agreement for rooftop solar. Customers are looking for a low up-front capital investment or ideally no startup costs and flexible contractual agreements. Although community solar is potentially well positioned to address these consumer needs, most existing programs have not matured enough to offer these desired terms and conditions — limiting consumer participation.

5.10 Community Solar Outlook

This section summarizes findings from research question 2.1. It provides an understanding of the future market potential of community solar in the U.S., and provides some examples of emerging models.

The community solar market has the potential to grow more than 50-fold from 2016 capacity to between 5,500 MW and 11,000 MW by 2020 (NREL, 2015). An important reason for this growth is the potential for community solar to bring new demand into the solar market and making it viable for small-scale solar customers (50 kW - 2,000 kW) to purchase shares of a solar installation rather than hosting the installation themselves. The EPA RE-Powering America's Land Initiative has identified 9,500 RE-Powering[30] sites, representing 8,800 – 15,200 MW of technical solar photovoltaic potential available for development in the 26 states that currently have community solar projects (U.S. EPA, 2016). Neighborhoods in close proximity to RE-Powering sites generally have a higher than average percentage of households with income below the poverty line, due to lower rental and ownership price points in those areas. Community solar can have a particularly positive impact in low- and moderate-income (LMI) areas by overcoming home ownership, financing, contract flexibility and project size issues that typically shut out LMI communities from solar access. Community-scale solar is also inclusive to renters, apartment dwellers, homeowners with no suitable roof, and LMI households. In states such as Colorado and New York, community solar laws include a carve-out or preference for LMI subscribers, and California's SB 43 also directs utilities to actively market the GTSR to low-income and minority communities and customers. Rural electric cooperatives are using community solar to serve LMI members (RMI, 2016).The following section provides some of the trends and the major changes expected in community solar market in the future.

- Community-scale projects are expected to grow with most programs and projects planning to construct additional community scale capacity in order to keep pace with growing demand (NREL, 2015).
- Utilities are introducing a new generation of community solar projects that go beyond bigger arrays and premium pricing. Although few utilities have implemented community solar projects with other companion measures (e.g. storage, demand response, energy efficiency), utility interest exists in developing solar with other measures to make the most use of community solar as a grid asset. For example, Steele Waseca Electric Cooperative (SWCE) community solar Sunna Project has a solar PV capacity of 102.5 kW and was designed, developed and owned by the utility. Subscribers can participate

[30] RE-Powering sites represent a large and varied collection of sites that include former Superfund sites, brownfields, landfills, and mine sites, as well as other formerly contaminated sites under various federal and state cleanup programs.

by paying an up-front fee of $1,225 for 20 years of output from a 410 W panel. The next-generation variation is that subscribers who opt to participate in SWCE's demand response program get a free, 16-hour storage water heater and a $1,055 discount from the upfront cost of the first solar panel. SWCE recoups these investments through additional electric sales from the water heating and the savings on wholesale power costs by shifting purchases dedicated to water heating to off-peak hours. As utilities begin to see in next-generation programs more flexibility and reliability for the grid and greater appeal to their customers, more projects are expected to be developed (Utility Drive, 2016).

One interview respondent discussed the efforts of the CSVP which focuses on strategic solar technologies, siting, design and also encourages utilities to integrate companion measures of demand response, energy storage, energy efficiency, and resiliency planning in a "solar plus" approach. These companion measures have the potential to mitigate the "duck curve," low load factor, and steep load increase created by solar resources. CSVP advocates a fleet approach, whereby the utility manages a portfolio of community solar projects that are developed over time. A fleet approach takes the long view. It offers fleet pricing, and as costs fall over time with technological innovations and resource optimization, all subscribers (both early and late) benefit equally in the lower prices. The respondent noted that over time the solar resource capacity may reach a maximum due to constraints of the project site, land available etc.; but the utility can continue to modify the companion measures to increase the value of the resource to utility and end use.

- The future of community solar is expected to introduce additional payment options for subscribers. Initial projects were built around an up-front payment model, but newer, larger programs are removing the need to make up-front payments. Leading independent third-party developer Clean Energy Collective (CEC)'s initial model in Colorado was an upfront payment; but have since launched SolarPerks in Massachusetts and other programs across the nation, which eliminates the upfront payment (Utility Drive, 2016).
- The market is expected to see new business models emerge, with the utilities expected to play a greater role and develop additional partnerships with third-party developers. In many cases utilities are interested in building and maintaining the array but willing to turn the handling of customer acquisition, customer-project interfacing, and billing and credit management over to third-parties.
- Next-generation projects are expected to continue responding to these growing consumer preferences such as providing low-cost options to access community solar projects; or the ability to track the output from their share of the project in real time through an app or a web-portal (Shelton Group & SEPA, 2016).

To summarize, the future outlook for community solar is expected to be more customer focused, and offer competition to the rooftop solar business model. The additional choices, and hopefully flexible participation choices will contribute to broaden the adoption of clean solar power by populations that are currently not being served by the rooftop market.

5.11 Community Solar Findings and Lessons Learned

The TRC Team analyzed the research findings from literature review, SME input, TAC input and the stakeholder interviews and summarized them into the following lessons learns regarding the community solar market.

- Community *solar market is growing but still in the nascent stage:* The community solar market nationally is well positioned for growth. However, California's market is nascent with limitations to near-term growth under the current GTSR program structure. Both components of the GTSR have certain challenges that need to be overcome:

- The Green Tariff needs to overcome the barrier to high price premiums as compared to alternative options, and in its current form it cannot compete with the currently lucrative NEM credit rate for rooftop solar.
- The ECR program is off to a slow start during the first round.[31] Challenges include: low and uncertain bill credit; developer demonstration of community interest requirements; securities opinion requirement; and other compliance obligation barriers.[32]

♦ *Evolving market*: The community solar market will continue to evolve in terms of ownership models, financing mechanisms, regulatory mechanisms and program offerings. New and innovative business models will need to be examined and evaluated and the lessons learned from this rapidly evolving market will continue to inform future market offerings.

♦ *Impacts on Grid Planning:* Tracking mechanisms and grid impacts require deeper quantitative examination than the qualitative assessment scope of this project.

♦ Role *of community solar in ZNE implementation:* The community solar market can support ZNE implementation in California, but more work is needed to align California's community solar program with the emerging ZNE regulatory model. The current community solar program structure was developed without taking into consideration the state's ZNE goals and the Title-24 ZNE requirements. The ZNE mandate in Title-24 could provide an additional market impetus for the growth of this market and represents an untapped value stream for community solar. New community solar program models should be explored to inform this policy direction. Exploration of new program models should carefully consider the following:

- Successful examples and best practices underway locally in California and across the country with focus on the credit value placed on community solar ($/kWh);
- Stakeholder roles in supporting each community solar business model;
- Whether community solar systems that sell RECs for RPS or otherwise retire those RECs qualify for meeting the ZNE goals;
- Currently envisioned ZNE regulatory framework for residential and commercial buildings through the California building standards;
- Ownership and financing models oriented to function within the envisioned ZNE regulatory framework;
- Quantitative examination of the energy tracking mechanisms and grid impact components of new program models;
- Tactical considerations including insurance payments, contract length, planning processes, and incentive mechanisms.

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[31] https://www.greentechmedia.com/articles/read/a-rough-start-possible-reforms-for-californias-community-solar-program

[32] http://www.lawofrenewableenergy.com/2017/03/articles/solar/results-from-californias-first-community-solar-rfo/

6. Synthesis of Findings: Community Biomass

This section summarizes findings from research questions 4.1 - 4.4 .1. It provides an understanding of California' community biomass market in the context of lessons learned from ten case studies.

6.1.1 Community Biomass Landscape in California

Bioenergy is a multi-faceted renewable energy source, and, unlike wind, solar, or hydropower, the fuel feedstock has a cost, or in some cases creates an additional revenue source, to the accepting bioenergy facility. Considerable work and investment must be made to ensure that there is an adequate, economic, and sustainable feedstock supply to a bioenergy facility for much, if not all, of the facility operating lifespan. Nearly all bioenergy feedstocks are waste products, which have the potential diverted to higher uses, such as electricity or alternative transportation fuels rather than being disposed of in landfills, or eliminated by open pile burning (in the case of woody biomass waste in agricultural and forested areas).

California's agricultural and forestry industries and its large population give the state a large and diverse biomass resource base. The biomass in California totals 78 million gross bone dry tons per year (BDT/yr.) from multiple resources. Roughly 45% of this resource (35 million BDT/yr)is considered to be technically available for electric energy conversion- representing 4,650 MWe and 35 TWh of electrical capacity- as shown below in Figure 15 (CA Biomass Collaborative, 2015).The remainder is either available in sensitive habitat areas, on steep slopes not suitable for harvesting, is needed to be preserved to maintain soil tilth and fertility, or unrecoverable by harvesting and recovery equipment. The full extent to which this resource can be managed for energy production remains speculative due to uncertainties regarding the gross magnitude of the resource, quantities that can be sustainably harvested, variable costs of producing, acquiring, and converting the large amounts of biomass and the large variation in conversion efficiencies of the technologies adopted.

CATEGORY	Gross Resource (Million BDt/Yr.)	Technical Resource (Million BDt/Yr.)	Gross Electrical Capacity (MWe)	Technical Electrical Capacity (MWe)	Gross Electrical Energy (TWh)	Technical Electrical Energy (TWh)
Agriculture	25	12	2360	990	15	7
Forestry	27	14	3580	1910	27	14
Municipal	26	9	3957	1750	29	13
Total	**78**	**35**	**9897**	**4650**	**71**	**35**

Figure 15: Biomass Resources and Electricity Generation Potential in California

Given the various legislative, regulatory, policy, and energy pricing initiatives in California (see Section 6.1.2), as well as increased grant funding opportunities from various California agencies (i.e., CEC, CalRecycle, and the California Department of Food and Agriculture (CDFA) over the last few years, scores of new (and renewed) community scale bioenergy projects are being proposed throughout California. The IOU's in California are also focusing on supporting bioenergy development in the state. For example, Southern California Gas Co. (SoCalGas) recently announced new initiatives that will make it easier for renewable gas production facilities to connect to the company's natural gas pipeline system[33]. These initiatives include the launch of a new renewable gas website which provides (i) general information on biogas derived renewable natural gas; (ii) provides a downloadable toolkit to assist biogas producers and developers; (iii) explains the monetary incentive program for utility interconnection projects. SoCalGas also reviewed and upgraded its processes smoothen the path to interconnection for renewable natural gas developers. The company will complete its first renewable natural gas interconnection project in Perris, California[34] in summer 2017.

The TRC Team's review of CEC Electricity Program, CalRecycle, and the Department of Food and Agriculture (Dairy Digester Research and Development Program) grant awards reveals that since 2015, at least 5 woody biomass to electricity projects, 8 anaerobic digestion (AD) to electricity projects, and 6 dairy digesters to electricity projects were awarded with over $70 million in grant funds. The competition for grant funds has been intense with numerous applications for each award solicitation. For example, the 2014-2015 CalRecycle Organics grant solicitation received 44 applications (for both AD and composting) requesting a total of $108 million, to which only 3 AD projects were awarded a total of $9 million. In 2017 the Department of Food and Agriculture has received 36 applications for dairy digesters with a total funding request of nearly $76 million.

However, there are issues that nonetheless have impeded community-scale bioenergy development. These include:

- Low prices for electricity
- Lack of adequate financial resources for project development and capital expenditures;
- Financial feasibility of project;
- Obtaining adequate feedstock for AD projects
- Procurement of economically priced feedstock in the case of woody biomass projects;
- Receipt of adequate tipping fees in the case of AD projects;
- Deciding which AD technology to employ;
- Utility interconnect process and costs;
- Land use and environmental impact issues;
- Disposition of byproduct and residuals from bioenergy conversion systems.

The bioenergy projects examined for this study (Section 6.1.4 and 12) have seen these challenges as well, and have addressed them in varying degrees where possible. These challenges can be seen also as lessons learned (Section 6.1.5), which may assist the many more bioenergy projects needed in the state to address state policies, legislation, and regulations (Section 6.1.2).

6.1.2 California Biomass Policy and Regulatory Mechanisms

California is a national leader in the production of biomass power. In 2016, 5,779 GWh electricity in homes and businesses was produced from biomass by using forestry, agricultural, and urban biomass, and by converting

[33] http://www.biomassmagazine.com/articles/14640/socalgas-streamlines-process-to-support-renewable-gas-projects

[34] https://sempra.mediaroom.com/index.php?s=19080&item=137275

methane-rich landfill gas to energy (LFGTE); and processing wastewater and dairy biogas into useful energy. Biomass power plants produced 3.14 percent of the total electricity in California[35]. Given below is a summary of supporting policy and regulatory mechanisms that have enabled a vibrant biomass market in the state.

- *Senate Bill (SB) 1383 Reduction of Short-lived Climate Pollutants[36]:* California's SB 1383 creates goals for short-lived climate pollutant reductions in various industry sectors, including reduction goals for black carbon, fluorinated gases, and methane. Organic materials comprise two-thirds of the waste stream. This bill aims for a 75% reduction in the level of statewide disposal of organic waste from 2014 levels by 2025. It has been suggested by several bioenergy experts, that meeting this goal of a 75% reduction in landfilling of organic wastes will require as many as 150 to 200 new or expanded AD and composting facilities in California.
- *Assembly Bill (AB) 1594 Elimination of ADC[37]*: AB 1594 eliminates the diversion credit for using organic material as landfill alternative daily cover (ADC). This diversion credit had incentivized the use of organics in the landfill. The removal of this diversion credit does not prohibit the use of organics as ADC; however, without the diversion credit, landfill operators are incentivized to find alternative uses for organic materials to achieve diversion requirements.
- *Assembly Bill (AB) 1826 Commercial Organics Recycling*[38]: AB 1826 requires commercial generators to subscribe to composting or anaerobic digestion service for their organic waste. AB 1826 presents a phased approach to mandating large organic waste generators to begin source-separated diversion. This practice reduces the cost of organics collection and processing for value-added utilization. The timeline prescribed by AB 1826 is:
  - January 1, 2016: Local jurisdictions shall have an organic waste-recycling program in place. Jurisdictions shall conduct outreach and education to inform businesses how to recycle organic waste in the jurisdiction, as well as monitoring to identify those not recycling and to notify them of the law and how to comply.
  - April 1, 2016: Businesses that generate 8 cubic yards of organic waste per week shall arrange for organic waste recycling services.
  - January 1, 2017: Businesses that generate 4 cubic yards of organic waste per week shall arrange for organic waste recycling services.
  - August 1, 2017: and Ongoing: Jurisdictions shall provide information about their organic waste recycling program implementation in the annual report submitted to CalRecycle. (See above for a description of information to be provided.)
  - Fall 2018: After receipt of the 2016 annual reports submitted on August 1, 2017, CalRecycle shall conduct its formal review of those jurisdictions that are on a two-year review cycle.
  - January 1, 2019: Businesses that generate 4 cubic yards or more of commercial solid waste per week shall arrange for organic waste recycling services.

[35] http://www.energy.ca.gov/biomass/

[36] https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB1383

[37] https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201320140AB1594

[38] http://www.calrecycle.ca.gov/recycle/commercial/organics/

- Fall 2020: After receipt of the 2019 annual reports submitted on August 1, 2020, CalRecycle shall conduct its formal review of all jurisdictions.
- Summer/Fall 2021: If CalRecycle determines that the statewide disposal of organic waste in 2020 has not been reduced by 50 percent of the level of disposal during 2014, the organic recycling requirements on businesses will expand to cover businesses that generate 2 cubic yards or more of commercial solid waste per week. Additionally, certain exemptions may no longer be available if this target is not met.

- *Senate Bill (SB) 350 RPS Increase*[39]: SB 350 requires the following: 1) the amount of electricity generated and sold to retail customers per year from eligible renewable energy resources be increased to 50 percent by December 31, 2030; 2) the California Energy Commission to establish annual targets for statewide energy efficiency savings in electricity and natural gas final end uses of retail customers by January 1, 2030; and 3) provide for transformation of the Independent System Operator into a regional organization. SB 350 provides a stable market for renewable energy production.
- *Senate Bill (SB) 840 Public Resources: Energy*[40]: In January 2016, SB 840 was introduced to amend numerous parts of the Public Utilities Code, two of which are applicable to bioenergy. Section nine of the bill alleviates deposits required for forest BioMAT projects associated with utility interconnection, whereas Section 11 requires CPUC to hire the California Council on Science and Technology to review and make recommendations to revise pipeline biogas standards with respect to energy content and siloxane content. The bill was passed in August 2016 and signed by the Governor into law. Depending on the findings of the California Council on Science and Technology, some of the technical barriers for the injection of biomethane into the natural gas pipeline system will be reduced.
- *Senate Bill (SB) 859 Greenhouse Gas Emissions and Biomass*[41]: In January 2016, SB 859 was introduced to require the purchase of 125 MW of power by state IOUs, and publicly owned electric utilities serving more than 100,000 customers, from biomass facilities that generate electricity from sustainable forestry materials (80 percent) of which 60 percent shall be from biomass removed from high hazard zones as a means of forest fire mitigation. Biomass power facilities must have been operational by 2013 and contracts are to last five years. The bill was passed in September 2016 and signed by the Governor.
- *Assembly Bill (AB) 2313 Renewable Natural Gas Pipeline Infrastructure Incentive*[42]: In February 2016, AB 2313 was introduced and required the California Air Resources Board (CARB) to study and evaluate a strategy to increase the in-state production of renewable natural gas. The bill was later amended to increase the incentive for pipeline biogas interconnection from $1.5 to $3 million per project, and up to $5 million for a dairy digester cluster project. The bill also requires the CPUC to consider rate-basing and other options to promote pipeline biogas once the current incentive program expires. It was passed in September 2016 and signed by the Governor and is codified in the CA Public Utilities Code Section 399.19.

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[39] http://www.energy.ca.gov/sb350/

[40] https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201520160SB840

[41] https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB859

[42] https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160AB2313

- *Governor's Emergency Proclamation on Tree Mortality*[43]: In recent years (before the 2016-17 rainy season) California had experienced severe drought conditions, which has led to an epidemic bark beetle infestation causing the death of more than 100 million California trees to date. In October of 2015, when more than 30 million trees had died, Governor Brown issued an emergency proclamation. This proclamation ordered numerous ways that agencies in California that would enhance the use of forest-sourced woody biomass in bioenergy projects. These included:
  - The CPUC to use its authority to extend contracts for existing bioenergy facilities receiving feedstock from high hazard zones (zones where extensive tree die-off has occurred, and/or continues to occur).
  - The CPUC to take action to ensure new forest bioenergy facilities that receive feedstock from high hazard zones get their power purchase contracts are expedited.
  - The CPUC to prioritize facilitation of interconnect agreements for forest bioenergy facilities in high hazard zones.
  - The CEC to prioritize EPIC grant funding for woody biomass-to-energy technology and development.
  - CalFire, CEC, and other appropriate agencies working with various public and private land managers, estimate biomass feedstock availability, storage locations, and volumes that may be available for use as bioenergy feedstock at existing and new facilities.
  - CalFire and CEC working together with bioenergy facilities using high hazard zone biomass to identify potential funds to help offset higher feedstock costs.

6.1.3 Enabling Financial Frameworks for Biomass in California

In addition to the above-mentioned legislative tools, California has numerous financial frameworks available which have also contributed towards supporting the biomass market. These include the following:

- *Electric Program Investment Charge (EPIC)*[44]: The Electric Program Investment Charge (EPIC) was created in December 2011 by the California Public Utilities Commission (CPUC) in cooperation with the California Energy Commission (CEC) to make clean energy investments (formerly the Public Interest Energy Research, or PIER, research and development program) to provide benefits to the electricity ratepayers of PG&E, SCE, and San Diego Gas and Electric. The primary focus of EPIC is on pre-commercial technologies, applied research, demonstration, and deployment projects. The EPIC website states that it will invest $162M annually from 2012-2020 primarily to address policy and funding gaps related to the aforementioned technologies. Although a 20 percent set-aside for demonstration and deployment bioenergy projects (equating to $100,000 to $5M per award) was instituted during the 2012-2014 funding period, the 2015-2017 EPIC Triennial Investment Plan did not specifically identify a funding profile for bioenergy projects to include biogas / biomethane endeavors.
- Numerous bioenergy projects, using woody biomass, food, and organic wastes have been awarded EPIC grants in the 2015-2017 cycle. Recently (April 2017) the CEC adopted the 2018 to 2020 EPIC Triennial Investment Plan, which again does not have a specific set-aside for bioenergy projects. It does discuss current key technical and market challenges to be addressed by EPIC funding such as gasification syngas

[43] https://www.gov.ca.gov/news.php?id=19180

[44] http://www.energy.ca.gov/research/epic/

cleanup, modular bioenergy systems for forest biomass resources, reducing air pollution emissions from biogas to electricity systems. The 2018-2020 plan is not proposing any new dairy digester research initiatives, as the California Department of Food and Agriculture (CDFA) is providing significant grant funds through its Dairy Digester Research and Development Program (DDRDP).

- EPIC funds are made available to all public and private entities and individuals with the exception of publicly owned utilities. In accordance with CPUC Decision 12-05-037, funds administered by the CEC may not be used for any purposes associated with publicly owned utility activities.
- *CalRecycle Organics Grant Program*[45]: CalRecycle offers a competitive grant program, which looks to lower overall greenhouse gas emissions by expanding existing capacity, or establishing new facilities in California to reduce the amount of California-generated green materials, food materials, or alternative daily cover (ADC) being sent to landfills. Eligible facility projects include Construction, renovation or expansion of facilities in California that compost, anaerobically digest, or use other related digestion or fermentation processes to convert organic or food waste materials into value-added products such as electricity. Grant funding includes the purchase of equipment, machinery and real estate improvements associated with the installation of such systems.
- *CDFA Dairy Digester Research and Development Program (DDRDP)*[46]: The CDFA provides financial assistance for the installation of dairy digesters in California to reduce greenhouse gas emissions. CDFA received $50 million from the Greenhouse Gas Reduction Fund in 2016 for methane emissions reductions from dairy farm and livestock operations. Of this amount, the DDRDP is allocating $29-36 million as financial assistance to support digester projects on California dairy operations.
- *CA Alternative Energy and Advanced Transportation Financing Authority (CAEATFA) Sales and Use Tax Exclusion (STE) Program*[47]*:* The STE offers a sales and use tax exclusion to manufacturers that promote alternative energy and advanced transportation. This can result in a small, but not insignificant, capital cost savings to bioenergy projects, as sales tax purchased equipment is generally 7.5% or higher. The STE program is currently authorized through 2020.
- *Self-Generation Incentive Program*[48]: The CPUC's SGIP has provided, and continues to provide, significant financial incentives to support existing, new, and emerging distributed energy resources. SGIP provides rebates for qualifying distributed energy systems installed on the customer's side of the utility meter. Bioenergy-related qualifying technologies include waste heat to power technologies, pressure reduction turbines, internal combustion engines, microturbines, gas turbines, and fuel cells. Applying for SGIP incentives is conducted through the four principal CA IOUs (PG&E, SoCal Edison, SDGE, and the SoCal Gas Co).
- *Senate Bill 1122 Bioenergy Feed-In Tariff (BioMAT)*[49] : BioMAT is a very significant tariff incentive program for community-scale bioenergy projects. It supplies premium electricity price payment to qualifying bioenergy facilities. In September 2012, SB 1122 was signed into law, requiring an incremental

[45] http://www.calrecycle.ca.gov/Climate/GrantsLoans/Organics/

[46] https://www.cdfa.ca.gov/oefi/ddrdp/docs/2017DDRDP_RequestforGrantApplications.pdf

[47] http://www.treasurer.ca.gov/caeatfa/ste/index.asp

[4848] http://www.cpuc.ca.gov/sgip/

[49] http://cpuc.ca.gov/SB_1122/

250 MW of renewable feed-in tariff (FIT) procurements from community-scale bioenergy projects (three MW or smaller) that commence operation on or after June 1, 2013. The statute required that each of California's three large investor owned utilities (IOUs – Pacific Gas & Electric, Southern California Edison, and San Diego Gas and Electric) must procure a share based on the ratio of their peak demand to statewide peak demand. Additionally, the statute specified that the CPUC should allocate the 250 MW in the following manner.

- 110 MW for biogas from wastewater treatment, municipal organic waste diversion, food processing, and co-digestion.
- 90 MW for dairy and other agricultural bioenergy.
- 50 MW for bioenergy using byproducts of sustainable forest management.

The pricing for the FIT was originally to be set by the Renewable Market Adjusting Tariff (ReMAT)[50], starting at $124.66 per megawatt-hour (MWh). However, in September 2015 the CPUC approved (with modifications) a more tailored Bioenergy Market Adjusting Tariff (BioMAT) at the request of the participating IOUs and the recommendation of an October 2013 consultant report prepared for the CPUC. The BioMAT program began offering PPAs on February 1, 2016, at $127.72/MWh, and in accordance with the program protocol prices have escalated (except for the urban category). As of August 1, 2017, pricing under this tariff model was set at $175.72/MWh for urban feedstocks, $187.72/MWh for agricultural feedstocks with $163.72/MWh for dairy digesters, and $187.72/MWh for forestry feedstocks .

AB 1923[51] was introduced in February 2016 and passed in September 2016 and amends the Bioenergy FIT to allow BioMAT projects to have a nameplate generation capacity of five MW if only three MW are exported to the grid, where the additional two MW are used on-site. Bioenergy projects not located within the service territory boundaries of PG&E, SCE, and SDG&E are not eligible to participate in the BioMAT program. Nor is wheeling of BioMAT bioenergy from the three IOU service territories to other electric utility territories allowed under the program. It should also be noted that the passage of SB 1122[52] also precipitated the establishment of the Bioenergy Association of California (BAC)[53]. The mission of the BAC is to promote sustainable bioenergy development and associated activities in California. The BAC has been heavily involved in the development of the BioMAT program.

6.1.4 Summary of Biomass Case Studies

One of the objectives of this study project was the examination of 10 California bioenergy projects in a case study review format, i.e. literature/internet reviews, interviews, and knowledge of the Biomass SMEs.

The TRC Team used the following criteria for the selection of biomass case studies:

- Case studies should represent a wide variety of available technology solutions for converting waste biomass to energy
- Case study projects should be representative of all major IOU territories

[50] http://cpuc.ca.gov/RPS_Feed-In_Tariff/

[51] https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201520160AB1923&search_keywords=energy

[52] https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201120120SB1122

[53] http://www.bioenergyca.org/

- Case study projects should be operating, under construction, or at least far enough along in the development stages to warrant possible examination

The TRC Team identified over 20 community biomass projects in California, and the list was then pared down to 10 projects after discussions with TRC SMEs, IOU's, TAC and industry stakeholders. The TRC Team also included projects selling power to projects not within the three major CA IOUs. The 10 selected projects represent the following three categories for electricity generation from biomass projects:

- *Anaerobic Digestion of Food and Organic Wastes*: Anaerobic digestion (AD) of food and organic wastes to produce electricity comes in many forms. It can be in-vessel anaerobic digestion of food waste, which has been source-separated at the point of generation; food/organic waste separated from municipal solid waste (MSW) after collection from the generators; fats, oils, and greases (FOG) collected from facilities and transported to AD and wastewater treatment facilities; dairy digesters which convert cow manure waste to electricity with possible future co-digestion of other organic wastes; landfill gas collection for pipeline injection or combustion in an internal combustion engine generator set; and potential direct conversion of woody biomass into bio-methane for use in electricity generation and transportation fuels.

- *Dairy Digesters*: The development of electrical power or transportation fuels from dairy farms in California is very important. California has been the nation's leading dairy state since 1993, when it surpassed Wisconsin in milk production. California is ranked first in the U.S. in the production of total milk, butter, ice cream, nonfat dry milk, and whey protein concentrate. Currently, there are more than 1,500 California dairy families, whose farms house 1.77 million milk cows. Approximately one out of every five dairy cows in the U.S. lives in California. These farms are primarily concentrated in the San Joaquin Valley. The economics of dairy manure anaerobic digestion dictate that it must be conducted at the site of generation as transportation costs per energy unit are very high due to high moisture content (which adds substantial weight) and the low energy yield of the manure feedstock (manure can be up to 10 times less energy dense than food waste – which is already about 4 to 6 times less energy dense than woody biomass).

- Small-*scale Woody Biomass Power*: Over the past few years, there has been considerable planning in California regarding the installation and operation of small-scale (also referred to as community-scale) woody biomass to electricity (and waste heat in some cases) systems in the 3 MW or less size range. This was originally driven by forest-based communities seeking solutions for reducing catastrophic wildfire. It has been determined that the thinning and removal of hazardous forest land fuels, which have built up over the last century of fire-suppression activities in California, is the best way to reduce wildfire occurrence and/or severity. However, there are challenges here as well, as the thinned materials must be removed or otherwise disposed of. Much of this disposal is via open pile burning. Such uncontrolled combustion is also undesired and thus control of these emissions is warranted. Strategic placement of community-scale biomass plants in the forest is being planned. The Watershed Training and Research Center via its role on the California Statewide Wood Assessment Team has indicated that over ten forest-sourced woody biomass plants in various stages of pre-development and development. However, there are currently no operating community-scale woody biomass facilities in California forests and only a few operating small biomass electricity facilities outside of the forest (currently less than one MW in scattered agricultural areas of Northern California.

Figure 16 below provides a summary of the 10 California bioenergy projects, which were further examined for this study.

	PROJECT TYPE	PROJECT NAME	UTILITY	ELECTRICITY GENERATION
1	Anaerobic digestion	UC Davis READ Biodigester	University of California, Davis (UCD)	<1 MW using Micro turbines and Organic Rankine Cycle
2		Kompogas San Luis Obispo	Pacific, Gas and Electric (PG&E)	< 1 MW using Internal Combustion Engine
3		Joint Water Pollution Control Plant (JWPCP)	Southern California Edison (SCE)	20 MW Gas and steam cycle turbines
4		East Bay Municipal Utility District (EBMUD) Main Wastewater Treatment Plant	Pacific, Gas and Electric (PG&E)	10.5 MW using Internal Combustion Engine and gas turbine
5		Zero Waste Anaerobic Facility	Pacific, Gas and Electric (PG&E)	1.6 kW using Internal Combustion Engine
6		Point Loma Wastewater Treatment	San Diego Gas & Electric (SDG&E)	4.2 MW using fuel cells
7	Dairy	Old River Road Dairy	Pacific, Gas and Electric (PG&E)	2 MW using Internal Combustion Engine
8		Van Warmerdam Dairy	Sacramento Municipal Utility District (SMUD)	600 KW using Internal Combustion Engine
9	Woody Biomas	Cabin Creek Biomass Facility	Liberty Energy	2MW using Internal Combustion Engine
10		North Fork Community Power	Pacific, Gas and Electric (PG&E)	2MW using Internal Combustion Engine

Figure 16: Biomass Case Studies Summary Table

Case Study 1: University of California Davis (UCD) Renewable Energy Anaerobic Digester (READ) Biodigester, Davis, CA.

The UCD READ Biodigester is located at the now-closed campus landfill, which is located west of the main campus complex in Davis, CA (See Figure 17). This case study was chosen to showcase the unique AD technology which was developed by UCD researchers.

Figure 17: UCD READ Biodigester (Courtesy TSS Consultants)

Operations commenced in December 2013, as one of the first food/organic waste standalone AD systems in California. It can generate up to 920 kilowatts of electric via microturbines (800 kW) using a combination of AD biogas and landfill gas, and an Organic Rankine Cycle genset (120 kW) using waste heat from the microturbines. The conversion technology is a high solids, wet fermentation anaerobic digestion system with a maximum annual capacity of 20,000 tons of organic and food waste feedstock. It is also unique in that the biogas production is further supplemented by landfill gas for the closed landfill. UCD owns and operates its own electrical substation and currently contracts with the Western Area Power Administration (WAPA) for electricity and pays PG&E a wheeling fee for the use of their transmission lines.

Originally built, operated, and owned by CleanWorld, an AD technology developer, it was recently purchased by the University. When CleanWorld owned the facility, UCD paid them $0.08 per kilowatt-hour. The technology and location were chosen as the CleanWorld AD technology, and the technology was originally developed by researchers at UCD (Dr. Ruihong Zhang, Department of Biological and Agricultural Engineering). UCD management wanted to showcase this new and innovative AD technology.

Initial project cost was $8.6 MM and was funded in part by a U.S. DOE grant, loan from CalRecycle, commercial loan from First Northern Bank, and some private equity. CleanWorld also received funds from the PG&E SGIP program. Electricity produced is fed to the UCD electric grid.

Successes and Challenges – The UCD Biodigester facility manager thinks that although there have been operational issues, the facility is a success because it showcases a UCD developed AD technology and the facility, being one of the first of its kind, is on a learning curve and will only improve.

The challenges, of course, have the operational issues, which have caused shutdowns and needed repairs to the system. It was originally envisioned that animal manure and bedding from the various animal healthcare facilities on the UCD campus would be a continuing feedstock for the AD facility. However, it has been determined that the higher cellulosic nature of the feedstock are not appropriate for the UCD AD technology.

Case Study 2: Kompogas San Luis Obispo, CA.

The Kompogas San Luis Obispo AD facility is currently under construction and is collocated with the Waste Connections solid waste transfer/processing facility at 4388 Old Santa Fe Road in San Luis Obispo, CA.

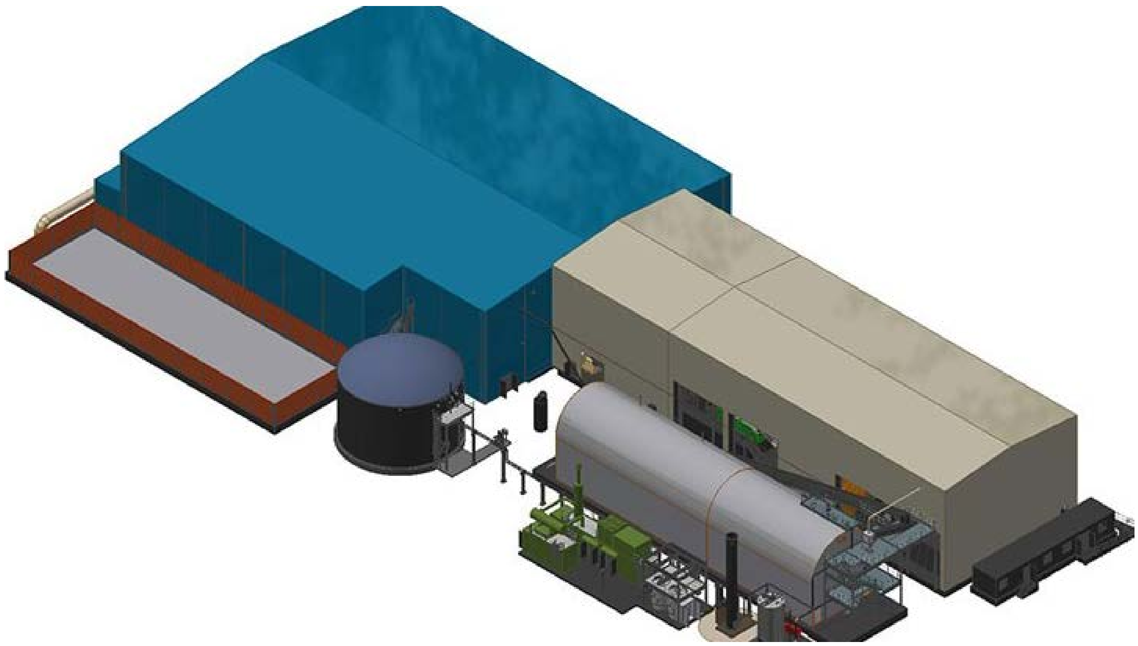

Figure 18: Schematic Drawing of Kompogas San Luis Obispo (Courtesy Hitachi Zosen Inova)

It is designed to generate 800 KW of electric via an internal combustion engine genset. The AD system itself is of the plug flow dry variety, which can process both green waste and food waste, with an annual capacity of 36,500 tons (100 tons per day). It has a significant tipping fee (not disclosed at this time) and a PPA under the PG&E BioMAT program with the electricity to be purchased at $0.1272 per kilowatt-hour. The facility also reports it has offtake contracts for both the liquid and solid digestate for use by local agricultural enterprises. Operations are expected to begin in late 2018.

The AD technology is originally of German design and is being built, and will be owned and operated, by Hitachi Zosen INOVA. Waste Connections issued a Request for Proposals looking for a solution to recycle green waste and food waste. Two responses were received, one for composting and one for AD. Given that the cost was similar for each, Waste Connections chose HZI given the advantages in GHG reduction, power to the local community, and compost for local agriculture.

Project costs are reported to be in the $18 to $20 MM ranges. Project financing is principally internal financing from Hitachi Zosen, plus $4MM from the California Energy Commission Electric Program Investment Charge grant program (officially awarded 8/10/17) and another $4MM awarded by the CalRecycle Organics Grant Program and announced on 8/15/17. Owner will also receive the 30% Federal Investment Tax Credit as construction on the facility began before the sunset of that program at the end of 2016.

Successes and Challenges – Although the facility is still under construction, it has all the features of a successful project to be. It is using a commercially-proven German technology which has been used at over 200 sites; a PPA with premium electricity prices is in place (a BioMAT PPA with PG&E); project is sited at a regional solid waste transfer and processing facility operated by a large waste collection company (Waste Connections, which services 6 million customers in the U.S. and Canada); a reported significant tipping fee; and offtake contracts for the liquid and solid digestate. The digester facility AD process can utilize both green waste and food waste, which is necessary for the region.

The principal challenge to this project was securing the appropriate tipping fee. The feedstock supplier (Waste Connections) had to get the 9 jurisdictions (cities and county) to approve higher solid waste rates to ensure a financially viable tipping fee to the AD facility.

Case Study 3: Joint Water Pollution Control Plant (JWPCP), Carson, CA.

The Los Angeles County Sanitation District (LACSD) is using wastewater digesters at its Joint Water Pollution Control Plant (JWPCP)[54] in Carson, CA to codigest processed food and organic waste into biogas, using this biogas to produce electricity. This case study was chosen as this wastewater treatment is one of the largest in the world, consists of numerous large wastewater digesters, and allows for co-digestion with food waste and not adversely affect wastewater treatment operations. This facility serves 3.5 million people in the Los Angeles Region.

Figure 19: Los Angeles County Sanitation District (Courtsey LACSD)

The large size of this facility allows it to generate up to 20 MW of electricity from the wastewater digestion process alone (via gas turbine and steam cycle gensets), which is nearly all used to power the treatment plant.

[54] http://www.lacsd.org/wastewater/wwfacilities/jwpcp/

As the JWPCP is very large with numerous wastewater digesters, the LACSD engineers believed that co-digestion with food waste would not adversely affect wastewater treatment operations. In 2012, LACSD began bench-scale tests with slurried food waste. In February 2014 LACSD commenced a multi-year demonstration program, using slurried food waste obtained in agreement with Waste Management (WM). Currently, the demonstration program uses 62 wet tons per day in one of the facility's digester, producing approximately 700 KW, exported to the grid via a SoCal Edison interconnection to the CalISO system at real-time prices. As the demonstration program appears successful, the food co-digestion will be ramped up to 335 wet tons per day. However, much of this additional biogas production will be diverted to the facility's Compressed Natural Gas fueling station for use as transportation fuel. Even further expansion is expected and might include pipeline injection of biogas, and possible export of electricity

For the demonstration program, no costs were given, but for expansions and upgrades:

- Expand system to process food (off-site at the Puente Hills Materials Recovery Facility), $1.8 MM.
- Upgrade systems at the JWPCP for the next phase (up to 335 TPD of food waste), $5MM.
- Construct new on-site food waste receiving system for the additional digesters needed for expansion, $7MM.
- Primarily financed out of LACSD solid waste management revenues.
- Recently received $2MM grant from CEC for food waste processing system.

Successes and Challenges – The project is considered a success so far. The initial demonstration phase showed that the introduction of food waste into the wastewater digesters did not create any problems, nor did it impact the treatment plant's number one goal – reliability of the treatment plant to conduct its main mission of wastewater treatment. When the co-digestion of food waste was proposed, the treatment plant operators expressed reservations, so the demonstration phase was initiated and later deemed successful with minimal impact of the wastewater treatment process.

Case Study 4: EBMUD Main Wastewater Treatment Plant, Oakland, CA.

The East Bay Municipal Utility District (EBMUD) is using wastewater digesters at its Main Wastewater Treatment Plant[55] in Oakland, CA to codigest high strength food and organic waste into biogas, using this biogas to produce electricity. As pioneers in food and organic waste codigestion in California, receipt of liquid organic wastes by truck (primarily septage and FOG – fats, oils, and greases) began in 2002.

[55] http://www.ebmud.com/wastewater/collection-treatment/wastewater-treatment/

Figure 20: East Bay Mud Liquid Organic Waste Trucks (Courtesy EBMUD)

The system was upgraded in 2004 to accept slurried food and organic waste with paddle finisher installed to remove contamination. In 2014 additional upgrades installed, such as blend tank receiving system.

Similar to the LACSD facility in Carson, CA, the Oakland EBMUD wastewater treatment facility consists of numerous large wastewater digesters, which would allow for co-digestion with food waste and not adversely affect wastewater treatment operations. It was originally developed at the current site due to a number of food processing facilities in the region (which are now gone). The EBMUD facility receives an average of 200,000 gallons of high strength organic and food waste per day. This results in approximately 3.5 MW attributable to organic/food waste. Another 2.5 MW comes from biogas generated from regular wastewater treatment. The facility produces approximately 130% of its internal electricity needs, with the surplus power is sold to the neighboring Port of Oakland by wheeling through PG&E.

Since 2002, approximately $21 MM has been spent for the organic waste collection, processing, and storage components of the facility. EBMUD depends on internal financing for construction of the system. Income from waste hauled to the plant's digesters is about $8 million per year. Tipping fees range from 3 to 11 cents per gallon for liquids; food wastes, which require much more handling, have tipping fees from $30 to $65 per ton. EBMUD is following the need for potential expansion based on additional food/organic waste landfill diversion needs per AB 1826 (mandated commercial organic waste recycling) and SB 1383 (reduction of short-lived climate pollutants).

Successes and Challenges – EBMUD considers the organic/food waste resource recovery system at EBMUD Oakland facility to be very successful and financially rewarding. The codigestion of the organics and food waste in EBMUD wastewater digesters does not significantly impact the wastewater treatment operations and allows the entire plant to be electricity self-sufficient. Additionally, expansion over the years and growth in the amount of organics and food waste being converted to electricity, allow EBMUD to export electricity to the nearby Port of Oakland and adding to its revenues.

Like the LACSD, the original challenge was to determine if there were any adverse effects of codigestion of organic/food waste with the primary mission of municipal wastewater treatment.

Case Study 5: Zero Waste Anaerobic Facility, San Jose, CA.

The Zero Waste AD facility in San Jose is located at 685 Los Esteros Road. It is a dry fermentation AD system capable of converting both green waste and food waste to biogas. Although it is currently processing 65,000 ton per year (178 tons per day), it has the capacity to process 90,000 ton per year (246 tons per day). Organic and food waste feedstock is received from the nearby Newby Island Resource Recovery Park (operated by Republic Services), with green waste received from the City of Palo Alto. Feedstock conversion mix is approximately 15 to 20% green waste to 80 to 85% organic waste. The facility generates 1.6 KW of electricity exported to the PG&E grid, using two 800 KW Catepillar brand internal combustion engine genset.

Zero Waste originally evaluated numerous AD technologies from Germany, and the selected technology was the most tolerant and flexible for the conversion of both organic/food waste and green waste in the same system. The site was primarily selected due to industrial zoning and related solid waste processing facilities adjacent and nearby. But, liquid digestate could also be discharged (and is currently discharged) to the City of San Jose sewer system (10,000 to 15,000 gallons per day) and solid digestate is trucked to a composting facility in Gilroy. Commercial operations of the Zero Waste facility began in November 2013

Figure 21: Zero Waste Site (Left) and Dry Fermentation Cells (Right) (Courtesy Zero Waste)

Project capital costs were $55MM, and the funding sources were $39 MM in bonds from the California Pollution Control Financing Authority, $12 MM in cash from the development company, and $4 MM from member companies. Revenues will come from electricity sales to PG&E under their BioMAT program, with sale at $0.1272 per kilowatt-hour. It is only one of two facilities in the state that currently have a PPA through the BioMAT program. Additional revenue will be realized from a tipping fee that averages $105 per ton of organic feedstock.

Successes and Challenges – Technically the AD project is a success because it demonstrates a new technology that converts both low moisture green waste and high moisture organic/food wastes, which assists the City of San Jose in meeting its goal of increasing landfill diversion (Goal #5 of the San Jose Green Vision Plan). It allows San Jose and other communities to address the requirements of AB 1826 by recycling commercial generated organic and food wastes. However, the facility is not meeting its financial goals. As the first of its kind dry AD system, and imported from Germany, there were significant cost overruns. Additionally, the organic and food waste delivered by Republic Services is generally contaminated and requires additional handling (which drives up costs to Zero Waste). Zero Waste continues to have difficulties receiving clean feedstock from Republic.

Case Study 6: Point Loma Wastewater Treatment Plant

The Point Loma wastewater treatment plant biogas production facility is located at 1902 Gatchell Road in San Diego, CA. And, the adjunct end-users of the pipeline-injected gas (fuel cells producing electricity) are located at the University of California, San Diego, and the City of San Diego South Bay Water Reclamation Plant. The only feedstock used for the AD-produced biogas is the municipal wastewater treated at the Point Loma facility. There is no organic/food waste feedstock codigested to create the biogas. The biogas produced and injected into San Diego Gas and Electric natural gas pipeline system is utilized by two fuel cells, 2.8 MW at UCSD, and 1.4 MW at City of San Diego South Bay Water Reclamation Plant. Currently, it is the largest fuel cell project in U.S.

Figure 22: Point Loma Biogas Facility (Courtesy Biofuels Energy, LLC)

The location of project was essentially chosen by the City of San Diego, who issued a Request for Qualifications to use the Point Loma Wastewater Treatment Plant digester gas for beneficial use (as opposed to being flared). The City of San Diego issued a RFQ in January 2007, with biogas agreements and project financing conducted from 2007 to 2010. Construction began in December 2010 with the biogas collection, cleanup, and pipeline injection construction, along with the installation of fuel cells at University of California, San Diego, and City of San Diego South Bay Water Reclamation Plant completed late 2011. Commercial operation began in January 2012.

The project cost was $45MM including fuel cells installation. Project financing was with New Energy Capital providing equity capital along with the New Market Tax Credits and Self-Generation Incentive Programs ($14MM). Grants, credits, and incentives totaled $33MM.

There is a potential that the facility will move from supplying biogas for electricity to supplying biogas to transportation fuels. The facility is currently receiving about $12 MMBTU for fuel cell conversion to electricity. The market for transportation fuels is currently in high $20’s per MMBTU. The current 10-year contract for fuel cell electricity is about 50% completed.

Successes and Challenges – The project is considered successful by its developers and owners. It was the first of its kind of project in CA – wastewater biogas injected into the natural gas pipeline system with natural gas extracted at other facilities to operate no emissions fuel cells. Also, the three fuels constitute the largest fuel cell project currently in the U.S. It is also economically viable at this time.

The principal challenges were interconnecting to the SDG&E gas pipeline. It was time-consuming and considered expensive ($1.9 MM). Also, as the wastewater treatment facility was in the California Coastal Zone, the time consuming permitting process through the California Coastal Commission was considered a challenge.

Case Study 7: Old River Road Dairy

The Old River Dairy digester facility is located at 20899 Old River Road, Bakersfield, CA and uses manure from an 8,000 head dairy cow farm. The biogas production system is a two cell, double-lined, lagoon digester. It is currently the largest in California at approximately 10 acres in areal extent. The biogas produced generates 2 MW of electricity via two 1-MW internal combustion gensets. The electric power is exported to the PG&E grid and the facility has a bilateral negotiated PPA with PG&E (price per kilowatt hour was not disclosed). The biogas production facility and power generation systems were developed, and are owned and operated by CalBio Energy (Visalia, CA) – the dairy farmer supplies the manure at no cost.

The covered lagoon digester technology was chosen, as it is the simplest and lowest construction and operation cost technology for dairy manure to biogas system available. The site was chosen due to a cooperative (and interested) large dairy farm owner.

The project owner would not disclose the project cost or financing arrangements.

Successes and Challenges – CalBio Energy considers The Old River Road project a success. It is economically viable and holds the position as the largest operating dairy farm biogas project in the state. It has also successfully demonstrated the covered lagoon digester type as the go-to technology for simple and lower cost operations.

Case Study 8: Van Warmerdam Dairy

The Van Warmerdam dairy digester is located at 12121 McKenzie Road, Galt, CA. It is a covered digester lagoon using high-density polyethylene membrane sheeting to contain, and store, the biogas produced from manure on this 1,000 head dairy cow farm.

Figure 23:Van Warmerdam Dairy (Courtesy: Mass Energy)

The digester lagoon has a total operational fluid volume of approximately 8 MM gallons. The facility can produce 600 kW via a single internal combustion engine genset. The digester's flexible sheeting cover enables biogas storage, allowing the ICE genset to run during peak power periods when prices paid for electricity are highest, and to store the biogas with prices are lower. This is part of the bilateral negotiated PPA with the

Sacramento Municipal Utility District (SMUD), in whose territory the diary digester is located. Revenues from electricity have been calculated at the estimated levelized PPA price of $0.146/kWh on the basis of estimated seasonal and time of day power generation

The site was chosen because the dairy farmer was willing to consider an energy conversion system using manure at his 1,000-cow dairy farm. As the dairy operations manure management was a water flush system, a covered lagoon anaerobic digester was selected as technology of choice. Similar to other dairy digesters, the dairy farmer only supplies the manure to the project, with a third-party developer, owner, and operated (Maas Energy Works, Inc. of Redding, CA). Although a previous attempt to install an AD system at the Van Warmerdam dairy failed, the current system owner entered into a grant agreement with SMUD in December 2011. Operation began in May 2013.

Project costs were $1.47MM. Additional development and financing costs brought the total project costs to $1.6MM. Project financing was a combination of grants and loans. The project was awarded a total of $881K in funding from SMUD, including $125K for the CEC and $756K from the U.S. Department of Energy. The project also secured a $900K construction loan from New Resource Bank.

Successes and Challenges – SMUD considers the Van Warmerdam dairy digester project to be very successful. It is one of the center points of the SMUD dairy digester program. The covered lagoon system works very well and the project is well operated. SMUD is particularly pleased that the digester system is a dispatchable source of electricity and can be quickly turned off and on to take advantage of peak pricing periods for electricity. By allowing operations primarily during peak pricing periods the project appears economically successful. The principal challenge with dairy digesters are capital costs and lower energy value of manure.

Case Study 9: Cabin Creek Biomass Facility Project

The proposed Cabin Creek Biomass Facility is to be located at the Placer County Eastern Regional Landfill near the intersection of California Highway 89 and Cabin Creek Road, approximately 4 miles south of Truckee, CA. It is a Placer County sponsored project, utilizing forest-sourced woody biomass waste from such sources as forest thinning activities to reduce wildfire potential in the Lake Tahoe region.

Figure 24: Schematic of Cabin Creek Facility

The County has chosen a private sector bioenergy project developer, Phoenix Energy (San Francisco, CA) to construct, own, and operate the facility. The facility is designed to be 2 MW of electricity generated by two internal combustion engine gensets fired by low Btu syngas produced from the gasification of woody biomass.

Up to 17,000 bones dry tons of woody biomass feedstock will be supplied to the facility. This feedstock would be solely woody biomass, derived from a variety of sources in the Lake Tahoe region, including forest-sourced material, such as hazardous fuels residuals (i.e., woody biomass material that pose a substantial fire threat to human or environmental health), forest thinning and harvest residuals (i.e., woody biomass generated from forest maintenance and restoration activities), and clean Wildland Urban Interface (WUI)-sourced waste materials from residential and commercial property defensible space clearing and property management activities.

Due to various complexities of the siting and project development, it has a relatively long history. A feasibility study and technology evaluation work for eastern Placer County forest-sourced wood waste to electricity project began in 2008. The project was awarded a U.S. Department of Energy development grant in 2009. A series of studies on siting, technology assessment, resource assessment, logistics, and emissions were conducted from 2009 to 2012. The Environmental Impact Report process was completed in 2013 and the Condition Use Permit was issued. 2013 to 2017 continued negotiations with local utility (Liberty Energy) for PPA that meets economics of the project.

The technology was chosen after an extensive woody biomass to electricity technology review and evaluation. It resulted in woody biomass gasification to electricity generation, with biochar as a marketable byproduct. The site was chosen because it is already the location of a closed County landfill and currently operating transfer/processing facility. And, as a Placer County sponsored project, the location is already County property.

The current estimated project cost is $13MM for 2 MW. Project Financing is currently proposed as a combination of public funding and grant dollars from County, state, and federal sources. County of Placer will likely finance the project through the California Infrastructure and Economic Development Bank.

Gasification of woody biomass results in a marketable byproduct – biochar. Biochar can be used for a range of applications as an agent for soil improvement, improved resource use efficiency, remediation and/or protection against particular environmental pollution, and as an avenue for greenhouse gas (GHG) mitigation. Biochar can be a very significant source of revenue for a woody biomass gasification facility, depending on biochar market prices. Approximately 10 to 15% of the total feedstock weight may be converted into biochar.

Successes and Challenges – Although the proposed facility currently lacks a PPA from the local IOU, there are many aspects of this project that would allow it to be successful (if and when it comes online). It would assist greatly in the reduction of open piling burning of forest thinnings in the Lake Tahoe Basin; the project is able to access significantly lower cost fuel due to arrangements between the County of Placer and the U.S. Forest Service; and it would promote further forest thinning to reduce catastrophic wildfire, particularly in the Lake Tahoe Basin.

The principal challenge continues to be getting a PPA from the local utility that meets the economic needs of the project.

Case Study 10: North Fork Community Power

North Fork Community Power is a 2 MW woody biomass gasification to electricity project currently under construction at an old sawmill site just east of the community of North Fork, in Madera County, CA. The project is being constructed by, and will be owned and operated by, North Fork Community Power LLC, with a partnership of Phoenix Energy (San Francisco, CA) and the North Fork Community Development Council, which owns the former sawmill property. The facility will generate the electricity via two 1-MW internal combustion engine gensets and export the electricity to PG&E under the BioMAT program.

The North Fork project is proposed to use up to 18,000 bone dry tons of woody biomass derived from a variety of sources in the North Fork and Madera County region of the Southern Sierra Nevada mountain and foothill range. Similar to the Cabin Creek project above, most of the woody biomass would be forest-sourced woody biomass waste from forest management activities. The facility may also use no more than 20% of non-forest woody biomass from urban and agricultural wood waste sources.

This project was initiated in 2011 with a feasibility and technology evaluation study and resource assessment analysis conducted, with technology and developer selected in 2012. In 2013 and 2014 the land use permitting and CEQA process was conducted and CUP issued in early 2014. In early 2015, the project received a $5MM grant for the CA Energy Commission Electric Program Investment Charge program. Since 2015, permitting, construction, and interconnect studies, are being conducted, with operations now scheduled to begin in mid-2018

The location was chosen because it was a former sawmill site with large areas of buildable real estate. It is also centrally located to take advantage of various forest thinning operations planned for the next decade. Furthermore, it is on land that is currently zoned industrial and the landowner is a partner in the LLC. The surrounding community is a very strong supporter of this project and its location.

The technology (GE Water and Power gasifier and GE Jenbacher Internal Combustion Engine gensets) was chosen because this equipment offered an investment grade warranty program.

The project cost is currently estimated at $14.5 MM, with $5MM from CEC EPIC grant, $1MM from New Market Tax Credits, and the remaining funds from private equity.

Project revenue will come from a BioMAT PPA that the facility will acquire. It is currently in the BioMAT Category 3 (forest-sourced biomass) PPA queue but has not yet asked for a PPA from PG&E. Also, the gasification byproduct biochar will also be sold on the open market and could result in significant revenues as well.

Successes and Challenges – Although the project was conceived in 2012, due to project financing difficulties, construction was delayed until late 2016 and is ongoing. Nonetheless, the project developers consider certain aspects of the project as an indication of tentative success. A major international company (General Electric) has both their small-scale biomass gasifier and internal combustion engine gensets (Jenbacher models) involved in the project and have issued performance warranties to North Fork Community Power. Also, the community support for the project is extremely high, along with support from the regulatory agencies.

Another challenge to the project has been the cost of interconnect. However, originally proposed in the PG&E System Impact Study at nearly $1.26MM, it has recently been lowered to less than $900K through meetings between the Governor’s Tree Mortality Task Force Bioenergy Working Group, the project developer, and the utility.

6.1.5 Community Biomass Lessons Learned

The TRC Team’s analysis of the case studies, along with the data and information collected from these Biomass case studies, revealed that California has established a vibrant market for biomass generation. However, the TRC Team did identify some issues that cause project delays and continue to be barriers for the industry. The TRC Team summaries them as follows:

- *Low Prices For Electricity:* The TRC Team’s case study analysis revealed that the cost of produced electricity from biomass projects is generally very expensive. These projects typically do contribute toward solving important societal and environmental problems such as organic waste diversion from landfills, reduction of methane and other GHG emissions, improving air quality by reducing open pile burning of woody biomass, reducing water quality impacts from dairy operations, and, reducing potential catastrophic wildfire (by use of forest thinnings in bioenergy facilities). The high costs of producing biomass electricity have been at odds with the relatively low wholesale prices that California utilities are generally willing to pay for purchasing it. This is a problem throughout the United States as well. A Wall Street Journal article[56] reported that low prices paid for biogas-based electricity are putting some agricultural digester projects on hold and others out of business. The article indicates, "construction of new U.S. farm digesters has slowed sharply over the past two years."

The low prices for electricity in California for community-scale bioenergy has, however, resulted in both technical and legislative changes to reach the necessary revenues to operate. For these facilities, the technical approach is to get their biogas into the transportation sector as Renewable Natural Gas (RNG), rather than produce electricity as the primary revenue generator. RNG used in vehicles can then take advantage of California's Low Carbon Fuel Standard and the federal Renewable Fuel Standard's transportation fuel credits as well. This can increase revenue significantly. Another technical approach is to the use electricity produced (some or all of it) on-site by the generator, offsetting the higher retail costs of electricity in California.

SB 1122, now the BioMAT program (see Section 6.1.3), was the legislative approach to increase energy prices in California. Through the BioMAT program, now several years in the making, bioenergy projects can finally produce electricity with positive financial success for the project. Two projects (both discussed in Sections 6.1.4 and Section 12) have already been issued higher price PPA, and there are several other dairy, agriculture, and forest biomass projects in the BioMAT queue, currently waiting for the prices to go even higher.

The on-site use of electricity or entry into a BioMAT PPA are the best approaches to rectify the low price of wholesale electricity in California (with the exception of some older projects or projects in non-IOU jurisdictions, which have PPA that were the subject of bilateral negotiation).

- *Complex project financing and lack of adequate financial resources:* The TRC Team's analysis of case studies revealed that most biomass projects require large upfront capital and are often financed by a combination of multiple financial resources from multiple sources. Nearly all the case study projects examined in this study also relied heavily on grant funding and utility incentives (such as SGIP) for their project development and capital expenditures. The lack of adequate financial resources for project development and capital expenditures are common impediments to community-scale bioenergy projects. Upcoming bioenergy projects also appear to rely on grant funding, as can be seen in the high number of applicants to the various California bioenergy grant-funding programs administered by the CEC, CalRecycle, and the Department of Food and Agriculture. As the bioenergy sector grows in California and the financial markets gain more confidence that such projects will work and be financially successful, hopefully, the need for grant funding to initiate projects will lessen.
- *Financial feasibility of project:* The TRC Team's analysis of case studies revealed that the financial feasibility of bioenergy projects is modeled or calculated in a myriad of ways, with many variables, and with a wide variety of assumptions for those variables. Getting the numbers "right" has been a challenge for bioenergy projects. Many of the case study projects had significant cost overruns, due in part to faulty financial modeling and inputs. Many of these projects utilize emerging technologies, or

[56] https://www.wsj.com/articles/energy-prices-steer-farmers-away-from-power-generators-1455814921

technologies that were previously used in Europe (particularly AD in Germany) where higher electricity prices allowed for more costly equipment. So, the actual costs of installation and operation in California can be difficult to predict properly.

The lesson here is that project developers must be conservative in their modeling of the financial feasibility of bioenergy projects, and include a large enough contingency in these models to ensure that cost overruns can be accounted for.

- *Obtaining adequate feedstock for AD projects:* The TRC Team's analysis of the case studies reveals that obtaining adequate feedstock for AD projects is critical. It is not enough to "build it and they will come" – contractual procurement of adequate amounts of feedstock, with the appropriate tipping fee should be in place prior to the commencement of construction, or at minimum firm letters of intent between feedstock suppliers and the facility should be in place. There have been AD projects, one of which was included in this study, where the feedstock necessary to run the facility at capacity was not fully identified -- let alone contracted for (or received a letter of intent). Therefore this facility has been unable to run at the capacity assumed in their financial model. Fortunately, several of the other AD projects in the study have procured the necessary amounts of feedstock before the projects began construction, so their projects run, or are expected to run, economically.
- *Receipt of adequate tipping fees in the case of AD projects:* The TRC Team's analysis of the AD case studies revealed that the receipt of adequate tipping fees in AD projects is a significant factor in the operation of an AD bioenergy project. Tipping fees add to the necessary amount of operating revenues needed by the AD facility. However, tipping fees at an AD facility are basically set by the local or regional cost of landfilling the food and organic wastes instead. This will likely change as legislative and regulatory mandates for the diversion of food and organic wastes from landfill tighten up over the next several years.
- *Procurement of economically priced feedstock in the case of woody biomass projects:* The TRC Team's analysis of the case studies revealed that the procurement of economically priced feedstock for woody biomass projects prior to construction is essential for project success. Unlike AD, woody biomass projects have to pay for feedstock, as opposed to receiving a tipping fee, due principally to the processing of the biomass and transportation to the user facility. In nearly all instances, the financial marketplace (equity investors, banks, etc.) will require the economically priced woody biomass feedstock to be secured by contract (preferably) or firm letter of intent prior to their commitment of funds.
- *Deciding which bioenergy technology to employ:* Deciding which bioenergy technology to employ is a critical concern, particularly given the predominance of certain waste feedstocks at the location of a bioenergy facility. Capital and operational costs can also come into play.

  For example, AD technology chosen should take into account whether or not the facility wants to process green waste as well as food waste. Wet fermentation AD does not work well with the woody component of green waste, nor with high straw content manures or animal bedding. If the available, or predominant, waste stream is high in green waste, or if it is desired to have green waste converted along with food waste, then the dry fermentation AD process should be selected.

  In the dairy digester sector, covered digester lagoons offer operational simplicity and lower costs than in-vessel digestion. In woody biomass conversion to energy, gasification systems that use minimal water, and have minimal wastewater discharge (if any at all), may be preferred over direct combustion, steam cycle electric generation systems because these systems can use significant amounts of water, and may have the need for wastewater evaporation ponds. Such ponds can add to costs and can require several acres of land depending on the size of the facility.

- *Utility interconnect process and costs:* The TRC Team's analysis of the case studies reveals that the utility interconnect process and costs can be very significant for community-scale bioenergy projects. These costs, particularly for the proposed woody biomass facilities located in remote forested areas, have added costs in the range of $1MM to $5MM to projects, which can equate to a 10 to 25% increase in overall project costs. The utility in which a project is located may also play a significant cost role. For example, the interconnect costs in the SMUD territory appear to be generally much lower than in the IOU territories.

  Given the current trend of high interconnect costs, the CPUC is conducting proceedings on how these costs can be better controlled. Also, the forest bioenergy projects, which are poised to come in under the BioMAT program, recently negotiated lowered interconnect costs for several proposed projects that have had System Impact Studies prepared, and interconnect costs proposed by the IOU.

- *Land use and environmental impact issues:* The TRC Team's analysis of case studies reveals that land use and environmental impact issues can potentially affect bioenergy projects in a wide variety of ways. Nearly all projects require some type of land use entitlement processing, even those that are sited on industrially zoned projects. Such processing in California invokes the California Environmental Quality Act (CEQA) and must be addressed by local land use agency. The CEQA process will take into account numerous environmental impact issue areas such as air quality impact, traffic, noise, etc.

  All of the projects examined for this study were involved in the CEQA process in some form. Given the location and siting of these projects (located on industrially zoned land, collocated with existing solid waste transfer and processing facilities, wastewater treatment facilities, or associated with agricultural enterprise such as dairy farm) the CEQA process has usually resulted in the issuance of a Negative Declaration or Mitigated Negative Declaration, which is a much less significant process than having a full Environmental Impact Report prepared (one of the woody biomass projects did opt for an EIR due to its location near the Lake Tahoe Basin).

  Community-scale bioenergy projects generally get Mitigated Negative Declarations under CEQA due to the size and scale of the projects. Air quality impacts are usually minimal as air pollutant emissions are limited by the size of the emission units. For example, a large AD project using food and organic waste (in the range of 200 tons a day) to generate biogas for electricity production might produce 2 to 3 MWs. Using state of the art internal combustion engine gensets, the emissions would be relatively low –even lower than the more stringent CA air districts significant environmental impact thresholds.

- *Disposition of byproduct and residuals from bioenergy conversion systems:* The TRC Team's analysis of case studies reveals that many of the bioenergy projects have residuals and byproducts, which must be managed in some way. In-vessel AD of food and organic waste produces both liquid and solid digestate. Ideally, these digestates can be used as a byproduct, rather than another form of waste. However, this is dependent on the chemical composition of the digestate and the marketing of the digestate to potential users. The AD projects examined for this report run across a wide spectrum for the disposition of their digestate. One project has identified end-users of the digestate for agricultural use, while another transports the solid digestate to composting operations while discharging the liquid digestate to the municipal sewer system. Another project must give away its digestate, pay for transport to agricultural end users, and sometimes even store the digestate while the facility looks for an end-user. This could be avoided by securing end-users prior to operations of the facility.

Diary digester residuals can generally be used on the dairy farm as fertilizer for feed growing areas of the farm. Co-digestion at wastewater treatment does result in additional bio-solids production, which can be handled in the same manner that the treatment plant is already using for its biosolids.

Biochar from gasification of woody biomass represents a potentially significant revenue source for such bioenergy projects, but only if market development for the utilization of biochar occurs. Currently, biochar is sold by a small gasification facility in the Central Valley on a spot market basis. The sale of biochar, and the revenue acquired, could be rolled into the total potential revenue stream of a woody biomass gasification to electricity project if a true market existed. Currently, investors and banks do not include biochar sales into the potential revenue stream because these facilities do not have biochar offtake contracts. However, the interest in biochar continues to be very high to project developers and biomass utilization advocates. There are many potential uses for biochar, from use as a soil amendment to water and wastewater treatment. The latter could be a significant market and many are interested in this large potential. Recently, the California Association of Sanitation Agencies was awarded a grant from the U.S. Forest Service to further examine and test biochar as a wastewater filtering agent.

7. Research Findings Summary

The TRC Team's research findings provide a valuable overview of important issues regarding the community solar market in California and across the country. The TRC Team addressed some of the research questions completely within the scope of this project while some questions require additional research and quantitative analysis beyond the qualitative scope of this study. Figure 25 provides an overall status completion status of each research question using the following rating criteria:

- Research Question Completely Addressed: (4) Rating used for all research questions that were adequately addressed by the TRC Team's primary and secondary research findings.
- Research Question Partially Addressed: (2) Rating used for all partially addressed research questions by the TRC Team's primary and secondary research findings. Developing complete answers to these questions was not possible due to the qualitative nature of this project. The TRC Team recommends performing primary research in Phase II to fully answer these questions.

Section 9 provides detailed description of the research findings and identified gaps for individual research questions.

RESEARCH QUESTION SCOPE	REPORT SECTIONS	OVERALL STATUS
1.1: Community solar regulations	5.4.1	4
1.2: Land use planning issues about community solar	5.4.2	2
1.3: Offsite community solar mandate examples	5.3	2
1.4: Examples of other community renewable regulations	6.1.1& 13	2
2.1: Future of community solar ownership	5.10	2
2.2: Tariffs and other financial mechanisms	5.6	2
2.3: Role of PACE loans	5.6.3	4
2.4: Planning process and incentives	14	2
2.5: Ownership variances due to project location	5.5	2
2.6: Length of Contract	5.5	2
2.7: Breach of Contract	5.5	4
2.8: Insurance Payments	5.5	2
2.9: Default to utility tariff	5.5 & 5.6	4
3.1: Role of the Utility	5.8.1	2

RESEARCH QUESTION SCOPE	REPORT SECTIONS	OVERALL STATUS
3.2: Tracking Methodologies	5.6	2
3.3: Community solar and ZNE	5.3	2
3.4: Community Solar Tariff adjustments for offsite systems	NA	2
4.1: Community biomass goals and successes	6.1.4 & 12	4
4.2: Biomass project success characteristics	6.1.4 & 12	4
4.3: Biomass permitting requirements	6.1.2 & 12	4
4.4: Biomass tariff frameworks	6.1.3 & 12	4

Figure 25: Overall Status Summary of Individual Research Questions

7.1 Summary of Next Steps to Address Research Gaps

Figure 26 identifies next steps for each of the 12 questions partially addressed by our research findings, and Section 10 provides details for the additional data needs and proposed research methods needed to address the gaps.

RESEARCH QUESTION	NEXT STEPS
1.2: Land use planning issues about community solar	Include Davis (U.C. & West Village) as a case study project (**Phase II, Objective 1**)
1.3: Offsite community solar mandate examples	Include Lancaster's implementation of community solar regulations as a case study project (**Phase II, Objective 1**)
1.4: Examples of other community renewable regulations	Scope individual research efforts (outside of Phase II) to investigate how other DER resources (storage, wind, CHP, etc.) can each support CA ZNE goals
2.1: Future of community solar ownership	Include an analysis in Phase II to assess community solar business models based on stakeholder-driven criteria that could support CA ZNE goals (**Phase II, Objective 1**)
2.2: Tariffs and other financial mechanisms	Include an analysis of the role of RECs, financing methods and the role of tariffs as the way to provide economic value and meet the ZNE goal requirements. (**Phase II, Objective 1**)
2.4: Planning process and incentives	Include a financial analysis in Phase II of potential compensation structures offered by the various business models investigated in the Business Model analysis (**Phase II, Objective 1**)

RESEARCH QUESTION	NEXT STEPS
2.5: Ownership variances due to project location	Test sensitivities to project location for compensation value in the Phase II Business Model analysis to test variances in community solar system ownership (**Phase II, Objective 1**)
2.6: Length of Contract	Test sensitivities of contract lengths on pricing models and subscription rates in Phase II Business Model analysis (**Phase II, Objective 1**)
2.8: Insurance Payments	Test sensitivities based on primary data in Phase II Business Model analysis to test the implication of insurance payments (**Phase II, Objective 1**)
3.1: Role of the Utility	Include stakeholder analysis in Phase II to include roles that utilities can play in supporting different community solar business models (**Phase II, Objective 1**)
3.2: Tracking Methodologies for Reconciling Offsite Production with Onsite Consumption	Include an exploration of existing and theoretical tracking methodologies for community solar in Phase II and align the results with each business model for inclusion in the Business Model analysis (**Phase II, Objective 3**)
3.3: Community solar and ZNE	Include an exploration of potential regulatory models under ZNE requirements that would enable the use of community solar to meet renewable energy needs (**Phase II, Objective 2**)
3.4: Community Solar Tariff adjustments for offsite systems	Conduct a focus group to evaluate potential tariff and accounting mechanisms for accommodating offsite systems (**Phase II, Objective 1**)

Figure 26: Summary of Research Next Steps

7.2 Phase II Research Scope Recommendations

The TRC Team summarized the research findings and identified the research gaps to provide recommendations for the scope of Phase II. Figure 26 includes the data needs, research methods, and next steps for addressing the following research objectives:

- Objective 1: Community Solar ZNE Business Models
  - *Case Study Examination:* The TRC Team provided readily-available information on the experiences of municipalities and organizations (e.g. U.C. Davis, Lancaster) and lessons learned from building departments regarding their experiences with the implementation of their community solar initiatives. A deeper dive into specific case studies from states that have had the most experience with community solar initiatives will be helpful to provide localized insights regarding barriers and challenges of implementation of community solar implications.
  - *Business Model Options Summary:* The TRC Team's research findings provide currently available information on community solar ownership models, value streams, tax issues and other business model details. However, this is a vast area of inquiry and individual components need to be analyzed in detail to inform a material policy direction. The TRC Team recommends that Phase II of this project leverage Phase I findings to examine existing as well as new and innovative business models relative to documented best practices and stakeholder-driven criteria for alignment with CA ZNE goals. Such models could seek to lower the subscription costs for customers and allow deeper penetration into the low and medium income market.
  - *Recommended Business Model(s):* The TRC Team recommends leveraging resultant findings from preceding Phase II tasks to identify the most appropriate community solar business model to achieve the ZNE goals.
- Objective 2: Community Solar ZNE Regulatory Model
  - As discussed in Section 5.3, there are fundamental community solar programmatic, regulatory and business model components that need to be addressed before it can be considered as a viable CEC ZNE compliance option. The objective of this task is to consider the most relevant compliance option for the viable business model(s) identified in Objective 1. The compliance options discussed in Section 5.3 are a starting point for this investigation. Important issues and details need to be addressed including:
    - Would community solar shares be an optional purchase at the time of house or building sale, or always bundled into the asset?
    - Role of RECs in meeting residential and commercial ZNE goals, including the Green-e Energy requirement to retire them on behalf of the customer. Clarifying ineligibility of community solar projects to meet ZNE goals if the developer retires or sells RECs either fully or partially for non-ZNE purposes such as RPS.
    - If an owner defaults on their mortgage, does the mortgage-holder then own a share of the system?
- Objective 3: Community Solar ZNE Tracking Methodologies and Grid Impacts
  - The TRC Team recommends examining available and theoretical energy accounting and tariff options (e.g. NEM, NNM, VOS, group billing etc.) to understand their impact on subscription rates, rate values and the overall business case for community solar. Critical to this examination is a detailed understanding of grid impacts. This research should also identify any market gaps that need

to be filled, and roles that utilities can play so community solar can become a viable option for ZNE implementation in California.

7.3 Individual Additional ZNE Research Roadmap Recommendations

The TRC Team recommends that the following research gaps are best suited for individual, ad-hoc research projects to be included in the next ZNE Research Roadmap:

Community Solar

- Develop a California-specific planning guide for community solar in the residential and commercial markets to support the ZNE goals, including tariff options for different ownership models.
- Examine the role of Community Choice Aggregation (CCA) on the future of ZNE and the community solar market in California.
- Investigate the role of disruptive Energy Cloud platforms[57] such as building-to-grid, transportation-to-grid, and transactive energy, i.e. blockchain, in advancing ZNE and community solar goals.
- Identify opportunities to more fully integrate community solar planning efforts into the utility distribution planning and integrated resource planning processes[58].

Community Biomass

- Explore barriers and challenges for the growth of the biomass market in California and identify steps needed to remove barriers and encourage the use of biomass to facilitate ZNE in the building sector.
- Investigate opportunities to streamline permitting and CEQA process for bioenergy projects.
- Explore the effect of the various CPUC proceedings currently underway on proposed bioenergy project's BioMAT process.

[57] Navigating the Energy Transformation, Navigant Consulting, Inc., August 2016: https://www.navigant.com/insights/energy/2016/navigating-the-energy-transformation

[58] Defining the Digital Future of Utilities, Navigant Consulting, Inc., April 2017: https://www.navigantresearch.com/research/defining-the-digital-future-of-utilities

8. Appendix A: Research Questions

8.1.1 Research Goal 1, Objective 1

Explore and characterize the current permitting requirements associated with siting and sizing community-scale systems

1.1 Community Solar regulations have passed in at least ten states. How is this being done? Are there any examples that are close fits? Any similar challenges being faced by local building departments? (DC and Boulder as examples?)

1.2. UC Davis modified its land use plan with solar in mind - is this being done elsewhere? Could this step help reduce the need for offsite renewables and/or help optimize the output of offsite renewables? Could it help create an easement or entitlement to associate renewables with a property for its lifetime?

1.3. Some local jurisdictions have mandated rooftop PV. Have any or could they mandate (or allow) offsite renewables tied to specific developments? Lancaster, CA is allowing contractors to meet their mandatory PV requirements using community kW averages for subdivisions. How are they tracking this? How is this working so far, and are developers using this community-scale option?

1.4. Are there examples of community renewable regulations for other types of renewable energy?

8.1.2 Research Goal 1, Objective 2

Review any current and proposed tariff frameworks that equitably allocate costs and generation to individual units, ownership, and financing

2.1. What does community solar ownership look like in 5-25 years?

2.2. Is a tariff the only way to link offsite renewables to a project, or are other viable mechanisms, such as bilateral PPAs possible as well?

2.3. What role do PACE loans and other financing options play in supporting the construction of community-scale renewables?

2.4. To fully optimize community-scale systems, basic electrical infrastructure will need to be planned and construction begun years before the first buildings are permitted and built. What types of planning processes and incentives could be established at the earliest possible development stage by local planning agencies to encourage community-scale systems?

2.4. Who owns community arrays or renewables? Who accrues the tax benefits (with ITC still in place investors with tax liability are best; ITC is currently available through the end of 2019).

2.5. Would ownership vary if renewables are on developer common property versus offsite?

2.6. What length of contract would be needed? 20 years? 30 years to match the lifetime of the building?

2.7. What's to prevent a developer from breaking a contract and selling the renewable energy elsewhere?

2.10. Who pays insurance on such contracts?

2.11 What measures could be put in place to ensure the residential off-takers continue to purchase the renewable energy rather than defaulting onto utility tariffs?

8.1.3 Research Goal 1, Objective 3

3.1. What role does utility have in tracking renewable kWh to a site?

3.2. Regardless of who is tasked with tracking, we must investigate plausible tracking methodologies for reconciling off-site production with on-site consumption. Investigate procedural and jurisdictional issues, apparent conflicts and solutions.

- For example, how will tracking methodologies treat community solar generation exports to the grid versus energy imports from the grid due to variances in weather, occupant behavior, etc. that were not captured in the modeling estimates that informed solar system sizing

3.3. How do the above variables interact and how can they be leveraged to forward ZNE goals? For example:

- 3.3.1. Do community-scale DER installations sited close to the substation of the development's feeder help to mitigate the grid impacts of the development's new load, while alleviating the need for locating DERs onsite to offset consumption?
- 3.3.2. How do active utility community solar tariffs, such as PG&E's "Green Option" community solar program, support achievement of the ZNE residential and commercial goals?

3.4. Should existing community solar tariffs be adjusted to account for the specific features of new residential construction? For example, should rates offered to customers reflect savings that can be achieved when the utility knows in advance the community will be served by on-site renewables?

8.1.4 Research Goal II, Objective 4

4.1. Were these projects successful/unsuccessful in terms of goals set out by the project administrator? Goals could include the amount of energy generated, efficiency, cost-effectiveness, emission reduction, etc.

4.2. What characteristics do successful projects exhibit (i.e. resources, location, scale, etc.)?

4.3. What permitting requirements were associated with these projects?

4.4. Were there any tariff frameworks associated with these projects?

9. Appendix B: Research Findings Summary Table

RESEARCH QUESTION SCOPE	RESEARCH FINDINGS	RESEARCH GAPS	REPORT SECTIONS	OVERALL STATUS
1.1: Community solar regulations	Understanding of community solar regulations in the U.S. and relevant examples	None	5.4.1	4
1.2: Land use planning issues about community solar	Research findings provide an overview and example of how Land use and zoning modifications can enable community solar	U.C. Davis case needs to be examined more closely	5.4.2	2
1.3: Offsite community solar mandate examples	Research findings provide an overview of regulatory mechanisms that allow offsite solar as compliance mechanisms for CA's ZNE goals	Lancaster's implementation of community solar regulations need to be examined more closely	5.3	2
1.4: Examples of other community renewable regulations	Research findings provide an overview of national wind market, examples of community storage and community biomass landscape in California	Due to the complexity and large variation between individual DER markets (storage, wind, CHP etc.), future research should focus solely on individual DER resources and formulate research goals and objectives specific to individual market needs	6.1.1& 13	2
2.1: Future of community solar ownership	Research findings include an overview of futuristic market potential community solar	Additional research is needed to conceptualize emerging ownership models that can be viable in the future	5.10	2

RESEARCH QUESTION SCOPE	RESEARCH FINDINGS	RESEARCH GAPS	REPORT SECTIONS	OVERALL STATUS
2.2: Tariffs and other financial mechanisms	Research findings include an overview of the main valuation streams for community solar projects but identify several issues that need additional analysis	Role of RECs and other compensation mechanisms versus traditional tariffs.	5.6	2
2.3: Role of PACE loans	Research findings indicate that PACE loans are not viable for this market	Future research could explore how existing PACE requirements could be changed to include community solar projects	5.6.3	4
2.4: Planning process and incentives	Research findings provide an overview of the role of planning agencies and examples of incentive best practices	Future research should examine the overarching program structure and alternate compensation mechanisms to remove barriers to further promote community solar adoption in California	14	2
2.5: Ownership variances due to project location	Research findings include a summary of key issues related to the location and siting of a community solar project, but do not address this question directly	Recommended for further investigation in Phase II scope	5.5	2
2.6: Length of Contract	Research findings include a summary of consumer preferences regarding contract length	Future research should explore the implication of contract length on pricing models and subscription rates	5.5	2
2.7: Breach of Contract	Research findings include summary of contractual details, consumer	None	5.5	4

RESEARCH QUESTION SCOPE	RESEARCH FINDINGS	RESEARCH GAPS	REPORT SECTIONS	OVERALL STATUS
	preferences, and examples to mitigate breach of contract			
2.8: Insurance Payments	Research findings provide an overview of insurance concerns and market realities	Recommended for further investigation in Phase II scope	5.5	2
2.9: Default to utility tariff	Research findings summarize main issues	None	5.5 & 5.6	4
3.1: Role of the Utility	Research findings include the importance of utility involvement in this market and how the role utilities should play to encourage community solar	Future research should include how the utility could play an enabling role in supporting community solar as a viable mechanism for ZNE implementation in California	5.8.1	2
3.2: Tracking Methodologies	Research findings provide a summary of available financial accounting mechanism for solar output	Recommended for further investigation in Phase II scope	5.6	2
3.3: Community solar and ZNE	Research findings provide a summary of the role of community solar and CA ZNE implementation goals	Future research should closely examine existing opportunities and barriers regarding the use of community solar and ZNE implementation and identify policy recommendations to further leverage community solar to meet ZNE goals	5.3	2

RESEARCH QUESTION SCOPE	RESEARCH FINDINGS	RESEARCH GAPS	REPORT SECTIONS	OVERALL STATUS
3.4: Community Solar Tariff adjustments for offsite systems	Research findings include available tariff and accounting mechanisms, but are unable to address this question	Recommended for further investigation in Phase II scope	NA	2
4.1: Community biomass goals and successes	Research findings provide an overview of project goals, successes, and challenges faced by the ten case studies examined by this project	Future research should explore: (1) whether the success characteristics and challenges that were unique to these case study projects are applicable to the larger biomass market; (2) what steps can be taken to encourage replication of successes and eliminate market barriers, and 3) what steps can be taken to encourage use of biomass to facilitate ZNE buildings	6.1.4 & 12	4
4.2: Biomass project success characteristics			6.1.4 & 12	4
4.3: Biomass permitting requirements	Research findings include a summary of all relevant regulations and permitting requirements in California	Future research should look into permit and CEQA process streamlining for bioenergy projects.	6.1.2 & 12	4
4.4: Biomass tariff frameworks	Research findings include a summary of all relevant financial frameworks in California	Future research should explore the effect of the various CPUC proceedings currently underway on proposed bioenergy project's BioMAT process.	6.1.3 & 12	4

10. Appendix C: Research Findings- Next Steps Summary

RESEARCH QUESTION	DATA NEED	RESEARCH METHODS	NEXT STEPS
1.2: Land use planning issues about community solar	Market data	Interview / Survey	Include Davis (U.C. & West Village) as a case study project (**Phase II, Objective 1**)
1.3: Offsite community solar mandate examples	Technical data Market data	Interview / Survey	Include Lancaster's implementation of community solar regulations as a case study project (**Phase II, Objective 1**)
1.4: Examples of other community renewable regulations	Technical data Market data	Interview / Survey Secondary Research	Scope individual research efforts (outside of Phase II) to investigate how other DER resources (storage, wind, CHP, etc.) can each support CA ZNE goals
2.1: Future of community solar ownership	Technical data Market data	Business Model Analysis	Include an analysis in Phase II to assess community solar business models based on stakeholder-driven criteria that could support CA ZNE goals (**Phase II, Objective 1**)
2.2: Tariffs and other financial mechanisms	Technical data Market data	Interview/Survey Financial Analysis Secondary Research	Include an analysis of the role of RECs, financing methods and the role of tariffs as the way to provide economic value and meet the ZNE goal requirements. (**Phase II, Objective 1**)
2.4: Planning process and incentives	Market data	Financial Analysis	Include a financial analysis in Phase II of potential compensation structures offered by the various business models investigated in the Business Model analysis (**Phase II, Objective 1**)

RESEARCH QUESTION	DATA NEED	RESEARCH METHODS	NEXT STEPS
2.5: Ownership variances due to project location	Technical data Market data	Interview / Survey Secondary Research	Test sensitivities to project location for compensation value in the Phase II Business Model analysis to test variances in community solar system ownership (**Phase II, Objective 1**)
2.6: Length of Contract	Market data	Interview / Survey	Test sensitivities of contract lengths on pricing models and subscription rates in Phase II Business Model analysis (**Phase II, Objective 1**)
2.8: Insurance Payments	Market data	Interview / Survey	Test sensitivities based on primary data in Phase II Business Model analysis to test the implication of insurance payments (**Phase II, Objective 1**)
3.1: Role of the Utility	Market data	Interview / Survey Secondary Research	Include stakeholder analysis in Phase II to include roles that utilities can play in supporting different community solar business models (**Phase II, Objective 1**)
3.2: Tracking Methodologies for Reconciling Offsite Production with Onsite Consumption	Technical data Market data	Interview / Survey Secondary Research	Include an exploration of existing and theoretical tracking methodologies for community solar in Phase II and align the results with each business model for inclusion in the Business Model analysis (**Phase II, Objective 3**)
3.3: Community solar and ZNE	Technical data Market data	Interview / Survey Secondary Research	Include an exploration of potential regulatory models under ZNE requirements that would enable the use of community solar to meet renewable energy needs (**Phase II, Objective 2**)

RESEARCH QUESTION	DATA NEED	RESEARCH METHODS	NEXT STEPS
3.4: Community Solar Tariff adjustments for offsite systems	Technical data Market data	Focus Groups Secondary Research	Conduct a focus group to evaluate potential tariff and accounting mechanisms for accommodating offsite systems (**Phase II, Objective 1**)

11. Appendix D: Community Solar Program Details By State

This table provides an update of nationwide community solar legislation as of August 2017 (Source: Shared Renewables HQ. Legislation Report 08.21.2017)

Type	State	Legislation Name	Program Enrollment Limit	Share Size Reqs.	Valuation of Benefits	Number of Participants	Treatment of Net Excess Generation	Eligible Customer Classes	Applicable Utilities	Geographic Scope
Enacted	CA	Virtual Net Metering for Multi-Tenant Buildings			Credited at retail rate	Minimum of 2		All customers in multi-tenant buildings	PG&E, SCE, SDG&E	Within the Multi-Tenant building hosting the solar system
Enacted	CA	Green Tariff Shared Renewables Program - SB 43		600 MW		Full CPUC approved value of shared renewable energy generation	No restrictions		All	PG&E, SCE, SDG&E
Enacted	CO	HB 1284 - Expand Scope of Shared Photovoltaic Facilities		2 MW	IOU purchase requirement capped at 6 MW/year from 2011-2013. After 2013, IOUs may choose to continue or not.	Credited at total aggregate retail rate minus	Minimum of 10 participants; 25 for installations larger than 500 kilowatts		All	Investor Owned Utilities
Enacted	CT	An Act Establishing a Shared Clean Energy Facility Pilot Program - SB 928	No more than 6 MW for the state	< 4 MW			At least 2		All	Investor Owned Utilities

Type	State	Legislation Name	Program Enrollment Limit	Share Size Reqs.	Valuation of Benefits	Number of Participants	Treatment of Net Excess Generation	Eligible Customer Classes	Applicable Utilities	Geographic Scope
Enacted	DE	Community Net Metering Provisions (Order 7946)	Subject to statewide net metering cap of 5% of Electric Supplier's aggregated customer monthly peak demand)	Subject to state net metering cap-statute encourages 2 MW)		For participants on the same distribution feeder as the Community Energy Facility, full retail rate. For customers, not on the same distribution feeder, SOS rate.	Minimum of 2		All	All Utilities
Enacted	HI	SB1050 / HB484: An Act Relating to Energy						All	All	
Enacted	ME	Net Energy Billing to Allow Shared Ownership	No limit specified (but the utility notification to the PUC is required if the cumulative capacity of net metered facilities reaches 1.0% of	660 kW for IOUs, 100 kW for muni's and co-ops		1:1 kWh credit	Up to 10 meters can be net metered against a single eligible facility.	Carried over as a kWh credit for 12 months. Credit expires after 1 year.	Any	Investor Owned Utilities

Type	State	Legislation Name	Program Enrollment Limit	Share Size Reqs.	Valuation of Benefits	Number of Participants	Treatment of Net Excess Generation	Eligible Customer Classes	Applicable Utilities	Geographic Scope
			peak demand).							
Enacted	MD	Electricity - Community Energy-Generating Facilities - Pilot Program - HB 1087 / SB 481		2 Mw	Not to exceed 200% of the subscriber's baseline usage	Credited through virtual net metering and a rate that is to be determined by the PSC	Minimum of 2		All	All
Enacted	MA	Virtual Net Metering as part of Massachusetts Green Communities Act (SB 2768)	All net metering capped at 6% of utility's peak load (3% allocated to government-owned systems, 3% to non-government systems)	2 MW (10 MW for government-owned systems)		Differs based on class of facility and type of customer. `	2 or more	Credits monetized (exact rate depends on facility class and customer type). Credits roll over indefinitely or may be transferre	All	All IOUs. Munis may offer net metering, but are not required to. (MA has no co-ops.)

Type	State	Legislation Name	Program Enrollment Limit	Share Size Reqs.	Valuation of Benefits	Number of Participants	Treatment of Net Excess Generation	Eligible Customer Classes	Applicable Utilities	Geographic Scope
								d to another customer.		
Enacted	MA	Neighborhood Net Metering (SB 2395)	Subject to statewide net metering cap of 6% of peak load. 3% of Utility Peak Load, 3% of peak load for municipal or governmental facilities			Credited at retail rate minus default service, transmission, transition charges	Minimum of 10 residential customers	Customers	Residential customer participation required in each facility, additional participation by other customer classes is permitted	All
Enacted	MN	Solar Energy Jobs Act (HF 729)	Unrestricted	1 MW	> 1 kW, average annual household demand	Credited at retail rate, with option for commission to adjust to a value-of-solar rate	Minimum of 5	Reconciled monthly as credit or payment	All	Xcel Energy, with voluntary participation by other IOUs.

Type	State	Legislation Name	Program Enrollment Limit	Share Size Reqs.	Valuation of Benefits	Number of Participants	Treatment of Net Excess Generation	Eligible Customer Classes	Applicable Utilities	Geographic Scope
Enacted	MN	Solar Energy Jobs Act (HF 729)	Unrestricted	1 MW	> 1 kW, average annual household demand	Credited at retail rate, with option for commission to adjust to a value-of-solar rate	Minimum of 5		All	Xcel Energy, with voluntary participation by other IOUs.
Enacted	NH	Group Net Metering		1MW		Full retail rate	Unrestricted	Annual true-up, excess paid at avoided cost / default service rate	All	All
Enacted	NY	PSC Order Establishing a Community DG Program		Projects are limited to 2 MW in size	Any individual members demanding greater than 25 kW may not constitute greater than 40% of the facility output in aggregate, with the exception of master-metered multi-unit buildings	Projects generally fall under the state's current net metering policy, and as such will be • Produce credits at full retail rate, based upon the project's rate classification	Minimum of 10	Rolled over monthly	All	All

Type	State	Legislation Name	Program Enrollment Limit	Share Size Reqs.	Valuation of Benefits	Number of Participants	Treatment of Net Excess Generation	Eligible Customer Classes	Applicable Utilities	Geographic Scope
Enacted	OR	House Bill 2941 - Relating to solar energy, creating new provisions								
Enacted	Vermont	Group Net Metering	Greater of 15% of utility's 1996 peak demand OR last year's peak demand (This cap applies to the state's overall net metering program.)	500 kW (2.2 MW on military property) with some exceptions		Credited at retail rate. HB 56 (2011) set additional incentives for solar net metering: Utilities must offer an extra credit of $0.20/kWh minus the highest residential rate. The customer receives the credit for 10 years.	Minimum of 2	Excess credits rolled over to next month; after 1 year, any remaining credit reverts to the utility.	All	All Utilities

Type	State	Legislation Name	Program Enrollment Limit	Share Size Reqs.	Valuation of Benefits	Number of Participants	Treatment of Net Excess Generation	Eligible Customer Classes	Applicable Utilities	Geographic Scope
Enacted	Washington	Community Renewables Enabling Act	Subject to a statewide net metering cap of 0.25% of a utility's peak demand during 1996. (Will increase to 0.5% in 2014)	75 kW		Direct payments to project owners starting at $0.30/kwh	No restriction	N/A	Projects must be located on community (government-owned) buildings, but all customer classes are eligible to participate	All
Enacted	Washington, DC	Community Renewables Energy Act	Unrestricted	5 MW		Credited at standard offer service rate for low voltage General Service customers (with no demand charges).	Minimum of 2		All	All

Type	State	Legislation Name	Program Enrollment Limit	Share Size Reqs.	Valuation of Benefits	Number of Participants	Treatment of Net Excess Generation	Eligible Customer Classes	Applicable Utilities	Geographic Scope
Proposed	New Mexico	Utility Act to Provide for Community Solar Facilities - SB 394			Credited at retail rate, utility required to purchase RECs at market rates	1 or more				
Proposed	Virginia	HB 1636 Net energy metering; program for community subscriber organizations		2 MW		On-bill credits from the energy generated by the facility	At least 5 subscribers	Applied to future bills		IOUs & electric co-ops
Proposed	Washington	Creating clean energy jobs in Washington state through renewable energy incentives - HB 1301	Subject to a statewide net metering cap of 0.25% of a utility's peak demand during 1996 (Will increase to 0.5% in 2014).	75 kW			no restriction	N/A	All	All

12. Appendix E: Biomass Case Study Interview Notes

12.1.1 Case Study 1: University of California, Davis (UCD) Renewable Energy Anaerobic Digester (READ)

Project Information

- Project Name: University of California, Davis (UCD) Renewable Energy Anaerobic Digester (READ)
- Location: 28068 County Road 98, Davis, CA 95616
- Owner: University of California, Davis (original owner was CleanWorld Partners (CWP), Gold River, CA)
- Developer: CleanWorld Partners. CWP continues to operate the facility, but UCD will become operator in the near future.
- Contact: Michael Fan, UCD Utilities Manager, (530) 752-7553, mmfan@ucdavis.edu
- Why was the technology and location chosen: The CWP anaerobic digester (AD) technology was originally developed by researchers at UCD (Dr. Ruihong Zhang, Department of Biological and Agricultural Engineering). UCD management wanted to showcase this new and innovative AD technology.
- Timeline: Construction began in spring 2013, with operations commencing in December 2013.
- Current Status: Facility is temporarily off-line, as a leaking tank requires repair. Repairs to be conducted 3rd Quarter 2017.

Inputs and Outputs

- Technology Type: High solids, wet fermentation, in-vessel anaerobic digestion
- Facility Capacity: Maximum capacity of 20,000 tons per year of feedstock input, with the biogas production to be supplemented by landfill gas from the collocated UCD Landfill.
- Feedstock(s): Agricultural organic waste, animal manure and bedding, food waste, and organic components of municipal solid waste, along with landfill gas. Facility receives 100% of food waste generated on the UCD campus. When CleanWorld Partners owned the facility, UCD paid them $30 per ton of food and organic waste received from UCD operations.
- Electricity amount: The current electrical generating capacity is 925 KW. However, due to lower than expected landfill gas volumes, this capacity is not currently being met.
- How electricity is produced: There are four 200 KW Capstone C200 biogas-fired micro turbines, and a 125 KW Organic Rankin Cycle engine genset using waste heat from the micro turbines.
- Interconnect: See Utility below.
- Plans for pipeline injection to supply power plants: No
- Other Products: It is estimated at full facility capacity that there would be 1,485 tons per year of liquid digestate and 3,835 tons of solid digestate
- Residuals Management: It was originally planned that the liquid digestate would be a revenue-generating commodity, i.e., a liquid fertilizer. However, it is currently being shipped off-site and mixed with composting materials. Solid digestate was also to be sold as a solid fertilizer not this has not been

realized to date. The solid digestate is currently air-dried on site and sent to a nearby landfill for disposal. There are plans to use the liquid and solid digestate in a collocated composting operation that is currently being reviewed by UCD for technical and economic feasibility.

- GHG emissions reduction calculated: Originally estimated reduction of GHG emissions by 13,500 tons per year when facility runs at full capacity.

Financing and Customer(s)

- Initial Project Cost: $8.6 MM (capital costs include permitting and interconnect)
- Project Financing: A complex arrangement of U.S. Department of Energy grant dollars ($2MM), a loan from the California Resources Recycling and Recovery Department (CalRecycle - $1MM), commercial loan from First Northern Bank ($5MM), and the remainder private equity. Plus, CleanWorld applied for the PG&E Self-Generation Incentive Program and has recently begun receiving SGIP funds. The total amount of funds received to date was not disclosed.
- Utility: UCD owns and operates its own electrical substation and currently contracts with the Western Area Power Administration (WAPA) for electricity and pays PG&E a wheeling fee for the use of their transmission lines. When CleanWorld owned the facility, UCD paid them $0.08 per kilowatt-hour.
- Other Customers (byproducts/residuals): None at this time
- Expansion Plans and current phase: None at this time

Project Contact Details:

- The interview was conducted on July 24, 2017, with Mr. Michael Fan, Utilities Manager for UCD. Mr. Fan has been associated with the READ project since its inception and has recently taken over operations of the facility (a result of the sale of the facility by CleanWorld Partners to UCD). Below are his responses to the principal interview questions.

Project successes and challenges

Although the facility is currently offline due to equipment issues, Mr. Fan stated that those issues will be repaired in the near future and operations will resume. Although there have been some other operational issues over the last 3 ½ years, Mr. Fan stated that he sees much more positive than negative outcomes. UCD is attempting to become as energy independent as possible and the AD system is a significant tool in that endeavor. He also sees the facility has a great R&D tool for UCD, and others in the AD energy conversion sector. With UCD ownership, there will be more R&D efforts involving the AD system. And, as the University is a public entity, these R&D efforts, along with the regular operations of the facility, will be available as public information. A significant challenge was that the animal manure and bedding feedstock does not appear to work well in the AD system. The higher cellulosic nature of this feedstock (straw and wood particles) does not allow for sufficient anaerobic digestion, and the solids from this feedstock plugged the AD system. It is now not used in the UCD AD system.

- **Successful Project Characteristics –** Mr. Fan stated that as a University endeavor, the facility's issues have actually enhanced their understanding of new and innovative AD technologies. The success has been that they have learned a lot over the last 3 ½ years.
- **Permitting** – Given that a high-efficiency flare and ultra-low emissions microturbine are employed in this facility, air quality permitting was very easy (air permits were obtained for the flare and microturbines. The facility also currently has an R&D notification solid waste permitting exemption from the Yolo County Environmental Health Department, which was also a relatively simple process. The facility will

need to apply for a solid waste permit by the end of 2017, but no significant issues are expected. As the project is on University land, no County of Yolo land use entitlement permitting was applicable.

- **Tariff Framework** – With the facility now owned by UCD, all electricity and feedstock payments are internal to UCD.

12.1.2 Case Study 2: Kompogas Anaerobic Digestion Plant

Project Information

- Project Name: Kompogas Anaerobic Digestion Plant
- Location: 4388 Old Santa Fe Road, San Luis Obispo, CA
- Owner: Hitachi Zosen INOVA
- Developer: Hitachi Zosen INOVA (100%)
- Contact: William Skinner, West Coast Sales Manager, (916) 246-9596, William.Skinner@hz-inova.com
- Why was the technology and location chosen: Waste Connections, the local franchise hauler is responsible for finding a final solution to the waste streams they haul. They put out an RFP looking for a solution, receiving two responses for composting and one for AD. Given that the cost was similar for each, they chose HZI given the advantages in GHG reduction, power to the local community, and compost for local agricultural.
- Timeline: Negotiations started in Aug 2015, permitting began in earnest in Jan 2016. Final permits issued Nov 2016 with construction beginning Dec 2016
- Current Status: Under construction, expected completion date April 2018, fully online Aug 2018.

Inputs and Outputs

- Technology Type: Kompogas Plug Flow Dry Anaerobic Digester
- Facility Capacity: 36,500 tons per year (100 tons per day)
- Feedstock(s): Greenwaste and source separated food waste from commercial generators (residential to be added later once residential food waste collection program operational in San Luis Obispo). There will be no processing of MSW on site, nor any de-packaging of food waste containers. Greenwaste to food waste ratio approximately 65 to 35% respectively. There is a tipping fee for waste received by the facility, however that fee is currently confidential.
- Electricity amount: 800 KW
- How electricity is produced: Electric produced via internal combustion engine genset. Engine excess heat used partly to heat digester system.
- Interconnect: Electricity to be sold to PG&E via a BioMAT Power Purchase Agreement (PPA) issued on 6/12/17. Contracted commercial operation date, 6/12/19. 20-year contract duration.
- Plans for pipeline injection to supply power plants: None
- Other Products: Solid digestate/compost and liquid digestate, all slated for use by local agricultural enterprises.
- Residuals Management: Liquid digestate used as is. Solid digestate is pressed and air-dried to reduce moisture content.
- GHG emissions reduction calculated: With an average electrical power production of approximately 800 kilowatts (kW), the proposed facility will convert up to 36,500 tons per year of food waste and urban green waste into 6.8 million kilowatt-hours (kWh) per year of renewable electricity, 13,000 tons per year

of compost, and up to 1.6 million gallons per year of liquid fertilizer. Further, the proposed project will reduce GHG emissions by 5,300 MT CO_2e per year

Financing and Customer(s)

- Initial Project Cost: $18 to $20 MM
- Project Financing: Initial project financing is principally internal financing from Hitachi Zosen, plus $4MM from the California Energy Commission Electric Program Investment Charge grant program (officially awarded 8/10/17) and another $4MM awarded by the CalRecycle Organics Grant Program and announced on 8/15/17. Owner will also receive the 30% Federal Investment Tax Credit as construction on the facility began before the sunset of that program at the end of 2016.
- Owner will also receive the 30% Federal Investment Tax Credit as construction on the facility began before the sunset of that program at the end of 2016
- Utility: PG&E via the BioMAT project. Facility to receive $0.1272 per kWhr.
- Other Customers (byproducts/residuals): Various local vineyards and other agricultural uses.
- Expansion Plans and current phase: No expansion plans

Project Contact Interview Questions Responses

The interview was conducted on July 12, 2017, with Mr. William Skinner, Utilities Manager for UCD. Mr. Skinner has been associated with the Kompogas project since its inception and was instrumental in its siting and development. Below are his responses to the principal interview questions.

- **Project success –** Although the facility is still under construction, it has all the features of a successful project to be. It is using a commercially-proven German technology which has been used at over 200 sites; a PPA with premium electricity prices is in place (a BioMAT PPA with PG&E); project is sited at a regional solid waste transfer and processing facility operated by a large waste collection company (Waste Connections, which services 6 million customers in the U.S. and Canada); a reported significant tipping fee; and offtake contracts for the liquid and solid digestate. The digester facility AD process can utilize both green waste and food waste, which is necessary for the region.

  The principal challenge to this project was securing the appropriate tipping fee. The feedstock supplier (Waste Connections) had to get the 9 jurisdictions (cities and county) to approve higher solid waste rates to ensure a financially viable tipping fee to the AD facility.

- **Successful Project Characteristics –** Mr. Skinner opined that given all the features of the project mentioned above that these covered items would make the project successful. All of these features must be addressed upfront for a project to be successful. Also, relationships between the project, the feedstock supplier, the responsible government agency (for solid waste), and community must be on good standing.
- **Permitting** – The Kompogas San Luis Obispo project required a Conditional Use Permit (CUP) from the County of San Luis Obispo Planning and Building Department. The CEQA process was conducted and the proposed facility received a Mitigated Negative Declaration for its CUP. There was some opposition to the project, as the opponents believed there would be odor issues. The facility developers, however, have designed the facility to minimize, or eliminate, any questionable odors by having the feedstock receiving inside of a building with negative pressure and a biofilter system for the air inside the receiving building. Air permits for the facility were obtained from the San Luis Obispo Air Quality Management

District. The facility will also require an in-vessel composting permit from the San Luis Obispo Local Enforcement Agency (Environmental Health Department).

- **Tariff Framework** – Facility has received PPA from PG&E under the BioMAT program on 6/12/17 with a contracted commercial operation date of 6/12/19 (facility will likely commence commercial operations prior to that date). Only one of two facilities in the state that currently has a BioMAT PPA (as of August 2017).

12.1.3 Case Study 3: Joint Water Pollution Control Plant (JWPCP)

Project Information

- Project Name: Joint Water Pollution Control Plant Co-Digestion
- Location: 24501 S. Figueroa Street, Carson, CA
- Owner: Los Angeles County Sanitation District
- Developer: Los Angeles County Sanitation District
- Contact: Mark McDannel, Manager, Energy Recovery Section, (562) 908-4288 X2442, mmcdannel@lacsd.org
- Why were the technology and location chosen: Facility consists of numerous large wastewater digesters, which would allow for co-digestion with food waste and not adversely affect wastewater treatment operations.
- Timeline: In 2012, LACSD began bench-scale tests with slurried food waste. In February 2014 LACSD commenced multi-year demonstration program, using slurried food waste obtain in agreement with Waste Management (WM). Up to 84 wet tons per day (WTPD) to be used in the demonstration program.
- Current Status: The demonstration program is currently underway with approximately 62 WTPD being used in one digester at the Joint Water Pollution Control Plant (JWPCP).

Inputs and Outputs

- Technology Type: Co-digestion of slurried food waste in wastewater treatment system
- Facility Capacity: The JWPCP wastewater treatment facility generates 18 to 20 MW with the processing of a daily average of 280 million gallons/day of wastewater from a service area of 3.5 million people. The facility digesters produce about 5,000 standard cubic feet per minutes of biogas. The biogas is then cleaned, compressed, and chilled to fuel three gas turbines and one steam cycle turbine.
- Feedstock(s): Wastewater and slurried food waste
- Electricity amount: The JWPCP generates up to 20 MW of electricity, which is used to power the treatment plant. There is export of 200 KW to the grid so the facility can "island" if necessary and be independent of the grid in case of grid problems. Currently, the demonstration project volume of food waste contributes approximately 700 KW to the treatment plant power system. This 700 KW is exported to the grid via a SoCal Edison interconnection to the CalISO system at real-time prices.
- How is electricity produced: Gas turbines and steam cycle turbine
- Interconnect: Project electricity is exported to CalISO via a SoCal Edison interconnect.
- Plans for pipeline injection to supply power plants: Yes, LACSD is evaluating pipeline injection potential for either electricity or transportation fuel production.
- Other Products: The facility will be expanding its use of food waste into the facility. It is proposed by summer 2017 that up to 335 TPD of food waste will be utilized. Much of this additional biogas production will be diverted to Renewable Compressed Natural Gas (RCNG) and distributed at the facilities RCNG fueling station (station to also be expanded to accommodate this additional RCNG).

- Residuals Management: Biosolids are removed from the facility and land applied.
- GHG emissions reduction calculated: None available as yet.

Financing and Customer(s)

- Initial Project Cost: Demonstration program, no costs given. Expanding system to process food (off-site at the Puente Hills Materials Recovery Facility), $1.8 MM. To upgrade systems at the JWPCP for the next phase (up to 335 TPD of food waste), $5MM. To construct new on-site food waste receiving system for the additional digesters needed for expansion, $7MM.
- Project Financing: Primarily financed out of LACSD solid waste management revenues. Received $2MM grant from CEC for food waste processing system. Additionally, the LACSD was awarded $4MM from CalRecycle's Organics Grant Program in August 2017.
- Utility: Southern California Edison (SCE)
- Other Customers (byproducts/residuals): None
- Expansion Plans and current phase: Food waste conversion to electricity demonstration program is considered Phase 0. Upgrade to 335 TPD of food waste per day for RCNG and electricity is considered Phase 1 and is scheduled to be in place by end of 2017. Phase 2, which may be pipeline injection of gas, possible electricity export to grid via BioMAT program, hydrogen production, or other possibilities to be evaluated by the LACSD.

Project Contact Interview Questions Responses

The interview was conducted on June 28, 2017, with Mr. Mark McDannel, Manager, Energy Recovery Section, Los Angeles County Sanitation Districts. Mr. McDannel leads the team at LACSD for the food waste co-digestion project at the JWPCP in Carson. Below are his responses to the principal interview questions.

- **Project success –** Mr. McDannel considers the project a success so far. The initial demonstration phase showed that the introduction of food waste into the wastewater digesters did not create any problems, nor did it impact the treatment plant's number one goal – reliability of the treatment plant to conduct its main mission of wastewater treatment. When the co-digestion of food waste was proposed the treatment plant operators expressed reservations, so the demonstration phase was initiated and which has been deemed successful with minimal impact of the wastewater treatment process. The next phase (over 300 tons per day of food waste) is being implemented.
- **Successful Project Characteristics –** Mr. McDannel stated there are two principal characteristics which are showing that the co-digestion project is successful – minimal impact on the wastewater treatment plant and its principal goal to treat municipal wastewater; and it is assisting LACSD member agencies in meeting AB 1826 requirements for recycling commercial food waste.
- **Permitting** – Co-digestion of food waste at a publicly owned wastewater treatment is exempt from solid waste permitting. However, the JWPCP co-digestion has prepared (and implemented) Best Management Practices (BMPs) for the County of Los Angeles Local Enforcement Agency (Department of Public Health). The treatment plant operations are also currently permitted by the California Regional Water Quality Control Board (Los Angeles) National Pollution Discharge Elimination System permit and Waste Discharge Requirements.
- **Tariff Framework** – The JWPCP facility uses nearly all the power that is produced at the facility for itself. A small portion of the electric power is exported via So Cal Edison interconnect to CalISO and is sold at the real-time price of electricity.

12.1.4 Case Study 4: East Bay Municipal Utility District (EBMUD) Main Wastewater Treatment Plant, Oakland, CA.

Project Information

- Project Name: East Bay Municipal Utility District (EBMUD) Resource Recovery
- Location: EBMUD Main Wastewater Treatment Plant, 2020 Wake Ave., Oakland, CA
- Owner: EBMUD
- Developer: EBMUD
- Contact: John Hake, Resource Recovery Program Manager, (510) 287-1542, john.hake@ebmud.com
- Why was the technology and location chosen: Facility consists of numerous large wastewater digesters, which would allow for co-digestion with food waste and not adversely affect wastewater treatment operations. Originally developed at current site due to a number of food processing facilities in the region.
- Timeline: Receipt of liquid organic wastes by truck (primarily septage and FOG – fats, oils, and greases) began in 2002. The system was upgraded in 2004 to accept slurried food and organic waste with paddle finisher installed to remove contamination. In 2014 additional upgrades installed, such as blend tank receiving system.
- Current Status: Currently operating with an average input of 200,000 gallons a day of high strength organic and food waste.

Inputs and Outputs

- Technology Type: Co-digestion of slurried food waste in wastewater treatment system
- Facility Capacity: Average daily input of 200,000 gallons of high strength organic and food waste.
- Feedstock(s): Primarily source separated organic and food wastes, plus fats, oils, and grease (FOG)
- Electricity amount: Approximately 3.5 MW attributable to organic/food waste with another 2.5 MW from wastewater treatment. A 4.5 MW gas turbine was added in 2011, allowing the facility to become an exporter of electricity. This surplus power is sold to the neighboring Port of Oakland by wheeling through PG&E.
- How is electricity produced: Three internal combustion engine gensets of 2.2 MW each.
- Interconnect: PG&E is the wheeling interconnect.
- Plans for pipeline injection to supply power plants: None at this time
- Other Products: None
- Residuals Management: Biosolids are collected and transported off-site for use as alternative daily cover at landfills or land is applied. Both are done at cost to the facility.
- GHG emissions reduction calculated: Not disclosed

Financing and Customer(s)

- Initial Project Cost: Since 2002, approximately $21 MM has been spent for the organic waste collection, processing, and storage components of the facility.

- Project Financing: EBMUD internal financing. Income from waste hauled to the plant's digesters is about $8 million. Tipping fees range from 3 to 11 cents per gallon for liquids; food wastes, which require much more handling, have tipping fees from $30 to $65 per ton.
- Utility: PG&E
- Other Customers (byproducts/residuals): None sold
- Expansion Plans and current phase: EBMUD is following the need for additional food/organic waste landfill diversion needs per AB 1826 (mandated commercial organic waste recycling) and SB 1383 (reduction of short-lived climate pollutants).

Project Contact Interview Questions Responses

The interview was conducted on June 26, 2017, with Mr. John Hake, Resource Recovery Manager for the EBMUD Resource Recovery system Mr. Hake has been associated with the organics and food waste conversion project since its inception in the early 2000's. Below are his responses to the principal interview questions.

- **Project success –** Mr. Hake considers the resource recovery system at EBMUD to be very successful. The co-digestion of the organics and food waste in EBMUD wastewater digesters does not significantly impact the wastewater treatment operations, and allow the entire plant to be electricity self-sufficient. Plus, expansion over the years and growth in the amount of organics and food waste being converted to electricity, allow EBMUD to export electricity to the nearby Port of Oakland and adding to its revenues.
- **Successful Project Characteristics –** The ability to take on some risk to get a project up and running, and being adaptive as conditions change or are modified by economics and/or regulations.
- **Permitting** – Co-digestion of organic and food waste in a publicly owned wastewater treatment facility is exempt. The co-digestion activities are covered by the facility's National Pollution Discharge Elimination System permit and the Waste Discharge Requirements.
- **Tariff Framework** – Facility averages 130% of its on-site electricity needs. Excess electricity is wheeled via PG&E to the Port of Oakland.

12.1.5 Case Study 5: Zero Waste Anaerobic Digestion Facility, San Jose

Project Information

- Project Name: Zero Waste Anaerobic Digestion Facility, San Jose
- Location: 685 Los Esteros Rd, San Jose, CA 95134
- Owner: Zero Waste Energy Development, LLC
- Developer: Zero Waste Energy Development, LLC
- Contact: Greg Ryan, General Manager, (408) 316-1095, greg@zankerrecycling.com
- Why was the technology and location chosen: Numerous AD technologies from Germany were evaluated, with the selected technology being the most tolerant and flexible for the conversion of organic/food waste and green waste. The site was selected due to industrial zoning and related solid waste processing facilities adjacent and nearby.
- Timeline: Commercial operations began in November 2013
- Current Status: Operating

Inputs and Outputs

- Technology Type: Dry Fermentation Anaerobic Digestion
- Facility Capacity: 90,000 tons per year (TPY). Currently processing 65,000 TPY.
- Feedstock(s): Processed municipal solid waste (processed by Republic Services at their nearby Newby Island Resource Recovery Park) and green waste (such as landscaping trimmings, grass clippings, etc.) from City of Palo Alto. Feedstock mix approximately 15 to 20% green waste, with 80 to 85% organic waste.
- Electricity amount: 1.6 KW of electricity exported to PG&E grid.
- How electricity is produced: Two 800 KW Caterpillar Internal Combustion Engine gensets.
- Interconnect: Electricity is sold to PG&E via a BioMAT Power Purchase Agreement (PPA - issued 11/4/16). Commercial operation date, 12/7/16. 10-year contract duration. Interconnection cost was $750K.
- Plans for pipeline injection to supply power plants: No
- Other Products: AD solid digestate transported offsite for use in composting operation.
- Residuals Management: Liquid digestate currently discharged (10,000 to 15,000 gallons per day) to City of San Jose sewer system
- GHG emissions reduction calculated: Not disclosed

Financing and Customer(s)

- Initial Project Cost: $55MM
- Project Financing: $39 MM in bonds from the California Pollution Control Financing Authority, $12 MM in cash from the development company, and $4 MM from member companies.

- Utility: PG&E via the BioMAT project. Facility to receive $0.1272 per kWhr. The facility also receives tipping fee for accepting waste averaging $105 per ton.
- Other Customers (byproducts/residuals): Solid digestate is sold to Z Best Composting in Gilroy, CA
- Expansion Plans and current phase: None at this time

Project Contact Interview Questions Responses

The interview was conducted on July 10, 2017, with Mr. Greg Ryan, General Manager, San Jose Zero Waste AD Facility. Mr. Ryan has been associated with the San Jose Zero Waste project since its inception and was instrumental in its development. Below are his responses to the principal interview questions.

- **Project success –** Technically the AD project is a success as it demonstrating a new technology that converts both low moisture green waste and high moisture organic/food wastes, which is assisting the City of San Jose in meeting its goal of increasing landfill diversion (Goal #5 of the San Jose Green Vision Plan. It is also allowing San Jose and other communities to address the requirements of AB 1826 with recycling of commercial generated organic and food wastes. However, Mr. Ryan did state the facility is not meeting with financial goals. As the first of its kind dry AD system, and imported from Germany, there were significant cost overruns. Plus the organic and food waste delivered by Republic Services is generally contaminated and requires additional handling (which drives up costs to Zero Waste). Zero Waste continues to have a difficult time getting clean feedstock from Republic.
- **Successful Project Characteristics –** As a private sector enterprise, meeting the financial goals is necessary to consider an AD project successful.
- **Permitting** – As the project commenced operations before the promulgation of the CalRecycle in-vessel AD regulations, the San Jose facility obtained a full Solid Waste Facility Permit (Facility Number 43-AN-0033) from CalRecycle as a composting facility (non in-vessel composting operations also occurred at the facility site). The emergency flare, biogas cleanup, ICE gensets, and biofilters all have permits from the Bay Area AQMD.
- **Tariff Framework** – Facility has received PPA from PG&E under the BioMAT program on 11/4/16 and commercial operation date using the PPA was 12/7/16. It is only one of two facilities in the state that currently have a BioMAT PPA (as of August 2017).

12.1.6 Case Study 6: Point Loma Beneficial Use of Digester Gas, San Diego, CA

Project Information

- Project Name: Point Loma Beneficial Use of Digester Gas
- Location: 1902 Gatchell Rd, San Diego, CA 9210
- Owner: Biofuels Energy, LLC
- Developer: Biofuels Energy, LLC
- Contact: Frank Mazanec, Managing Director, (760) 420-9600, fmazaniec@biofuelsenergyllc.com
- Why was the technology and location chosen: City of San Diego issued a Request for Qualifications to use the Point Loma Wastewater Treatment Plant digester gas for beneficial use.
- Timeline: City of San Diego issued RFQ in January 2007, with biogas agreements and project financing conducted from 2007 to 2010. Construction began in December 2010 with the biogas collection, cleanup, and pipeline injection construction, along with installation of fuel cells at University of California, San Diego, and City of San Diego South Bay Water Reclamation Plant completed late 2011. Commercial operation begun January 2012
- Current Status: Operational, with fuel cells receiving pipeline gas for conversion to electricity.

Inputs and Outputs

- Technology Type: Wastewater digester gas and natural gas fuel cells
- Facility Capacity: As this facility is anaerobic digestion of municipal wastewater only, the facility operator calculates their annual capacity as 225,000 MMBTU per year
- Feedstock(s): Wastewater only.
- Electricity amount: Biogas produced and injected into natural gas pipeline is utilized by two fuel cells, 2.8 MW at UCSD, and 1.4 MW at City of San Diego South Bay Water Reclamation Plant. Currently largest fuel cell project in U.S.
- How is electricity produced: Fuel cells
- Interconnect: San Diego Gas and Electric natural gas pipeline. Interconnect cost $1.99 MM
- Plans for pipeline injection to supply power plants: This is current arrangement
- Other Products: None
- Residuals Management: Bio-solids are removed from wastewater treatment facility for land application.
- GHG emissions reduction calculated: None calculated as yet.

Financing and Customer(s)

- Initial Project Cost: $45 MM
- Project Financing: New Energy Capital provided equity capital, plus New Market Tax Credits and Self-Generation Incentive Program payments ($14MM). Grants, credits, and incentives total $33MM.
- Utility: San Diego Gas and Electric (SDG&E)

- Other Customers (byproducts/residuals): None
- Expansion Plans and current phase: None contemplated at this time. Potential to move from supplying biogas for electricity to supplying biogas to transportation fuels. Currently receiving about $12 MMBTU for fuel cell conversion to electricity. The market for transportation fuels currently in high $20's per MMBTU. Current 10-year contract for fuel cell electricity is about half completed.

Project Contact Interview Questions Responses

The interview was conducted on June 29, 2017, with Mr. Frank Mazanec, Managing Director for the Point Loma biogas project. Mr. Fan has been associated with the project since its inception and was instrumental in its development at both the wastewater treatment plant and the fuel cell system locations. Below are his responses to the principal interview questions.

- **Project success –** The project is considered successful by its developers and owners. It was the first of its kind of project in CA – wastewater biogas injected into the natural gas pipeline system with natural gas extracted at other facilities to operate no emissions fuel cells. Also the three fuels constitute the largest fuel cell project currently in the U.S. It is also economically viable at this time.
- **Successful Project Characteristics –** Having an economically viable project is the most important successful project characteristic.
- **Permitting** – The fuel cells are pre-certified for no emissions by the California Air Resources Board. An air permit from the San Diego AQMD was necessary for an emergency flare for the project. The biggest problematic permit was the Coastal Development Permit from the CA Coastal Commission.
- **Tariff Framework** – The biogas facility receives payment from the fuel cell facilities based upon gas usage at the MMBtu price point. Currently, for biogas to electricity, it is about $12 per MMBtu equivalent.

12.1.7 Bioenergy Case Study 7: Old River Road Diary, Bakersfield, CA

Project Information

- Project Name: Old River Road Diary
- Location: 20899 Old River Road, Bakersfield, CA
- Owner: Special Purpose LLC (interviewee would not disclose full name)
- Developer: CalBio Energy
- Contact: Neil Black, President, CalBio Energy, (559) 334-4213, nblack@calbioenergy.com
- Why was the technology and location chosen: Technology was chosen, as it is the simplest dairy manure to biogas system available. The site was chosen due to a cooperative (and interested) dairy farm owner.
- Timeline: Began operations in Fall 2013
- Current Status: Operational

Inputs and Outputs

- Technology Type: Two cell, double-line lagoon digester – currently largest in the state. Approximately 10 acres in area (as measured on aerial photograph).
- Facility Capacity: Not disclosed
- Feedstock(s): Manure from 8,000 head dairy cow farm
- Electricity amount: 2 MW exported to electric grid
- How electricity is produce: Two 1-MW internal combustion engine gensets
- Interconnect: PG&E
- Plans for pipeline injection to supply power plants: Not disclosed
- Other Products: None
- Residuals Management: Not disclosed
- GHG emissions reduction calculated: Not yet calculated

Financing and Customer(s)

- Initial Project Cost: Would not disclose
- Project Financing: Would not disclose
- Utility: PG&E. PPA is a bilateral negotiated contract
- Other Customers (byproducts/residuals): None
- Expansion Plans and current phase: None

Project Contact Interview Questions Responses

The interview was conducted on June 29, 2017, with Mr. Neil Black, President of CalBio Energy. Mr. Black and his CalBio team developed, built, and operate the Old River Road Dairy biogas project. Below are his responses to the principal interview questions. It should be noted that Mr. Black would not disclose several project features.

- **Project success –** CalBio Energy considers The Old River Road project a success. It is economically viable and holds the position as the largest operating dairy farm biogas project in the state. It has also successfully demonstrated the covered lagoon digester type as the go-to technology for simple and lower cost operations.
- **Successful Project Characteristics –** CalBio Energy considers relatively simple technologies such as covered lagoons will make for successful projects.
- **Permitting** – Emergency flare and internal combustion engine gensets required permits from San Joaquin Valley Air Pollution Control District. The CA Regional Water Quality Control Board (Central Valley) also regulates dairy digesters and dairy farms via General Orders to which owners and operators can acquire.
- **Tariff Framework** – Facility negotiated a bilateral electricity purchase contract from PG&E. Price per kWh was not disclosed.

12.1.8 Bioenergy Case Study 8: Van Warmerdam Dairy Digester, Galt, CA

Project Information

- Project Name: Van Warmerdam Dairy Digester
- Location: 12121 McKenzie Rd, Galt, CA
- Owner: Maas Energy Works, Inc.
- Developer: Maas Energy Works, Inc.
- Contact: Val Tiangco, Biomass Program Manager, Sacramento Municipal Utility District (SMUD), (916) 732-6795, vtiangc@smud.org
- Why was the technology and location chosen: The dairy farmer was willing to consider an energy conversion system using manure at his 1,000-cow dairy farm. As the dairy operations manure management was a water flush system, a covered lagoon anaerobic digester was selected as the technology of choice.
- Timeline: Although a previous attempt to install an AD system at the dairy failed, the current system owner entered into a grant agreement with SMUD in December 2011. Permitting occurred during 2012, with construction beginning in January 2013, with operations beginning in late May 2013.
- Current Status: Operational

Inputs and Outputs

- Technology Type: A covered earthen lagoon using high-density polyethylene membrane sheeting. The flexible sheeting allows for biogas storage.
- Facility Capacity: The covered lagoon has a total operational fluid volume of approximately 8MM gallons.
- Feedstock(s): Dairy cow manure
- Electricity amount: 600 KW for export to SMUD electric grid.
- How electricity is produced: A single 600 KW internal combustion engine genset manufactured by Martin Machinery. The digester's flexible sheeting cover enables biogas storage, allowing the ICE genset to run during peak power periods when prices paid for electricity are highest, and to store the biogas with prices are lower.
- Interconnect: Electric power is exported the SMUD, with a total estimated annual power of 1,800 MWh.
- Plans for pipeline injection to supply power plants: None
- Other Products: None
- Residuals Management: The effluent from the digester is used a liquid fertilizer for growing vegetation on the dairy farm that the dairy cows feed upon. The solids from the digester are air-dried and used in bedding for the dairy cows.
- GHG emissions reduction calculated: SMUD has estimated the total annual GHG emissions reductions to 7,839 metric tons/CO2 equivalent (MT/CO_2e).

Financing and Customer(s)

- Initial Project Cost: Total construction costs were $1.47MM. Additional development and financing costs brought the total project costs to $1.6MM.
- Project Financing: The project was award a total of $881K in funding from SMUD, including $125K for the CA Energy Commission and $756K from the U.S. Department of Energy. The project also secured a $900K construction loan from New Resource Bank.
- Utility: Sacramento Municipal Utility District (SMUD). Revenues from electricity have been calculated at the estimated levelized PPA price of $0.146/kWh on the basis of estimated seasonal and time of day power generation. PPA is for 20 years
- Other Customers (byproducts/residuals): None
- Expansion Plans and current phase: There exists the potential for nearby dairy to send produced biogas to the Van Warmerdam system.

Project Contact Interview Questions Responses

The interview was conducted on June 21, 2017, with Mr. Valentino Tiangco, Biomass Program Manager at SMUD. Mr. Tiangco has been associated with the Van Warmerdam dairy digester project since its inception and was instrumental in finding and supplying the funds to construct the project. Below are his responses to the principal interview questions.

- Project success – Mr. Tiangco considers the Van Warmerdam dairy digester project to be very successful. It is one of the center points of the SMUD dairy digester program. The covered lagoon system works very well and the project is well operated by Maas Energy. SMUD is particularly pleased that the digester system is a dispatchable source of electricity and can be quickly turned off and on to take advantage of peak pricing periods for electricity. By allowing operations primarily during peak pricing periods the project appears economically successful.
- Successful Project Characteristics – Similar to other covered lagoon AD systems the relatively simplicity of the systems helps to create a successful project. It also has the ability to be dispatchable which can take advantage of favorable pricing.

  SMUD also reports the significant drivers for economic success of covered lagoon digesters for widespread deployment include the following:
  - Increased carbon value from methane destruction
  - Reduction in capital costs
  - Reduction in operating expenses
- Permitting – Permits for the Sacramento Metropolitan AQMD were needed for the internal combustion engine gensets, the biogas cleanup system, and the emergency flare. The CA Regional Water Quality Control Board (Central Valley) also regulates dairy digesters and dairy farms via General Orders to which owners and operators can acquire.
- Tariff Framework – Facility has a 20-year PPA with SMUD commencing in 2014. It allows for the dispatchability of the system to take advantages of peak prices where up to $0.32 per kWh can be paid. This allows for an overall levelized cost of $0.14 to $0.15 per kWh.

12.1.9 Case Study 9: Cabin Creek Biomass Facility Project, Truckee, CA

Project Information

- Project Name: Cabin Creek Biomass Facility Project
- Location: Highway 89 and Cabin Creek Road, Truckee, CA
- Owner: Tahoe Regional Power Company, LLC
- Developer: Phoenix Energy
- Contact: Brett Storey, Principal Management Analyst, Environmental Utilities, Placer County, (530) 745-3011, bstorey@placer.ca.gov
- Why was the technology and location chosen: The technology chosen was the result of an extensive woody biomass to electricity technology review and evaluation. It resulted in woody biomass gasification to electricity generation, with biochar as a marketable byproduct. The site was chosen, as it is already the location of a closed landfill and currently operating transfer/processing facility. And, as a Placer County sponsored project, the location is already County property.
- Timeline: Feasibility study and technology evaluation work for eastern Placer County forest-sourced wood waste to electricity project began in 2008. The County of Placer was awarded U.S. Department of Energy development grant in 2009. Series of studies on siting, technology assessment, resource assessment, logistics, and emissions conducted from 2009 to 2012. Environmental Impact Report process completed 2013 and Conditional Use Permit issued. 2013 to 2017 continued negotiations with local utility (Liberty) for PPA that meets economics of the project.
- Current Status: Still seeking PPA from local utility. As a bilateral negotiation, the agreed to electricity price has not yet been reached.

Inputs and Outputs

- Technology Type: Downdraft woody biomass gasification to electricity
- Facility Capacity: Up to 17,000 bone dry tons (BDT) of woody biomass per year
- Feedstock(s): The fuel supply for the proposed project would be solely woody biomass, derived from a variety of sources in the Lake Tahoe region, including forest-sourced material, such as hazardous fuels residuals (i.e., woody biomass material that pose a substantial fire threat to human or environmental health), forest thinning and harvest residuals (i.e., woody biomass generated from forest maintenance and restoration activities), and clean Wildland Urban Interface (WUI)-sourced waste materials from residential and commercial property defensible space clearing and property management activities, which would include brush and yard clippings, tree trimmings, and pine needles.
- Electricity amount: 2 MW of electricity exported to the regional grid
- How electricity is produced: Woody biomass is gasified, with syngas used to power two 1 MW GE Jenbacher Internal Combustion Engine gensets.
- Interconnect: Interconnect is to be direct to Liberty Energy, the local/regional Investor Owned Utility.
- Plans for pipeline injection to supply power plants: None planned
- Other Products: Principal byproduct is biochar. Biochar is defined as a solid material obtained from thermochemical conversion of biomass in an oxygen-limited environment. Biochar can be used for a

range of applications as an agent for soil improvement, improved resource use efficiency, remediation and/or protection against particular environmental pollution and as an avenue for greenhouse gas (GHG) mitigation. Biochar can be a very significant source of revenue for a woody biomass gasification facility. Approximately 10 to 15% of the total feedstock weight may be converted into biochar.

- Residuals Management: The syngas cleanup system produces some wastewater, which although is recycled, ultimately leads to some volume of wastewater needing to be removed from the project site to an appropriate treatment or disposal site.
- GHG emissions reduction calculated: GHG emissions from the proposed facility were calculated during the Environmental Impact Report process. Given the controversy surrounding whether or not the utilization of forest-sourced biomass is carbon "neutral", the EIR calculated GHG emissions as not carbon neutral, but did take into account the project offsetting GHG emissions from diverting the project feedstock from open pile burning (the most common practice of removing waste woody biomass in the forest. Although this results in a net increase in GHG emissions, it is still very low (3,809 MT/CO_2e). If the woody biomass were considered carbon neutral, the GHG emissions reduction would be 26,526 MT/CO_2e per year.

Financing and Customer(s)

- Initial Project Cost: Currently estimated at $13MM for 2 MW. $8MM for 1 MW.
- Project Financing: A combination of public funding and grant dollars from County, state, and federal sources. Will likely finance the project through the California Infrastructure and Economic Development Bank.
- Utility: Liberty Energy
- Other Customers (byproducts/residuals): A variety of customers for the biochar by-product.
- Expansion Plans and current phase: Depending on initial financing, the project may begin at 1 MW, followed by the addition of another MW within a two to three-year timeframe.

Project Contact Interview Questions Responses

The interview was conducted on June 21, 2017, with Mr. Brett Storey, formerly the Biomass Program Manager for the County of Placer, and now Principal Management Analyst for the Placer County Environmental Utilities. Mr. Storey has been associated with the Cabin Creek project since its inception. Below are his responses to the principal interview questions.

- **Project success –** Although the proposed facility currently lacks a PPA from the local IOU, there are many aspects of this project that would allow it to be successful (if and when it comes online). It would assist greatly in the reduction of open piling burning of forest thinnings in the Lake Tahoe Basin; the project is able to access significantly lower cost fuel due to arrangements between the County of Placer and the U.S. Forest Service; and it would promote further forest thinning to reduce catastrophic wildfire, particularly in the Lake Tahoe Basin.
- **Successful Project Characteristics –** Mr. Storey stated that his experience, based on this project, indicate that the most important project characteristic is getting a PPA earlier in the development process.
- **Permitting** – The project required a Conditional Use Permit from the Placer County Planning Department, which also implemented the CEQA process. Being a highly visible County-sponsored a full Environmental Impact Report was prepared. Although expensive and time-consuming, this comprehensive document allowed the County to override the opposition to the project and made the air permitting much easier. Air permits for the gasifier and flare, the two internal combustion engine gensets, the emergency flare, and the screening and drying of wood chips (before entry into the gasifiers) were issued by the Placer County APCD
- **Tariff Framework** – Facility is still in bilateral negotiations with the local IOU (Liberty Energy).

12.1.10 Case Study 10: North Fork Community Power, North Fork, CA

Project Information

- Project Name: North Fork Community Power
- Location: 59700 Road 225, North Fork, CA
- Owner: North Fork Community Power, LLC
- Developer: Phoenix Energy
- Contact: Greg Stangl, President, Phoenix Energy, (415) 286-7822, stangl@phoenixenergy.net
- Why was the technology and location chosen: Location was chosen, as it was a former sawmill site with large areas of buildable real estate. It is also centrally located to take advantage of various forest thinning operations planned for the next decade. It is also on land that is currently zoned industrial and the landowner is a partner in the LLC. The surrounding community is a very strong supporter of this project and its location.
- The technology (GE Water and Power gasifier and GE Jenbacher Internal Combustion Engine gensets) was chosen as this equipment offered an investment grade warranty program.
- Timeline: Project was initiated with a feasibility and technology evaluation study and resource assessment analysis in 2011, with technology and developer selected in 2012. In 2013 and 2014 land use permitting and CEQA process was conducted and CUP issued in early 2014. In early 2015, project received $5MM grant for the CEC' Electric Program Investment Charge program. Since 2015, permitting, construction, and interconnect studies, are being conducted, with operations now scheduled to begin in mid-2018
- Current Status: Under construction

Inputs and Outputs

- Technology Type: Downdraft woody biomass gasification to electricity
- Facility Capacity: Up to 18,000 bone dry tons (BDT) of woody biomass per year
- Feedstock(s): The fuel supply for the proposed project would be solely woody biomass, derived from a variety of sources in the North Fork and Madera County region of the Southern Sierra Nevada mountain and foothill range. This woody biomass includes forest-sourced material, such as hazardous fuels residuals (i.e., woody biomass material that pose a substantial fire threat to human or environmental health), forest thinning and harvest residuals (i.e., woody biomass generated from forest maintenance and restoration activities), and clean Wildland Urban Interface (WUI)-sourced waste materials from residential and commercial property defensible space clearing and property management activities, which would include brush and yard clippings, tree trimmings, and pine needles.
- The facility may also use no more than 20% of non-forest woody biomass from urban and agricultural wood waste sources.
- Electricity amount: 2 MW of electricity exported to the PG&E grid
- How is electricity produced: Woody biomass is gasified, with syngas used to power two 1 MW GE Jenbacher Internal Combustion Engine gensets.

- Interconnect: Interconnect is PG&E via a PPA per the BioMAT program. The North Fork project is currently in the BioMAT Category 3 queue (forest-sourced biomass).
- Plans for pipeline injection to supply power plants: None planned
- Other Products: Principal byproduct is biochar. Biochar is defined as a solid material obtained from thermochemical conversion of biomass in an oxygen-limited environment. Biochar can be used for a range of applications as an agent for soil improvement, improved resource use efficiency, remediation and/or protection against particular environmental pollution and as an avenue for greenhouse gas (GHG) mitigation. Biochar can be a very significant source of revenue for a woody biomass gasification facility. Approximately 10 to 15% of the total feedstock weight may be converted into biochar.
- Residuals Management: The syngas cleanup system produces some wastewater, which although is recycled, ultimately leads to some volume of wastewater needing to be removed from the project site to an appropriate treatment or disposal site.
- GHG emissions reduction calculated: GHG emissions from the proposed facility were calculated during the proposed project environmental impact analysis process, however only for 1 MW. Given the controversy surrounding whether or not the utilization of forest-sourced biomass is carbon "neutral", the EIR calculated GHG emissions as not carbon neutral, but did take into account the project offsetting GHG emissions from diverting the project feedstock from open pile burning (the most common practice of removing waste woody biomass in the forest. Although this results in a net increase in GHG emissions, it is still very low (1,847 MT/CO_2e). If the woody biomass were considered carbon neutral, the GHG emissions reduction would be 14,590 MT/CO_2e per year.

Financing and Customer(s)

- Initial Project Cost: $14.5 MM for 2 MW facility
- Project Financing: $5MM from CEC EPIC grant, $1MM from New Market Tax Credits, with remaining funds from private equity.
- Utility: PG&E via BioMAT PPA
- Other Customers (byproducts/residuals): A variety of customers for the biochar by-product.
- Expansion Plans and current phase: No plans at this time.

Project Contact Interview Questions Responses

The interview was conducted on July 10, 2017, with Mr. Greg Stangl, President of Phoenix Energy (San Francisco, CA). Mr. Stangl became associated with the proposed project in 2012 when his company was selected as the developer. Below are his responses to the principal interview questions.

- **Project success –** Although the project was conceived in 2012, a project-financing difficulty delayed construction until late 2016 and has not yet completed construction. Nonetheless, Mr. Stangl considered certain aspects of the project as an indication of tentative success. A major international company (General Electric) has both their small-scale biomass gasifier and internal combustion engine gensets (Jenbacher models) involved in the project and have issued performance warranties to North Fork Community Power. Also, the community support for the project is extremely high, along with support from the regulatory agencies.

  A challenge to the project has been the cost of interconnect. However, originally proposed in the PG&E System Impact Study at nearly $1.26MM, it has recently been lowered to less than $900K through meetings between the Governor's Tree Mortality Task Force Bioenergy Working Group, the project developer, and the utility.

- **Successful Project Characteristics –** Mr. Stangl opinion on this was relatively simple – the project must achieve an electricity generating time of 7,500 hours per year (85% capacity).
- **Permitting** – A Conditional Use Permit was required by the Madera County Planning Department for the project. This invoked the CEQA process, which ultimately led to a Mitigated Negative Declaration. Air quality permits are required for the gasifiers, internal combustion engine gensets, feedstock drying systems, and cooling tower system. These permits have been applied for but not yet granted. The San Joaquin Valley APCD nonetheless is allowing some construction activities to occur without the air permits (Authority to Construct) in place.
- **Tariff Framework** – Facility is currently in PG&E BioMAT Category 3 (forest-sourced biomass) PPA queue. Although the Category 3 price per kilowatt-hour continues to rise, Mr. Stangl has not yet asked for a PPA.

13. APPENDIX F: OTHER DISTRIBUTED ENERGY RESOURCES (DERS)-WIND AND STORAGE

The U.S. is also witnessing the development of community-scale renewable projects such as wind and storage.

Wind: According to the Distributed Wind Energy Association (DWEA), the nation's cumulative distributed wind power capacity is about 1 percent of all U.S. wind power capacity, or enough to power roughly 265,000 typical U.S. homes annually. Given below are some summary findings about the U.S. wind market from a 2016 market assessment (PNNL, 2017).

- The nation has added a total 992 megawatts of distributed wind in all 50 states, Puerto Rico, Guam and the U.S. Virgin Islands between 2003 and 2016.

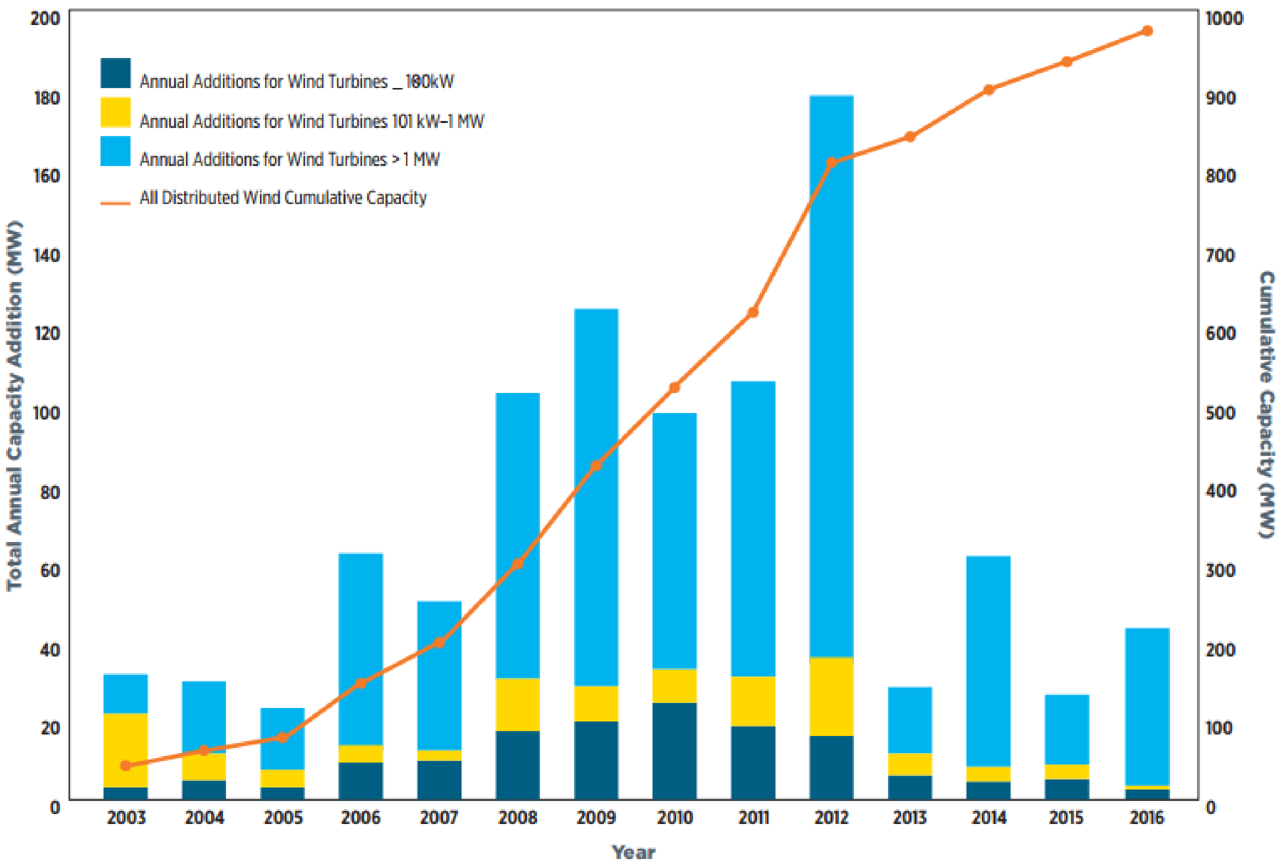

Figure 27: U.S. Distributed Wind Market

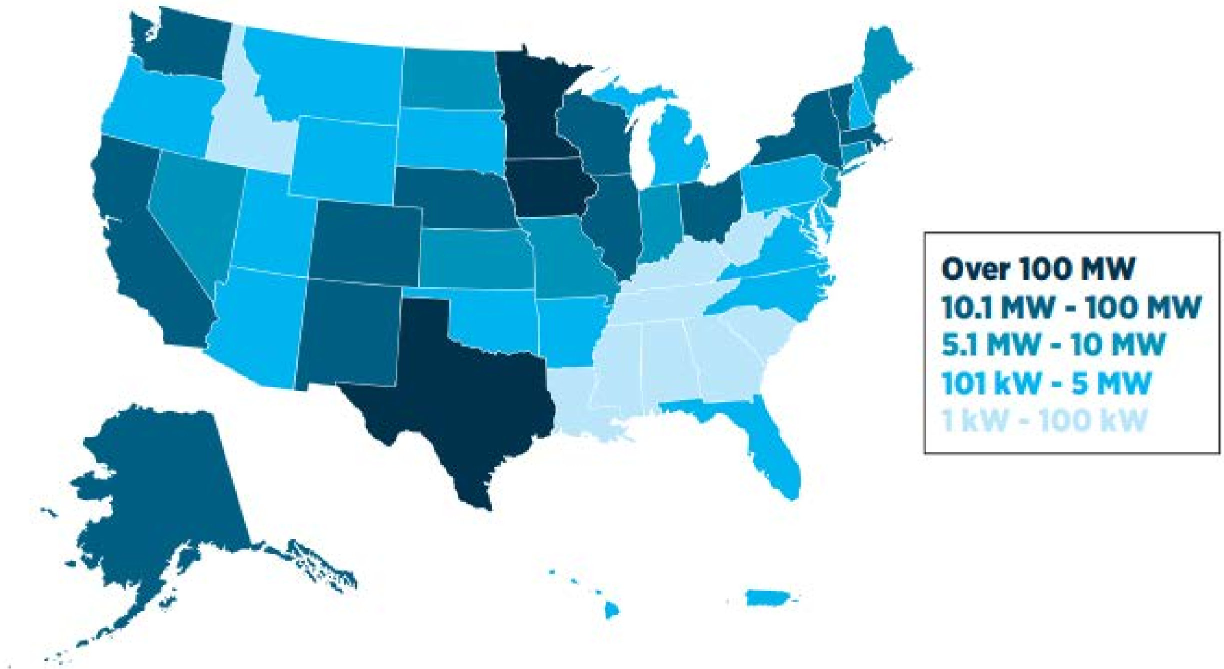

Figure 28: U.S. Distributed Wind Capacity by State

- The DWEA estimates that 27 states are home to companies that manufacture components for distributed wind turbines.
- Six U.S. manufacturers exported 10.3 megawatts in distributed wind turbines with an estimated value of $62 million.
- Institutional customers, such as utilities, churches, and schools, accounted for 29 megawatts of the new distributed wind power installed in 2016.
- New York led the nation by installing a quarter, or 627 kilowatts, of new small wind power capacity in 2016.
- The combined value of federal, state, and utility incentives given for distributed wind projects in 2016 was $12.8 million (excluding repaid loans, the federal investment tax credit, and federal depreciation). This reflects a relatively modest increase from the $10.6 million of 2015 funding awards, while still being significantly lower than in the preceding years when funding levels fluctuated between $100 million (2012), $15.4 million (2013), and $20.4 million (2014).

Federal, state, and utility incentives and policies continue to play an important role in the development of distributed wind. Renewable portfolio standards, net metering, interconnection standards and guidelines, Feed-in-Tariffs, municipal or community choice aggregation, utility programs, and the availability of grants, rebates, performance incentives, and state tax credits can impact the cost-effectiveness and uptake of distributed wind in a state. The combined value of federal, state, and utility incentives given for distributed wind projects in 2016 was $12.8 million (excluding repaid loans, the federal investment tax credit, and federal depreciation). This reflects a relatively modest increase from the $10.6 million of 2015 funding awards, while still being significantly lower than in the preceding years, when funding levels fluctuated between $100 million (2012), $15.4 million (2013), and $20.4 million (2014). As an example, Rhode Island led the United States in new distributed wind capacity additions with 15 MW installed in 2016. The states Rhode Island's Renewable Energy Growth Program, created in 2014 (Act H 8828) is designed to promote the installation of grid-connected renewable energy. The state also updated its net energy metering (NEM) rules in June 2016, to allow for virtual net energy metering (VNEM) and allowing VNEM systems to be owned by participating customers and financed by a third party and implemented through a power purchase agreement (PPA) or a lease. Local zoning rules and permitting requirement have been identified as a short-term barrier for the growth of wind projects in the U.S. (DWEA, 2015). The DWEA notes that wind turbines need towers that are 80 – 180 feet in height, but building departments often have ubiquitous 35-foot height restrictions and no special exemptions for individually owned wind turbines. These height restrictions have origins in the fire safety of inhabited structures over a century ago, and often throw the permitting process for wind turbines into the same zoning processes used for high rise buildings, liquor stores, adult entertainment venues, and oil refineries. It can take more man-hours to obtain a permit to install than it does to manufacture, deliver and install a small wind turbine. With over 25,000 separate zoning jurisdictions in the U.S., DWEA estimates that addressing each zoning ordinance individually would take more than one million person hours and cost more than $250 million.

Community Wind Market:

Stakeholders interviewed observed the following for community wind:

Respondents identified community-scale wind projects in California (Curry County), Colorado (Aspen), Kansas (Greensburg), Oregon (Portland), and Vermont (Brattleboro).

"Wind is a more challenging asset to develop than solar as it is less modular" – Policy expert

Community Energy Storage (CES): Community energy storage entails deployment of modular, distributed energy storage systems at or near points in the utility distribution system that are close to residential and business end users. The genesis of the CES concept was investigated by American Electric Power (AEP), starting in about 2005, to evaluate the prospects for and merits of locating advanced sodium sulfur (NaS) battery storage, rated at about two megawatts (MW), at substations. Two TRC Team respondents are aware of CES pilots, but have noted that it is hard to develop customer interest in CES projects, as it is not clear what storage offers to the individual

Community Storage:

Stakeholders interviewed observed the following for community storage:

Community storage could potentially provide some firm capacity for the inverter to provide distribution grid services, or CAISO market services, under a virtual net metering tariff. But it would be complicated because, under those conditions, the storage would be structured to be a wholesale asset and a retail asset at the same time.

Industry not anticipating any municipal policies or requirements for storage. They see it more likely that utilities will require storage requirements for interconnection of solar assets. Australia currently has such requirements.

customer. Storage offers demand-charge management benefits, although all members of a community are unlikely to have similar demand charge management needs. One respondent offered the following comment on a possible application of storage to voltage management: “If we needed to manage low voltages, community storage could potentially provide some firm capacity for the inverter to provide distribution grid services, or CAISO market services, under a virtual net metering tariff. But it would be complicated because, under those conditions, the storage would be structured to be a wholesale asset and a retail asset at the same time.” The CPUC has made efforts towards capitalizing the benefits of energy storage and has approved a target requiring the state’s three largest investor-owned utilities, aggregators, and other energy service providers to procure 1.3 gigawatts of energy storage by 2020 – some of this capacity could be delivered through community-scale solutions.

14. Appendix G: Community Solar Planning Best Practices

The community solar market in the U.S. is still evolving and the market is still exploring business models, financial structures, policy needs and other planning details for effective projects and programs. Recent guidance from SEPA attempts to break down the planning process into discrete steps to provide some guidance for future programs (SEPA, 2016). There are also insights available about what community solar customers are seeking in terms of future offering and design solutions (Shelton Group & SEPA, 2016). Given below is a summary of recommended planning processes and customer choices.

14.1 Step 1: Market Research and Establishment of Goals

The first step includes understanding the market conditions and establishing goals that are feasible under those conditions. Commonly cited goals for community solar programs include: providing increased renewable energy options for all customers; responding to needs of a select set of customers highly interested in solar; creating alternate and equitable options to rooftop solar; and educating consumers about solar power basics. It is important to understand the regulatory and policy regime of the market, consider ways other programs have been designed and implemented, and collect customer's voices. Data collection could include focus groups, customer surveys, or open meetings, to better incorporate customer needs in program design. Evaluation of potential incentives that could apply to a project is a key element in each of the planning processes.

14.2 Step 2: Program Design

SEPA identified twelve design decisions to consider before crafting a community solar program. These decisions are interactive and include factors regarding program economics, targeted subscribers, and program flexibility (See Figure 29).

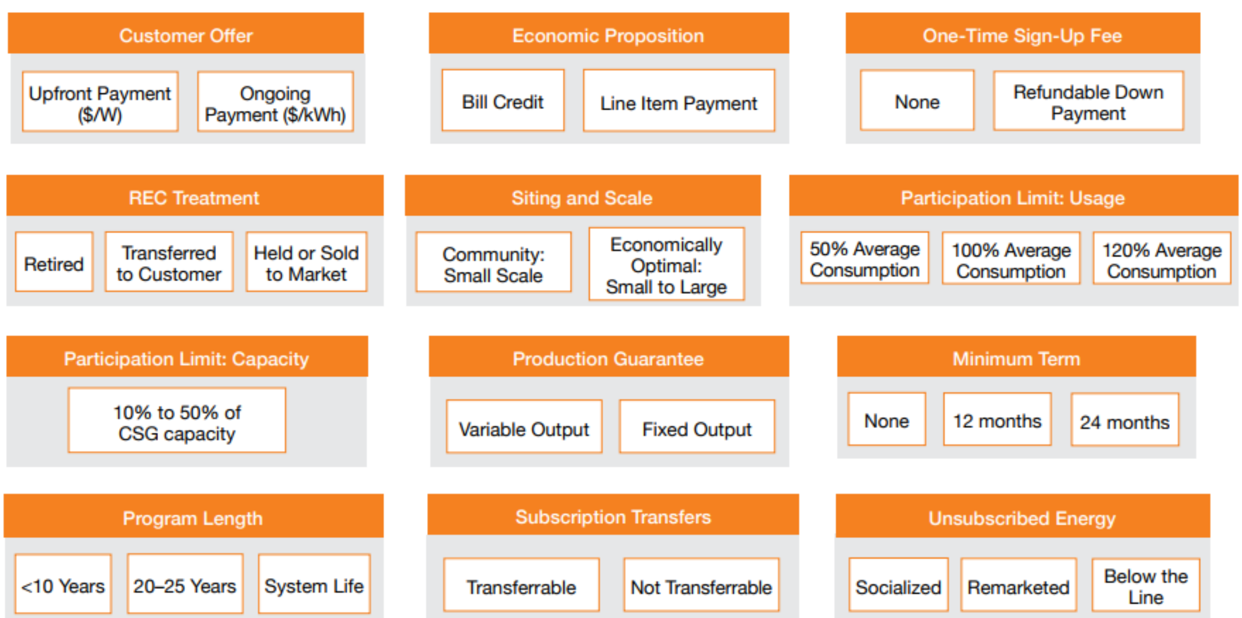

Figure 29: Community Solar Program Design Decision Factors

14.3 Step 3: Program Marketing

The TRC Team's literature review and stakeholder interview findings indicate that very few customers and industry stakeholders understand community solar adequately. Customer education, outreach, and marketing are critical to presenting a community solar programs to its audience and program administrators must decide on the appropriate marketing campaign. Survey results in Figure 30 show that although 59 percent of consumers are interested in solar in the U.S., only 20 percent of consumers are familiar with community solar, and only 14 percent of consumers are seriously considering that option (Shelton Group & SEPA, 2016). Providing stakeholders with consistency and transparency in the process of program design and implementation can contribute effectively towards success and increasing consumer confidence.

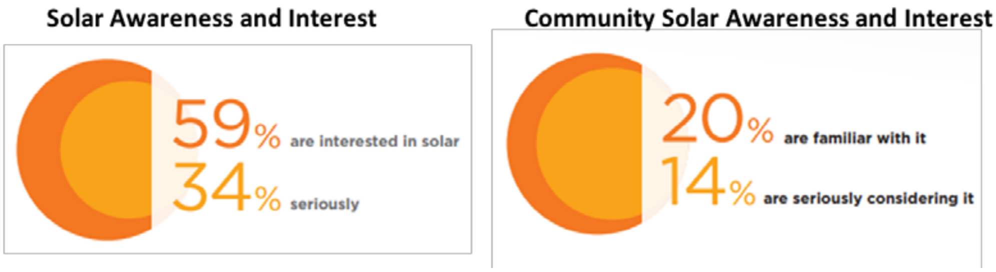

Figure 30: Consumer Preferences on Solar and Community Solar (Shelton Group & SEPA, 2016)

14.4 Step 4: Monitoring

This step is focused on establishing mechanisms to evaluate program effectiveness and providing a feedback loop to understand consumer satisfaction. SEPA recommends that a minimum of two low-cost tactics be pursued: (i) establishing an email address dedicated to the program to allow customers to provide feedback; and (ii) providing a waiting list to allow potential customers to sign up after a program has been fully subscribed.

14.5 Recommended Planning Best Practices

The TRC Team's research and interview data collection identified the following best practice recommendations for designing and implementing effective community solar programs:

- *Provide Multiple Options*: Most solar developers have more than one type of solar asset, and thus, offering a varied selection of subscription options (community, rooftop, lease, buy, etc.) is recommended as a key factor to establishing good customer relationships and expanding the customer base.
- *Use Effective Messaging*: Use messaging that resonates with the identified targets. The TRC Team's interview respondents reported that some programs had success appealing to a large market through targeted messaging. An effective message for low-to-moderate-income customers is: "You can buy a small share; we can finance that." For higher-income customers, effective messaging might be: You can buy multiple shares to meet 80% of your energy needs." The audience for solar are also typically pro-environment, so the messaging needs to be explicit about the impact on climate change and the chance to make a difference. Messaging should also emphasize reduced energy cost, which was the top cited driver for consumers interested in solar.
- *Involve the Utility:* Projects that are utility-sponsored, owned or have a partnership with the consumer's local utility are perceived to be more reliable and are more popular. SEPA market survey results show

that consumers prefer the utility to be involved in projects as a partner or as a sponsor, and government sponsorship was unpopular- with only a three percent consumer preference for that option.

- *Offer attractive financing:* Lack of financing or lack of confidence in the timely return on investment are the biggest barriers in the lack of interest in adoption solar. Offering zero-down, low-interest financing has been identified as a way to convert the uninterested consumer and increase adoption rates.

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