FINANCING PUBLIC SOLAR PROJECTS:
CALIFORNIA PUBLIC JURISDICTIONS' EXPERIENCES IN ACQUIRING
AND FINANCING SOLAR PHOTOVOLTAIC INSTALLATIONS

A Thesis

presented to

the Faculty of California Polytechnic State University,

San Luis Obispo

In Partial Fulfillment

of the Requirements for the Degree

Master of City and Regional Planning

By

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June 2013

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ABSTRACT

Financing Public Solar Projects: California Public Jurisdictions' Experiences in Acquiring and Financing Solar Photovoltaic Installations

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More efficient technologies, state laws as well as environmental, social, and political pressures have all contributed to placing solar acquisition on the agenda for California's public entities over the last half decade. But a key question for these frequently cash-strapped jurisdictions is how to utilize public dollars and lands, and how to leverage incentives to obtain solar PVs. As an alternative to outright purchase, a promising financing option made available to jurisdictions in recent years is ownership by a third party, usually the solar company, including various forms of Power Purchase Agreements (PPA's) and leasing. Due in part to state and federal incentives available between 2007 and 2012, these third-party provider (TPP) options have been used with increasing frequency; TPP arrangements accounted for "virtually all" larger and mid-size non-residential installations in 2008 (Sherwood 2008). A number of California's early adopters of third-party financing have installations that have now been operational for several years. Consequently, there is a new opportunity to evaluate third-party financing effectiveness.

This thesis reviews solar acquisition practices in California over the last six years, comparing financing options through document analysis and feedback from jurisdiction staff. It finds that directly buying installations has provided a slight advantage in direct savings and overall satisfaction for jurisdictions on average, but success generally depends upon the jurisdiction having secured upfront capital, usually from successfully accessing very low-interest loans or large grants. TPP projects have provided a good alternative to direct purchase, resulting in significant savings and positive reviews from jurisdictions, allowing them to invest in larger installation sizes, and to meet local policy goals or mandates. Additionally, this thesis makes observations about the limitations for installation sizing, impacts of siting on savings, tips for selecting a solar installer, the benefits of cooperative procurement arrangements, and the relative importance of existing and expired monetary incentives available for solar from 2006 through 2020.

Keywords: Power purchase agreement, third-party provider, solar financing, California Solar Initiative, public sector installations, public solar power

ACKNOWLEDGMENTS

I would like to extend my gratitude to the many individuals who supported my research and writing. Among them are the many dozens of staff of the jurisdictions across the State who completed my survey. I am especially grateful to Julie Benabente, Jason Coughlin, Keith Houchen, Ben Lucha, Ben Peters, Amy Reardon, and Heather Swan who each took their valuable time to share their experiences and knowledge.

Thank you also to my committee members, Adrienne Greve, Chris Clark, and Dennis Elliot who provided their time and feedback throughout the process and to Michael Boswell for providing advice on my survey tool. And additional gratitude goes to my friends and family for being a sounding board for my ideas and sorrows in relation to developing this document.

My greatest thanks go to my mother who patiently provided sage statistical advice, detailed draft edits, and emotional support at every turn, and who answered the phone at any time of day or night. Mom, this thesis is dedicated to you.

TABLE OF CONTENTS

List of Tables	ix
List of Figures	x
Background: Localizing Energy	1
The Public Jurisdiction’s Role	5
Policy and Market Context	9
California Policies and Incentives	10
Renewables Portfolio Standard	10
California Solar Initiative	11
Incentive Structures	12
Global Warming Solutions Act (AB-32).....	17
California Environmental Quality Act (CEQA) Requirements and Stream-lining	17
Federal Incentives	19
Production Tax Credits (PTC) and Investment Tax Credits (ITC)	19
Modified Accelerated Cost Recovery System (MACRS)	19
Section 1603 Treasury Grant	20
Financing Options	22
Direct Purchase	22
State and Local Government Bonds	23
Third Party Provider Options	25
Power Purchase Agreement.....	25
Leasing.....	26
Potential Benefits of Third Party Provider (TPP) Ownership Model	27
Methods.....	31
Method 1: Database Evaluation	31
Method 2: Surveys	32
Survey Sample Comparison to Database Population	34
Method 3: Jurisdiction Staff Interviews	35
Findings.....	37
General Trends in Public Entity Solar Acquisition	37

Geography	38
Jurisdiction Types	40
Size	42
Cost.....	43
Experiences and Perspectives.....	45
Ownership Financing Structure.....	48
Comparing Ownership Model Outcomes	51
In Sum.....	51
Barriers and Challenges	52
Completion Time.....	54
Project Cost	56
Savings	59
Ownership Structure and Sizing.....	62
Hybrid Financing.....	66
City of Lancaster’s Hybrid Model.....	66
System Size and Feasibility.....	68
Size and Cost	68
The Siting Challenge.....	72
Site Characteristics to Consider.....	72
The Solar Provider: Selecting and Dealing with your Contractor	80
Requests for Proposals (RFPs)	81
Interacting with the Solar Provider.....	88
The Next Big Thing: Cooperative Solar Procurement and Project Development	90
State of the Market.....	94
California’s Public Solar Market (2006-2012).....	94
Funding Sources Utilized (2006-2012)	96
Market Environment and Funding Sources (Post-2012).....	98
California Solar Initiative (CSI)	99
Modernization Grants and Proposition 39.....	100
Production Tax Credit (PTC) and Investment Tax Credit (ITC).....	100
SS 1603 Treasury Grants	100

Modified Accelerated Cost Recovery System (MACRS)	101
EPA Climate Communities Showcase	102
Department of Energy (DOE) 1705 Loan Program.....	102
EECBG	102
Clean Renewable Energy Bonds (CREBs).....	103
Qualified Energy Conservation Bonds (QECBs)	104
California Energy Commission Energy Efficiency Financing	104
K-12 only Bonds.....	105
Solar Market and Funding Post-2012.....	106
Conclusions.....	109
Bibliography	111
Appendix 1: Survey Sample Representativeness Assessment.....	115
Appendix 2: Survey Tool.....	119
Appendix 3: Interview Standard Questions	142
Appendix 4: Interviewees List	145
Appendix 5: Geographical Distribution of Solar Installations by Financing Structure ...	146

LIST OF TABLES

Table 1: Summary Comparison of Financing Options	27
Table 2: Advantages and Challenges of TPPs and Direct Buy for a Public Entity	29
Table 3: Initiated Installations by Utility Territory	37
Table 4: Average Installation Total Cost by Year	44
Table 5: Average Cost per Watt Compared to Installation Size	45
Table 6: Overall Satisfaction with the Solar Project.....	48
Table 7: Overall Satisfaction with Project	52
Table 8: Factors Ranked Most Important Financing Decisions.....	53
Table 9: Project Completion Time.....	56
Table 10: Average Cost of Installation by Cost Per Watt.....	57
Table 11: Expected Project Savings	60
Table 12: Survey Respondents Siting Locations	74
Table 13: Top 10 Solar Companies by Number of Installations	80
Table 14: Lead Cooperatives and Lead Agencies.....	91
Table 15: Public Jurisdictions Solar Summary Statistics (2013).....	96
Table 16: Rebates Utilized.....	97
Table 17: Tax Incentives Utilized.....	97
Table 18: Grants Utilized.....	98
Table 19: Bonds and Loans Utilized.....	98
Table 20: California Solar Initiative Capacity Status and Targets	99

LIST OF FIGURES

Figure 1: Annual Solar Purchase Cash Flows.....	7
Figure 2: Typical PPA Structure.....	26
Figure 3: Total Cumulative Projected Net Savings	30
Figure 4: Installations Initiated Per Year (2007-2012)	38
Figure 5: Locations of Public Solar Installations.....	39
Figure 6: Number of Solar Installation by County	40
Figure 7: Solar Installations by Jurisdiction Type	41
Figure 8: Jurisdiction Type	42
Figure 9: Installation Size Distribution.....	43
Figure 10: Cost Distribution	44
Figure 11: Obstacles to Project Implementation.....	46
Figure 12: Factors Prompting Projects	47
Figure 13: Ownership Structure Distribution of Installations (2007-2012).....	49
Figure 14: Total Installations Initiated (2007-2012).....	49
Figure 15: Percentage by Financing Structure.....	50
Figure 16: Installation Completion Time.....	55
Figure 17: Percent of Installations by Cost Per Watt.....	58
Figure 18: Installations' Cost per Watt Variance	59
Figure 19: Comparative Rate Forecast, California Polytechnic State University, 2006	62
Figure 20: Installations' Size Distributions by Ownership Structure.....	63
Figure 21: Project Size Distribution by Ownership Structure	65
Figure 22: Cost Comparison by System Size	69
Figure 23: Average Installation Size by Year.....	70
Figure 24: Ground Mounted Installation Types.....	73
Figure 25: Installation Racking Design	75
Figure 26: Specialized Design Elements for Installation, Palmdale.....	77
Figure 27: Campus Wide Solar Installation Siting Availability Map for Cal Poly University.....	79
Figure 28: Jurisdictions' Use of RFP	82
Figure 29: Survey Respondents' Solar Procurement/Project Cooperatives	91
Figure 30: Public Solar Projects in Sum	95
Figure 31: Status of Major Funding sources from 2006 to 2020.....	98
Figure 32: Percentage of Loan Funds by Recipient Type.....	105
Figure 33: Installations Initiated by Quarter (2006-2012).....	107
Figure 34: Jurisdictions Considering Solar in the Near Future.....	107

BACKGROUND: LOCALIZING ENERGY

California's public entities have found themselves at the center of a changing energy paradigm. These jurisdictions are in a position to play a critical role in a new energy system for reliable, affordable, and environmentally sustainable electric energy.

It hasn't long been that way. Little more than a decade ago, few would have argued with the conception that energy production and pursuit of more sustainable energy sources are matters best left to federal, state, and regional policy-makers. After all, under the current, and long dominant, centralized generation paradigm in California and across the US, electricity is mainly produced far away from the point of consumption, at large generation facilities, and then transmitted through high voltage wires to distribution grids and finally to end consumers. Technological, economic and political variables have long driven centralization whereby local jurisdictions have little or no engagement in energy decisions. But as one U.S. energy expert, Peter Fox-Penner, points out, the centralized energy power paradigm is fundamentally unsuited to the needs of energy in today's world, one bound by resource constraints and emissions constraints, since it "was designed to make and sell as much power as possible as cheaply as possible" (2010, p. 6).¹

A huge percentage of energy, 58%, is wasted due to inefficiencies, such as waste heat from power plants, transmission lines, and light bulbs (U.S. Department of Energy 2009).

A century of centralizing power production has led to a system with these inefficiencies

¹ Power lost over power lines from source production to end user is frequently as high as 30%, and increases with the distance over which the electricity travels. For detailed discussion of the centralized system and its increasing inefficiency and impacts see Fox-Penner and Randolph & Masters, documenting the cost of continuing reliance on centralized energy. For a full vision of how a fully distributed generation system might operate and its benefits, see writings by Amory Lovins.

lose more than \$19 billion for the US economy each year (Gellings, 2009).² The need for reliable power for ever larger and more power-hungry populations and other factors including health concerns relating to air pollution and not-in-my-backyard political advocacy³, have pushed large-scale utilities to build a large number of additional centralized plants further from population centers.

Additionally, many plants were built and kept running that were not needed except during very short periods of peak demand, generally during the day in summer months. Running these ‘peaker’ plants is extremely expensive as well as often the most polluting form of power.⁴ The result of these trends has been escalating prices and increasing inefficiency. As one US Department of Energy report put it in late 1990’s, “the situation appeared to be out of control, with most utilities requesting routine, often significant, rate increases and several utilities on the verge of bankruptcy” (Warwick, 2002).

Another, less quantifiable but no less important inefficiency created by today’s centralized system, is a highly complex and unwieldy institutional infrastructure.

Because power production is large-scale, with many moving pieces from producers, to wholesalers, to distributors across multiple state lines, it is regulated by many national and state level agencies, and is in constant political tug of war between the many players.

This complex arena of regulation and interests hinders innovation, and ultimately separates consumers from control over their own electricity supply.

² This estimate is based on 2005 US energy prices.

³ For additional information on public opposition to power plant siting, see Ducsik 1981.

⁴ The practice of having higher power capacity than is generally needed is typically referred to as “peak power” production or use of “peaker plants.” In standard power models, peaker plants can be turned on quickly to cover additional demand only at the brief times in a day and year is highest, but are much expensive, costing many times per kWh what base plants do. In depth discussion of peaker power and other technical inefficiencies of centralized power can be found in Smith, Craig B. “Efficient Electricity Use: A Reference Book on Energy Management for Engineers, Architects, Planners, and Managers” and Smith, Craig B. *Efficient Electricity Use: A Reference Book on Energy Management for Engineers, Architects, Planners, and Managers*. 2nd ed. New York; Pergamon Press, Inc.

A new energy paradigm---a paradigm now central to the State of California's energy policies⁵ and many other states is one that emphasizes distributed generation, or DG. DG refers to electricity that is produced close to where it will be used. The DG system depends emerging clean energy technologies, especially solar PV, coupled with emerging smart grid technologies.⁶ The promise of this new paradigm is drastically reduced inefficiencies in production, transmission and end use. Renewable energy DG systems can provide more power more efficiently to more people. They have the potential to drastically cut pollution. And, they can provide great dynamism, security, and simplicity the entire electricity system (Lovins, 2002, Randolph & Masters, 2009).

Amory Lovins, widely considered among the world's leading authorities on energy sustainability, has laid out what this new energy system, what he originally coined a "soft energy path," might look like and how it would operate. The soft path is defined by end-use solutions such as distributed renewables, smaller-scale production, and energy efficiency technologies (1976, 2002). According to Lovins (2011), such a shift could affordably transform the United States to almost total reliance on renewable energy in the near future.

Because of the inherent inefficiencies of centralized power and the resulting push toward distributed energy production, local jurisdiction involvement in energy is increasingly necessary to be environmentally and economically responsible. But in order to achieve a

⁵ See the California Energy Commission's 2013 Integrated Energy Policy Report Docket 13-IEP-1

⁶ 'Smart grid' refers to a number of technologies that allow for a power system that is controlled less by mechanical and human adjustment at the central station, and more by computer sensors that can analyze and adjust supply in "real time" and at truly micro-level. To learn more about the mechanics and economics of the Smart Grid, I recommend: Gellings, Clark. (2009) *The Smart Grid: Enabling Energy Efficiency and Demand Response*. Fairmont Press Inc; Lilburn, GA.

new energy paradigm based on distributed generation, local jurisdictions face uncharted territory: creating an entirely new relationship to power production.

Local jurisdictions, however, have traditionally had little direct impact on electricity planning, limiting their scope of influence to permit approvals of power lines, street lights, municipal building use, and occasionally their own building efficiency requirements. The new energy paradigm will mean cities will have to reverse more than seven decades of regulation favoring large, centralized, supply-side solutions that separate power production from end-users and instead to remove barriers to, and perhaps even promote localized production and city oversight (Munson, 2005)

New renewable and smart grid technologies are providing great opportunities to move toward distributed generation. In their book *Energy and Sustainability*, an urban planner John Randolph and a civil engineer Gilbert Masters, suggest that the only sustainable future scenario of energy is one in which these new technologies (rather than business as usual or world crises) drive the market” (2008). Solar PV’s are perhaps the central technology for localizing energy production and moving toward distributed generation. Photovoltaics offer the most direct and decentralized energy currently available, since they can generally be placed directly on or very near the site of energy use. In California, generous state and federal incentives in combination with technological and installation breakthroughs, have allowed PV’s to be cost competitive with standard grid options in the state (Long, 2011). Investment in PVs has skyrocketed in the last five years and has opened up opportunities for local jurisdictions to help build a more localized energy paradigm and even save on electricity prices in the long run (Sherwood, 2012).

THE PUBLIC JURISDICTION'S ROLE

Local jurisdictions of all shapes and sizes in California have entered the solar market in the last decade. For the purposes of this paper, local jurisdictions includes all public entities: municipal and county government as well as state-level agencies, public universities, school districts, and other special districts such as water providers. While they have differing electricity needs, assets, and legal structures, it is presumed that all these local jurisdictions are driven by similar factors and may share similar benefits and difficulties as public entities.

Right now, local jurisdictions have strong reasons to plan locally for changes in the energy paradigm and clean energy, namely solar, development. Factors that may potentially be driving local jurisdictions to acquire solar PVs can be summed up into four broad categories discussed below.

Meeting State requirements: Parts of local governments' continuing interest in renewable energy acquisition is as a method to comply with recent California policies and state laws. These will be summarized in greater depth below. Many jurisdictions are driven indirectly by the State Renewables Portfolio Standard SB X1-2; the California Solar Initiative in coordination with the Renewables Portfolio Standard, are driving the solar market and making it an investment with significant potential financial benefit for cash-strapped jurisdictions.

Also important from the local jurisdictional perspective is State greenhouse gas (GHG) emissions goals and legislation. AB-32, passed in 2007, established targets of reducing California's GHG emissions to 1990 levels by 2020 and 80% below 1990 levels by 2050. The Scoping Plan (authority from Executive Orders S-3-05 and B-16-2012) developed as

the compliance guide for AB-32, articulates local agencies are “essential partners” in achieving greenhouse gas reduction goals (Institute for Local Government 2010). This has been interpreted to mean that local governments are responsible for reducing both their own emissions and ensuring their community’s emissions are reduced. Consequently, acquiring solar PV electricity is an effective measure for a jurisdiction to achieve state-mandated emissions reductions goals.

Leading by example: Public entities can use their “bully pulpit” to show the public the benefit or at least feasibility of installing these solar systems. By installing and publicly showcasing PV, the jurisdiction demonstrates compliance with the law, emissions benefits, and co-benefits of going solar. The underlying motivation for being the champion of solar appears to come from both within the institution—that is from policy-makers and regulators who feel it’s the right the thing to do—and from without—that is from members of the public, often environmentalists or advocates of energy independence, who demand their government take a leadership role.

Financial and Security Optimization: For many local jurisdictions, the bottom-line motivations are direct benefits to government budget and operations. Electricity for facilities and lighting accounted for approximately \$9 billion in costs for California’s local governments in 2012 (Chantrill, 2012). Photovoltaics today offer the opportunity to save money on electricity, and to break free of dependence on the larger California energy market. It’s a market that has had large price volatility and energy shortages and brownouts throughout the last decade.

While a systematic analysis of jurisdictional savings does not appear available, much anecdotal evidence, gathered from statements made by staff and a large number of single

cases studies, indicate that long-term savings was a primary driver for public jurisdictions investing in solar (SEED Fund, 2012; Spiegel, 2012).

With current incentives and solar pricing, jurisdictions can achieve significant return on investments. The bar chart shown in **Figure 1** was developed by the SEED Fund to be representative of typical California public solar installation cash flows if the installation is purchased in full at the outset. The first red bar represents the initial expenditure, while the following blue bars represent the yearly savings from the electricity production, including estimated operations and maintenance costs. It reveals the significant potential savings timeline for jurisdictions.

Figure 1: Annual Solar Purchase Cash Flows

This chart displays each year's expected savings after buying the system (shown by the first year red bar. This is example cash flow using a classic direct buy model, based on experiences of multiple local governments' experiences. Source: SEED Fund, August 2012.

The Easy way to go Local: Local jurisdictions have a growing understanding that distributed renewable energy, produced locally and under their control. For jurisdictions looking to build local and renewable capacity, the most simple and straight-forward option is to build their own rather than (or before) influencing private community interests to do so.

POLICY AND MARKET CONTEXT

While this thesis is narrowly focused on public jurisdictions' acquisition of solar photovoltaic systems over the last six years, it is essential to place these recent actions and analysis within the broader context. That context is rapid renewable energy deployment in California and the nation over the last two decades and the transformation of energy systems as a result of policy and technological changes. In 2010, when federal tax subsidies for the market peaked, the United States added 878 MW of new grid-connected photovoltaics (PV) capacity and an estimated 40 MW of off-grid capacity (SEIA/GTM, 2011), representing a 92% increase over new capacity additions in 2009 according to the Energy Efficiency and Renewable Energy Office of the US Department of Energy. California was the largest player in market for PV, accounting for about 29% of the U.S. capacity (Sherwood, 2012).

Purchase of renewable energy has been fast-growing in California across all sectors—residential, commercial, non-profit, and public. Between 2002 and 2010, in-state generation grew by 270,126 gigawatt-hours and totaled 14% of the in-state electricity generation portfolio (“Renewable Energy Credits”, 2012). The state’s installed capacity of renewable energy witnessed an 18% growth between 2009 and 2010 alone (Sherwood, 2011).

A main driving force pushing California ahead of the rest of the country is a suite of enabling and supportive policies and a bevy of incentives for homeowners, businesses, as well as public entities. The following sections address the policy, regulatory, and financial framework that has been built up supporting the development of distributed energy generation in California.

California Policies and Incentives

The State of California has both the highest renewable generation requirements and some of the most extensive incentives and policies supporting solar development in the country. Development of renewable energy resources to fulfill the state's electricity demand is required by the 2003 California Energy Action Plan ("California Renewable Energy Overview and Programs", 2011).

Renewables Portfolio Standard

The State's Renewables Portfolio Standard (RPS) was first established 2002 under Senate Bill 1078, with the intent of increasing overall renewable energy production in the state by mandating investor-owned utilities acquired a certain percentage of their electricity production from renewable sources. The program was accelerated in 2006 under Senate Bill 107 and expanded in 2011 under Senate Bill 2. The California's Renewables Portfolio Standard (RPS) is one of the most ambitious renewable energy standards in the country. As of 2011, the RPS program requires investor-owned utilities, electric service providers, and community choice aggregators to achieve procure 33% of their electricity portfolio from eligible renewable energy resources by 2020. RPS procurement rules include specific multi-year compliance periods that act as mandated benchmarks for meeting the overall 33% mandate by 2020.

The RPS is the primary driver of solar acquisition in California and most other states. In California, most other incentives are structured to support meeting RPS mandates.

California Solar Initiative

While the RPS provides overall state mandates for utility energy sourcing from multiple renewables, the California Solar initiative (CSI), provides subsidies toward the purchase of solar PVs. Any entity can qualify for CSI rebates including homeowners, commercial businesses, nonprofits, and all types and levels of public entities. CSI is operated by the State's investor-owned utilities; thus, CSI is not available to entities that are their own utility, notably municipal utilities, are not covered by the program. Sacramento Municipal Utility District, Los Angeles Department of Power and Water, and San Francisco Public Utilities Commission, and other municipal utilities as well as cooperative energy providers and CCA's have their own incentives available.

CSI was developed as a result of the Million Solar Roofs Program initiated by Governor Schwarzenegger in 2004. In 2006, the CPUC collaborated with the California Energy Commission (CEC) to develop the framework of the CSI Program which was authorized in August 2006, by Governor Schwarzenegger with passage of Senate Bill 1. The program was launched at the beginning of the following year.

The California Solar Initiative has a budget of \$2 billion over 10 years to distribute in incentives to help reach a goal of 1,940 MW of installed solar capacity by 2016. The incentive is provided per watt installed. When the program began in 2007 incentive for systems less than 50 kW were \$2.50/Watt AC for residential and commercial systems, and \$3.25/Watt AC for government entities and nonprofits. These incentives are adjusted based on expected performance of the specific PV system at a particular site.

For a system greater than 50 kW, performance based incentives are paid for the first six years at \$0.39/kWh for taxable entities and \$0.50/kWh for government entities and

nonprofits. These incentives ramp down as state-level PV capacity is reached in each California utility's service territory. As of 2012, public jurisdiction PV projects (<50 kW) receive an up-front incentive of \$2.65/Watt. The program will continue until funds run out.

Incentive Structures

Several policy mechanisms are fundamental to effectiveness of the Renewables Portfolio Standard and the California Solar Initiative by providing revenue streams and procurement accounting. Most prominent of these policy mechanisms are the *systems benefit charge*, *net metering* and *renewable energy credits (RECs)*.

Systems Benefits Charge. Effective 2007, starting with Senate Bill 1 (SB-1), the State developed programs to support the RPS goals and specifically to aid onsite solar projects. Incentives for CSU are funded through a systems benefit charge (SBC), which is collected as a small percentage fee on ratepayer bills. The program then uses the collected funds to provide cash back for all applicants who install solar energy systems of less than one megawatt (Chong, 2011).

Net Metering. Under net metering, when a PV system is installed it is connected to the larger electricity grid, but is "behind-the-meter." This means that electricity produced is credited against the retail electricity provided by the local utility. When the PV system produces energy, it is counted on the meter against the charge, while when the system is not producing the owner still receives electricity from the grid and the meter counts a positive charge. Thanks to AB-920, at the end of the payment period, if the PV system put more electricity onto the grid than was used by the owner, the owner of the system is guaranteed compensation for the excess electricity put back into the grid by the local

utility provider. The utility provides either a direct payment to the customer or a credit towards future use. The advantage is that electricity produced behind-the-meter ultimately reduces the demand from the customer's local utility, and thus the utility electricity bill (Cory, Coughlin & Coggeshall, 2008).

California Renewable Energy Credits (CRECs) and SB 107. The CRECs are a similar but separate incentive mechanism than that provided by the California Solar Initiative. The basic concept underlying RECs is straightforward. When a renewable generator produces power they provide two simultaneous outputs: electricity and environmental benefit. RECs are certificates that represent the environmental benefit of renewable production. For every unit of electricity produced by a renewable generator, a corresponding unit of REC is also produced. These RECs can potentially be separated from the associated electricity and sold, either to a voluntary market comprised of purchasers who seek to buy green bragging rights, or to an RPS compliance market comprised primarily of utilities under a legal compulsion to procure a growing percentage of electricity from renewable sources. A renewable generator can benefit from tradable RECs by realizing a source of revenue from the sale of the environmental attributes resulting from their renewable generation—effectively monetizing what had previously been an external benefit (Elder, 2007).

Unlike incentives under CSI, RECs are directly connected to RPS mandates: Renewable Energy Credits are the mechanism for utilities' compliance with the Renewables portfolio Standard. RECs are tradable commodities, separate from the electricity produced, that bundle the “attributes” of renewable electricity generation separate from the energy itself.

California law (Public Utilities Code §399.12[f]) defines a REC as:

"a certificate of proof, issued through the accounting system established by the Energy Commission... that one unit of electricity was generated and delivered by an eligible renewable energy resource."

Utilities receive RECs when they fund PV projects. One REC typically represents the attributes of 1 megawatt-hour (MWh) of renewable electricity generation. There are three types of transactions involving RECs – “bundled”, “unbundled”, and “tradable”.

Bundled Power Purchase Agreements are for both the RECs and energy associated with an eligible RPS facility. Unbundled REC transactions are for only the REC’s. Once the RECs are unbundled from the energy, the energy is considered null (non-renewable) power and no green claims can be made for use of this null electricity. Tradable REC transactions are also for only the owner and utilities, but then the RECs can be traded to multiple participants before ultimately used for RPS compliance (California Public Utilities Commission, February 2012).

In net metering situations, California state law dictates that the owner (e.g. party with the solar installation) retains the RECs. However, if the utility contributes financial incentives or rebates to a project, most utilities require the RECs be transferred to them in exchange (Holt, 2006). The third-party model tends to cause confusion because the customer and property owner is not the owner of the solar power installation. In the case of the PPA model, though not the lease model, the developer, i.e. the installation owner, is the rightful owner of the RECs, and sells the electricity to the customer but retains the RECs for sale into the RPS market. This allows the third-provider to offer a jurisdiction that is price competitive with traditional generation. But if the jurisdiction is interested in claiming that they are “solar powered” they must either assure retaining them is in the initial contract or must purchase the RECs from the solar developer.

California Public Utilities Code 218. One difficulty that inhibited the use of third-party financing is how states typically define a ‘utility’ in PUC regulations and/or state legislation. In most states, any institution that sells retail electricity to customers is defined as a ‘utility.’ All utilities are then subject to PUC regulation and processes. Because third-party owners of PV systems sell power to the hosts/end-users via the power purchase agreement, the third-party provider would be considered a utility. Being considered a utility presents a challenge for developers wanting to use the third-party PPA model, as PUC regulation adds administrative costs and development time to projects, making this finance model less economically appealing, and for many smaller companies, entirely infeasible.

California solved this problem through legislation that changed the definition of a utility. California Public Utilities Code 218 is very specific in the kinds of ownership and technologies that are allowed. In fact, the code specifically exempts these kind of solar third-party providers from the definition of an Electrical Corporation:

“...a corporation or person employing cogeneration technology or producing power from other than a conventional power source for the generation of electricity solely for.... the use of or sale to not more than two other corporations or persons solely for use on the real property on which the electricity is generated.”

Third-party providers do not have to be classified as utilities, and avoid PUC regulation, as long the electricity they provide is used on the property where it is produced. The state does require third-party owners to set up new independent business units (such as an LLC) for each commercial system they install in order to comply with the rules and utilize the third-party ownership PPA, but this a far smaller administrative and legal burden than direct PUC oversight. The law made it possible for the first time for

developers to enter a PPA contract and make it financially feasible. Thus, a new structure developed that uses a PPA to cater to the distributed generation (DG) markets. In the wake of the new law, some of the first companies to use the model for solar power financing were Sun Edison and MMA Renewable Ventures (Kollins, 2008). By 2012, dozens of mid-size and larger solar companies have used the third-party model to successfully contract and install PVs with hundreds of commercial, industrial, and government hosts.

Proposition 39. In late 2012, California approved by ballot initiative a new incentive to support PV installation. The initiative, Proposition 39, allocates \$2.5 billion to energy conservation programs, funded through tax on multi-state businesses as a percentage of their sales made in California. This the largest State energy efficiency initiative in the US to date. Half of that money is slated to fund energy efficiency and clean energy projects in California schools and other public buildings over six years, to be dispersed through the State Office of Public School Construction. School Districts and colleges will likely be able to access the money through the existing Modernization Grants under the School Facility Program (SFP), which funds a range of energy efficiency facility improvements and education resource proposals. The SFP provides grants approved by the State Allocation Board (SAB), and requires a 40% local contribution. Prop 39 will be among only a few new source of funds to infuse new capital into an otherwise depressed market for major infrastructure and building investments among cash-strapped public jurisdictions.

Global Warming Solutions Act (AB-32)

Another important piece of California law driving solar acquisition across the state, and especially among public jurisdictions is the California Global Warming Solutions Act, established by the passage of Assembly Bill 32 (AB-32) in 2006. AB-32 requires that state achieve a 15% reduction in greenhouse gas emissions by 2020. Subsequent actions by the State Legislature and Attorney General have established that all public institutions, including local-level jurisdiction, must take action to help achieve state-wide greenhouse gas reduction targets. Since solar energy production is virtually emissions-free, there is new motivation to install PV's to reduce electricity related emissions that would otherwise result from fossil fuel produced electricity. The kick-off of the carbon trading market, in which public entities are free to participate, also adds incentive to produce renewable energy to get a hold of credits.

Along with this framework of enabling and mandatory legislation, there are significant federal incentives available. As will be explained below, third-party financing models make savings even from tax rebates useful to public entities. Below, some of the most prominent incentives are described—though it is not necessarily a comprehensive list.

California Environmental Quality Act (CEQA) Requirements and Stream-lining

For many local governments' ensuring compliance with new GHG emissions reporting requirements under the California Environmental Quality Act (CEQA) is another potential motivator. SB 97, enacted in 2007, amends the CEQA statute to establish that GHG emissions and the effects of GHG emissions are appropriate subjects for CEQA analysis. It directed the California Office of Planning and Research (OPR) to develop draft State CEQA Guidelines “for the mitigation of GHG emissions or the effects of GHG emissions” and directed the Resources Agency to certify and adopt the State CEQA

Guidelines. Under the new guidelines, jurisdictions that establish Climate Action Plans and policies to reduce GHG emissions—like installing solar capacity—can benefit from streamlining of CEQA analysis and mitigation measures for development projects in their community.

Federal Incentives

Several Federal incentives programs have also been essential in driving the solar PV market, according to a report by Interstate Renewable Energy Council (2012).

Production Tax Credits (PTC) and Investment Tax Credits (ITC)

As a result of the Energy Improvement and Extension Act of 2008 (H.R. 1424), enacted in October 2008, commercial businesses can receive either investment tax credit (ITC) or a production tax credit (PTC), a per-kilowatt-hour tax credit for electricity generated by qualified energy resources.

PTC and ITC incentives have been renewed and expanded numerous times, most recently by H.R. 1424 (Div. B, Sec. 101 & 102) in October 2008 and again by H.R. 1 (Div. B, Section 1101 & 1102) in February 2009 (DSIRE 2011) and are expected to continue being funded for the near foreseeable future.

Modified Accelerated Cost Recovery System (MACRS)

Under these House Resolutions (PTC and ITC), investors in new renewable power generation projects are able to accelerate the depreciation of the renewable project assets. This allows them to defer related federal taxable income and obligations in the early years of the projects. Renewable power investors are able to use the five-year Modified Accelerated Cost Recovery System (MACRS) accelerated depreciation method for most of their project capital costs. Together, the tax credits and the accelerated depreciation compose what is referred to as the “tax benefits” of a renewable project. A Chadbourne & Parke tax attorney estimates the tax benefits for solar and wind projects—on a present value basis—amount to about 56% of the initial capital costs (Mendelsohn & Harper, 2012).

One of the largest monetary incentives that have been provided on the federal level is Section 1603, also known as the U.S. Treasury Grant Program, activated as part the *Recovery and Reinvestment Act* (“the Recovery Act”) which was signed into law on February 17, 2009. Section 1603 of the Recovery Act enables qualifying commercial renewable energy projects to choose between the Section 45 PTC, the Section 48 ITC, or a cash grant of equal value to the Section 48 ITC (Bolinger et al., 2010). This option to receive a cash grant, in most cases covering 30% of project costs upfront, from the US was intended by Congress to “...temporarily fill the gap created by the diminished investor demand for tax credits,” and thereby achieve “...the near term goal of creating and retaining jobs...as well as the long-term benefit of expanding the use of clean and renewable energy and decreasing our dependency on non-renewable energy sources” (U.S. Department of the Treasury, 2009).

Section 1603 Treasury Grant

The Section 1603 Treasury Grant has motivated a large percentage of renewable energy projects. A study conducted by the Lawrence Berkeley National Laboratory found that roughly 16.9 MW of the estimated 465 MW of PV installed had been awarded grants as of March 1, 2010 (all projects had to be permitted by the end of 2011 to eligible for the grant option). The grant has in total funded 16.9 gigawatts (GW) of new installed capacity made up of a wide range of technologies, including hydroelectric, geothermal, biomass, and fuel cells.

The 1603 Treasury Grant expired on December 31, 2011, although projects that started construction prior to that date are eligible to receive the award. The program funding will end completely by 2016. While the loss of the 1603 has clear financial impacts on solar,

it is likely that the end of the Treasury Grant will be more harmful to other renewable energy sectors such as wind than solar PVs (Jason Coughlin, NREL, personal correspondence, October 10, 2012). Nonetheless, the expiration may impact project feasibility, especially for smaller installations, where investors have less expectation of large return on investment. Smaller projects are expected to have more difficulty attracting needed financial capital (Mendehlson & Harper 2012)

FINANCING OPTIONS

The premise of the third-party financing model is that instead of owning the PV system, a public entity hosts a system that is paid for and owned by a taxable entity (e.g. a solar company or bank). The public entity enters into a long-term contract with the third party to purchase the electricity generated on its property. The electricity price is typically set at or below the host's current retail rate for the first year, and then will typically increase at a fixed percentage over time.

This section will provide an overview of purchasing options available to local jurisdictions, with emphasis on the Third-Party Provider (TPP) model and potential benefits connected to them. Although there are distinctions by sub-category and procedure, financing options that involve TPP generally include Power Purchase Agreements (PPA) and Solar Leasing. These options can be compared to direct purchase of solar installations, either through direct capital using jurisdiction funds or grant fund or low-interest bonding. Both the National Renewable Energy Laboratory and the SEED fund have produced reports that provide comprehensive information on the attributes and financial benefits and drawbacks of these financing options, which this thesis uses as a baseline for exploring California jurisdictions' experiences in their own solar procurement.

Direct Purchase

The simplest and most direct method is for a jurisdiction to buy the installation upfront with general fund, dedicated funds, loans or grant money. Direct Purchase generally requires six or seven figure upfront costs, in order to get installations of adequate size.

This is feasible for wealthy or very large jurisdictions, and literature review suggests that

this option results in the highest return on investment (SEED Fund, 2012). With direct purchase the jurisdiction immediately owns the system and all the power it produces and the renewable energy credits it supplies. It also means they are responsible for operation and maintaining the installation. Since public jurisdictions are non-taxable organizations, they cannot capture federal tax benefits in the purchase.

State and Local Government Bonds

Public jurisdictions can issue bonds to secure capital for PV projects. Municipal bonds, a way to finance direct purchase (and in some cases TPP projects, as well), can be issued by state and local governments to finance capital expenditures, including PV installations. General obligation bonds can be utilized, where-in the principal and interest are secured by the full faith and credit of the jurisdiction, and are usually supported by the jurisdiction's taxing power. These bonds are voter approved, the rules of which differ by state and can range from a simple majority to complex formulas for taxpayer approval. The municipality is generally limited in the amount of debt that can be incurred, usually as a percentage of a jurisdiction's assessed valuation. An alternative structure is revenue bonds, whereby principal and interest are secured from revenues derived from fees and/or charges paid by the users of the facility. Revenue bonds are often used for investments like toll roads, where they collect fees from motorists for their usage. As stated, bonds generally require voter approval. Otherwise, bonding has similar financial benefits and disadvantages of direct purchase.

There are several bonding options that are designed specifically for solar acquisition by public entities. Tax legislation enacted in 2008, 2009 and 2010 created four types of tax credit bonds under the Internal Revenue Code including Qualified Zone Academy Bonds

(QZABS), Qualified School Construction Bonds (QSCBs), Qualified Energy Conservation Bonds (QCEBs) and New Clean Renewable Energy Bonds (CREBS).

The first two bonds are specifically aimed at public school systems. The Zone Academy Bond must include the creation of “programs to enhance the curriculum, increase graduation rates, improve employment opportunities, and better prepare students for the workplace or higher education” and must be completed in the partnership with a private entity (California Department of Education, 2013). Holders of QZABs and QSCBs receive a tax credit equal to 100% of the credit rate on the bonds. A couple solar companies, notably Chevron Energy Solutions and Sunpower, have created successful models using QZABs and QSCB’s, designing large-scale projects for dozens of school districts, and even designing the educational curriculum to meet the educational programs requirement.

The Energy Improvement and Extension Act of 2008 (Div. A, Sec. 107) allocated \$800 million for Clean Renewable Energy Bonds (CREBs). In February 2009, the American Recovery and Reinvestment Act of 2009 (Div. B, Sec. 1111) allocated an additional \$1.6 billion for New CREBs, for a total New CREB allocation of \$2.4 billion. Holders of CREBs and QCEBs receive a tax credit equal to 70% of the credit rate on the bonds. However, due to lack of publicity or other financing issues, QCEBs and CREBs have been utilized by only a small handful of public jurisdictions. The US Treasury states that some \$5.6 billion of allocations to over 1,800 applicants have been made for these tax credits. However, only a small part of the approved tax credits have actually led to a bond being issued.

An investigation by Bloomberg New Energy Finance in 2012 found that total issuance up to around \$1 billion--bonds have been issued for less than 20% of allocated tax credits (Linder, Stefan & De Capua, 2012). California has utilized a higher percentage of its allocation of the bonding money than most, but CREBs remains a rarely used funding mechanism (Coughlin, NREL, personal correspondence, October 10, 2012).

Third Party Provider Options

Power Purchase Agreement

The third-party ownership PPA structure is a long-term contract between a customer and a third-party solar PV developer. The developer builds and owns a PV system on the customer's property and sells all of the power to the customer. This allows the customer to support solar power while avoiding upfront costs as well as operations and maintenance. Prices are fixed over a long-term established period, usually 20 years or more. Typically, the Power Purchasing Agreement establishes an initial rate and some marginal increase from year to year known as an escalator. Rates are negotiated between the purchasing entity and the solar owner, utilizing forecasts of where the grid market rates will change over that period. Rates are usually fixed in the contract, but can also float with some link to market rates. Establishing rates ahead of time and can ensure completely dependable energy costs. On the flip side, if grid energy prices drop below the PPA agreed price, the organization loses rather than saves money.

Another aspect of the PPA that is an important benefit for some public entities is that the solar provider/owner manages all aspects of system financing, installation, and maintenance, and bears all operating risks. The overall structure of a PPA is illustrated in **Figure 2** below.

Most PPA contracts now also have a measure that allows for the public jurisdiction to buy the installation from the third-party provider after a certain number of years, typically at the point of expiration of federal tax subsidies. Thus, the PPA offers a path to eventual ownership of the installation.

Figure 2: Typical PPA Structure

This flow-chart illustrates the relationships between the jurisdiction and other parties in a typical PPA arrangement.

Source: SEED Fund, 2012.

PPA's increase affordability for jurisdictions without enough of their own capitol, and in recent years have also allowed them to take advantage of the considerable federal tax benefits, which are typically passed on by the solar contractor.

Leasing

Like with PPAs, in a solar lease, the PV system is built on the local jurisdiction's property but is owned by a third-party, in this case usually a bank investor, which then sells all of the power produced to the jurisdiction. The jurisdiction pays fixed monthly payments over the agreed life of the contract. In this case, the jurisdiction is responsible for maintaining the installation just as they would be responsible for any leased facility. As with PPA's this mechanism allows the jurisdiction to receive the savings of federal

tax incentives, passed through the investor-owner of the system, and requires little or no upfront capital. Lease agreements also sometimes allow for the jurisdiction to buy out the installation, though usually not until the end of the lease period.

Table 1 summarizes the basic components of each financing option.

Table 1: Summary Comparison of Financing Options

Direct Buy	Power Purchase Agreement	Lease
Upfront payment.	Payment per kWh.	Recurring payment for use of equipment.
Own the system.	Equipment owned by 3rd party.	Equipment owned by 3rd party.
Retain RECs.	Rarely Retain RECs.	Sometimes Retain RECs.
Does not qualify for tax incentives.	Qualifies for tax incentives.	Qualifies for tax incentives.
Maintenance jurisdiction's responsibility.	Maintenance 3rd party's responsibility.	Maintenance jurisdiction's responsibility.

This table summarizes key components of each financing model.

Potential Benefits of Third Party Provider (TPP) Ownership Model

Power Purchase Agreements and Leasing agreements are ultimately similar options and together are referred to as Third Party Provider (TPP) finance structures. Third-party ownership is a financing mechanism that allows institutions that otherwise would find purchasing Solar PVs difficult or infeasible to enter the solar PV market. Third-party ownership model is a potential way to monetize federal tax benefits, avoid paying the upfront cost of solar, more efficiently allocate public funds, and to accelerate the deployment of solar PV.

An obvious benefit of choosing TPP structures is that they allow for local jurisdictions to acquire solar without having to provide all the necessary purchasing capital upfront. TPP allows local jurisdictions to attain solar PV's on their property, and pay only for the power used upfront while the third-party operator pays for the actual panels and

installation as well as operation costs. This means that even without upfront capital, a jurisdiction can afford solar and immediately start seeing a return on investment in their energy bills. For many jurisdictions without large coffers, immediate access to grant allocations, or the political will to issue taxpayer approved bonds or taxes, this can open the door to solar projects that would otherwise be financially out of reach.

An additional benefit of the third-party model, is that it allows jurisdictions to take advantage of the significant cost savings on sticker prices of solar through federal tax incentives. Since local jurisdictions are exempt from federal taxes, they had previously gained no benefit from the federal incentives. With advent of third-party ownership, a portion of the tax savings achieved by the private solar owner could be passed on to the jurisdiction.

According to the Solar Energy Industry Association, third-party models have helped to spur a significant increase in the growth of solar PV installations in the U.S. In 2007—which was even prior to significant increases in federal incentives under the American Investment and Recovery Act-- over 12,700 new grid-tied systems were installed in the U.S. with an annual capacity of nearly 150 MW-dc (SEIA/GTM, 2011). In addition, a 2007 Greentech Media study found that 50% of the growth in the commercial and institutional market for solar in the United States was carried out using the third-party owner model compared to just 10% in 2006.

Table 2, below, summarizes the advantages of each of the financing structures.

Table 2: Advantages and Challenges of TPPs and Direct Buy for a Public Entity

	Third-Party Provider	Direct Buy
Advantages	No/low upfront outlay of capital.	One-time cost.
	Ability for tax-exempt entity to benefit from savings passed on from federal tax incentives.	Ability to use cheap public debt (with low or even zero interest and tax-exempt debt issuance through bonding).
	Predetermined electricity price for 15–25 years.	Full control over the project: design, operations, and risks.
	No operating and maintenance responsibilities.	Ability to choose what to do with renewable energy attributes generated by the project (retain or monetize).
	Path to ownership (if included as an option in the contract).	Greater potential savings since you avoid third party expenses and interest rates.
	Not responsible for maintenance and repair.	
Challenges	The process of negotiating contract can be lengthy and costly.	Requires a lot of upfront capital--generally requiring a grant or good credit for bonds or loans.
	Public entity has limited control over project design, operations, and risks.	The public entity cannot monetize the value provided by federal renewable energy tax incentives.
	PPA pricing may be sub-optimal (developer could receive most of the financial benefits).	Need expertise to navigate potential revenues from renewable-portfolio-standard-driven subsidies.
	If PPA term is less than the system useful life, the host must purchase the system at fair market value at the end of the term.	Debt issues and limitations could prohibit the model.
	Locked in pricing can result in "loses" if grid rates end up being lower during the life of the project.	Maintenance and upkeep on equipment. Potentially equipment becomes outdated.
	Might encounter legal difficulties if solar provider goes bankrupt or out of business.	
	Rarely can retain the RECs to get "credit" for power production.	

This table summarizes potential advantages and challenges of financing model, garnered from literature review (see Cory, October 2009; Cory, Coughlin & Coggeshall, May 2008; Kollins 2008; SEED Fund, August 2012).

The projected savings line graph, shown in **Figure 3**, was developed by the SEED Fund, a Solar PPA collaborative non-profit, and shows the typical Return on Investment from the different financing mechanisms.

Figure 3: Total Cumulative Projected Net Savings

The SEED Fund used conglomerated data from a number jurisdictional experiences to provide this sample of savings over time that would be achieved by a typical Bay Area Municipality using each of the three ownership models to finance a solar project. Source: SEED Fund.

Since 2006, as the solar market has skyrocketed generally, projects utilizing TPP financing have grown even faster. Since the sunset of the most significant of the tax incentives use of TPP had dropped noticeably. However, it remains, and will likely continue to remain, an important and growing sector of the market. While TPP has the potential to provide a number of benefits to public entities in California, its ultimate benefit compared to directly purchased installations over the long-term is a question that remains to be answered.

METHODS

The study identified solar projects of public entities that own land, including cities, counties, universities, K-12 schools, and special district governments, in California between 2007 and 2012. The number of California jurisdictions' using TPP models for their solar projects has rapidly increased in the last half-dozen years. Since this rapid deployment no retrospective analysis with a wider scope than single case studies has been conducted. The following methods were designed to capture public entities' experiences financing solar projects and comparing ownership models. It uses both broad scope methods to understand the whole market, and fine-grain methods to capture details of individual jurisdictions' process that led to successful implementation on the project-level.

Method 1: Database Evaluation

This first method uses an existing database of solar installations maintained by the California Solar Initiative.⁷ The CSI database includes all jurisdictions solar installations that have been filed to request the cash-back incentives provided through the Initiative. The CSI incentives are available to all public entities within the territory of the California Public Utilities Commission (CPUC) regulated utilities (aka Investor-Owned Utilities IOU's), has a fairly straightforward application process, and its availability well-known throughout the state. Therefore, it was assumed that the database is virtually

⁷ The California Solar Initiative database provides information on all solar projects in investor-owned utility territory where an application was submitted for the CSI rebate. The data is updated weekly and is available to the general public. It can be assumed that the vast majority of solar projects in the investor-owned areas of the State that been initiated since 2007 are accounted for within the database.

comprehensive, and entirely representative of solar PV projects occurring in California during the period of interest.

A list of jurisdictions that acquired solar between January 2007 and January 2013 was created using filtered data downloaded from the California Solar Initiative Database on January 13th 2013. Data was filtered to include only projects where the “host customer”⁸ was “government”⁹, and resulted in a list of 1,745 PV installations initiated over the six-year period. The goal of the database evaluation was to provide a general understanding in trends of solar acquisition by public entities in California since 2007. This comprehensive list of installations from across the state allowed for analysis of frequencies of utilized solar installers and the location as well as trends in project timelines, size, and cost for all installations initiated by the beginning of 2013. These factors were used to compare and establish a general state-of-the-practice and differences between installations financed by direct buy (DB) structures and by Third-Party Provider (TPP)¹⁰ structures.

Method 2: Surveys

To better understand what drove decisions to acquire solar and the size, type, and siting of projects as well as the financing choices, an online survey was conducted with staff of jurisdiction’s that have completed, or were in the process, of obtaining solar PVs. The

⁸ Defined as the “entity that meets all of the following criteria: 1) has legal rights to occupy the Site, 2) receives retail level electric service from Pacific Gas and Electric Company, Southern California Edison Company, or San Diego Gas and Electric Company, 3) is the utility customer of record at the Site 4) is connected to the electric grid, and 5) is the recipient of the net electricity generated from the solar equipment.

⁹ This is based on tax status. Essentially all public entities are classified as government within the database.

¹⁰ In the CSI database, a TPP is defined as a “3rd party owner” and classified as such whenever the System Owner is a different entity than the Host Customer for a solar power system.

survey method provided greater detail about a number of factors that were available from CSI data, such funding sources, siting, savings realized, and contents of contracts with the solar provider. Additionally, the survey method was able to capture staffs' evaluation of their project and the process, such as the most difficult barriers they faced, overall satisfaction with the project, basic tips for success, and whether they intend to pursue more solar projects in the future.

It is important to note that respondents were asked to respond to the survey in regards to a *solar project*, as opposed to a solar *installation*. This differs from the database analysis, wherein each “unit” of analysis was a single installation¹¹. A solar installation is defined by siting of solar PV panels at a single site, usually under a single meter. While each installation may have its own contract, in most cases, jurisdictions' choose to build several installations on multiple sites under one financial agreement, under a single proposal with a solar provider, and with the approval of jurisdiction decision-makers as a whole. Since most jurisdictions think and make decisions regarding their solar acquisition on project-level, it was more appropriate to ask respondents to answer survey questions with project-level, rather than single installation, issues in mind.

Surveys were sent to contacts from a list of 140 jurisdictions. The list of jurisdictions was drawn from CSI database of installations sorted for all “government” host customers, and culled of all jurisdiction name duplicates, resulting in a list of approximately 400 unique jurisdictions. The CSI database did not provide any contact information for the jurisdiction or staff, so that information was collected by searching through publicly

¹¹ The CSI database is organized by installation and does not provide enough information to determine which installations were undertaken as part of larger solar projects.

available sources such as jurisdiction websites, news articles, and press releases or by calling the jurisdictions. Additional contact information was also collected through the snowballing method.¹² The survey resulted in 45 unique responses—a 32% response rate.

The survey tool was distributed using email invitations and administered using the online survey software tool Survey Monkey. The survey used skip logic dependent on responses to specific questions. Thus the number of questions presented to respondents varied between 29 and 42. Most surveys were completed in less than 15 minutes.¹³

Questions addressed project demographics (e.g. size, siting, etc.), process, such as financing and ownership options considered, project goals, potential buy-out timeline, and overall satisfaction with various aspects of the project, and its operational outcomes. The survey tool is available in the Appendix.

Survey Sample Comparison to Database Population

The respondents of the survey appear to be fairly representative of all public entities engaged in solar acquisition across California, according to type of public entity, service utility area, project sizes, and financing mechanisms used. Conclusions about the representativeness to the larger jurisdictional experience are based on CSI database installations characteristics and literature review of existing research on the public entity solar market.

The survey sample does deviate from the database of all installations in several ways. These deviations are briefly summarized below, with greater detail provided in Appendix

¹² A question in the survey tool itself asked respondents to identify staff at other jurisdictions that had also had a solar project.

¹³ Median completion time was 10.5 minutes.

XX. The survey has a greater proportion of third party provider projects. This was by design. Since TPP projects are a minority of all projects but are of interest in this thesis, jurisdictions which had completed multiple projects any one of which was done with a third party provider, were asked to complete the survey with respect to that project. Projects described in the survey also tend to be larger, on average, than the installations in the CSI data base. This partly results from the methodological choice to emphasize TPP projects in the survey, but also probably is the result of the emphasis on projects, which consist of several installations, and therefore, by definition, tend to be larger. Finally, PG&E projects are disproportionally represented in the survey sample.

Method 3: Jurisdiction Staff Interviews

Interviews were conducted to supplement database and survey data with more rich details about specific cases. Interviews allowed for greater understanding of the process and underlying social, political, financial, and technical factors that contributed to the decision-making for solar projects and the physical design of the PV installations themselves.

Interviews, generally between 45 to 90 minutes were conducted with staff from a subset of jurisdictions from Method 2. In total, follow-up interviews were conducted with staff of six jurisdictions, including a university, three cities, a county, and a school district. Jurisdictions were chosen selectively for interviews with the goal of representing the full range jurisdiction types, all three ownership financing models, expected savings, and challenges faced during the project implementation. Interviews were conducted over the phone or in-person. Staff interviewed filled a variety of positions at their jurisdictions

including an energy officer, a public works director, a facilities manager, and a local power authority project manager.

For jurisdictions selected for in-depth interviews, analysis of project documents, such as contract agreements, RFPs, and public outreach documents, was also conducted as appropriate to gain a comprehensive understanding project issues and dynamics.

Informational interviews were also conducted with several individuals that can be considered experts on the California solar market, to provide research scope and general perspective on the topic. Interviewees included a solar industry representative from one of the largest solar contracting companies operating in California, California Public Utilities Commission staff that work with the California Solar Initiative, and solar financial policy analysts from the National Renewable Energy Laboratory.

A full list of the names, titles, and affiliation of interviewees is available in the Appendix.

FINDINGS

In this chapter, findings from the three methods of analysis are presented in order to provide a general picture of the state-of-the-practice of solar procurement by public jurisdictions in California over the 6-year period, 2007 to 2012.

General Trends in Public Entity Solar Acquisition

Method 1 database analysis shows that between 2007 and the end of 2012 just over 1,700 government-hosted solar installations have been initiated. In total, the installations make up approximately 416 Megawatts (MW) of installed solar capacity. **Table 3** below shows the total number of projects and MW capacity broken down by utility territory.

Table 3: Initiated Installations by Utility Territory

	# of Installations	% of Total Installations	# of MW	% of Total MW
CCSE	201	12%	38.6	9%
PG&E	1,007	58%	219.7	53%
SCE	537	31%	158.0	38%
Total	1,745	100%	416.3	100%

This table provides summary data of public entity solar installations recorded CSI database including, total number of installations and total MW, broken out by utility territory, as well as in sum.

As shown in **Figure 4**, the number of projects initiated per year has trended upward over the six-year period. As of the end of 2012, 72%, (1,251 installations) were fully installed and operational, with the majority completed in 2010 or later. Notably, the number of projects initiated spiked in 2010 and dropped off in 2012. This is perhaps a reflection of availability federal funding in those years; major pots of money provided under the American Recovery and Reinvestment Act (eg. grant programs, such as EECBG) were allocated between 2009 and 2010 and largely depleted by 2012.

Figure 4: Installations Initiated Per Year (2007-2012)

This bar chart shows the number of installations initiated each year, as recorded by incentive applications requests submitted in the CSI database.

Geography

Figure 5 illustrates that public solar projects have been initiated throughout the state.

The majority of installations have been initiated in PG&E territory—covering most of the northern part of the state. This is not surprising considering that PG&E encompasses the largest territory and has the most customers. However, as **Figure 6** demonstrates, several Counties in southern California have the highest numbers of installations overall. Los Angeles, the largest county by population, also has the most installations.

Figure 5: Locations of Public Solar Installations

This map shows the zip code areas (in gold) where solar installations have been initiated since 2006, based on CSI data.

Figure 6: Number of Solar Installation by County

The chart shows the total number of installations initiated by public entities by county since 2006, based on CSI data.

Jurisdiction Types

A broad spectrum of public sector entities is procuring solar in California, as shown in **Figure 7**.¹⁴ Solar installations have been initiated to power facilities for municipalities, counties, special service providers such as fire and water districts, K-12 school districts, and public colleges and universities, as well as state and federally operated facilities. As shown, the largest percentage, more school districts have initiated solar installations than any other jurisdiction type statewide.

¹⁴ The publicly available CSI database provides the location of installations down the zip code level of granularity but does not specify ownership of installation. The jurisdictional information provided was generated using data requested from California Public Utilities Commission staff that maintains the CSI database.

Figure 7: Solar Installations by Jurisdiction Type

Here, the jurisdictions that are procuring solar that are recorded in the CSI database are broken down by type of entity.

Of the survey respondents, however, more jurisdictions were municipalities (42%) than any other type (**Figure 8**). School districts were the second largest group, with 24% of respondents reporting that jurisdiction type. Two of the respondents were state level agencies -- the California Department of Transportation, which has completed a project with 70 installations statewide, and the California General Services Department which has acted as the lead agency for installations on dozens of state-owned executive branch facilities. Federal-level jurisdictions included military facilities, national parks, and other federally owned facilities that are located in the state.

Figure 8: Jurisdiction Type

This bar chart shows survey respondents' jurisdictions' type.

Size

The installations vary widely in size, with the median size project at just under 140 kW (see **Figure 9**). However, the *average* installation size is much larger—280 kW. This is the result of a number of very large projects; 17% are over 400 kW. By comparison, the size the average commercial solar installation over the same period was just shy of 150 kW (“California Solar Initiative”, 2013).

Figure 9: Installation Size Distribution

This box-plot depicts total sizes of installations recorded in the CSI database divided into quartiles. The upper quartile (largest 25%) of installations has a much larger range than the others due to a number of extreme outliers.

Cost

As with trends in the rest of the industry discussed in the literature, the cost of production and installation of solar has gone down for public entity installations. As shown in **Table 4**, the average system price—measured in terms of cost per watt¹⁵-- consistently dropped between 2007 and 2012.

¹⁵ Cost per watt is calculated as a simple division of total cost of the installation by total number of watts installed.

Table 4: Average Installation Total Cost by Year

Year Initiated	Mean (\$/W)	Std. Deviation
2007	\$8.60	\$2.80
2008	\$8.40	\$2.20
2009	\$6.20	\$1.70
2010	\$5.40	\$1.50
2011	\$5.50	\$1.60
2012	\$4.60	\$1.30
All Years	\$5.60	\$2.00

This table compares the mean installation cost, in terms of cost per watt, to the year installation process was initiated. Data is drawn from the CSI database.

For projects initiated in 2012, the cost per installed watt was a just a little more than half that of projects initiated in 2007. **Figure 10** shows the distribution of cost per watt across installations.

Figure 10: Cost Distribution

This line graph shows the distribution of system costs within the CSI Program for all completed projects, displaying the cost range on the X-axis and the percentage of filtered applications on the Y-axis.

Source: CSI produced graphic.

Table 5 reveals that the standard deviation dropping from \$2.8 to \$1.7, suggesting that prices offered for installations are not only lower but also more consistent. Jurisdictions

are thus likely seeing more reliable pricing offered by installers in the last year (2012) than in the past.

Interestingly, larger projects do not seem to benefit that much from economies of scale. As shown by **Table 5**, very large projects—those over 322 kW in the top quintile—do not have a greater than a \$0.20 average price per watt advantage over other projects over 52 kW. The disadvantages of smaller projects (100 kW approximate threshold) are discussed in the *System Size and Feasibility* Section starting on page 60.

Table 5: Average Cost per Watt Compared to Installation Size

Installation Size (Quintiles)	Mean	# of Installations	Std. Deviation	Std. Error of Mean
0 – 52 kW	\$7.4	435	\$2.9	\$0.1
53-139 kW	\$5.6	437	\$2.0	\$0.1
139-322 kW	\$5.5	436	\$2.0	\$0.1
322-5,312 kW	\$5.4	436	\$1.7	\$0.1
Total	\$6.0	1744	\$2.3	\$0.1

The average cost (in price per watt) is broken down by installation size quintiles. Table illustrates that above the lowest quintile (lowest 20%), installation size does not seem to result in any lower prices.

Experiences and Perspectives

Respondents were asked a number of opinion-based questions about the process and outcome of their jurisdiction’s solar project. A number of these questions allowed open-ended response or invited commentary.

Respondents were asked to rate how big a range of potential obstacles/challenges were in getting the jurisdiction’s solar project underway. As shown in **Figure 11**, the issue most commonly cited as a very big obstacle was money. Staff time, siting and decision-maker approval were each also listed as ‘somewhat big’ or ‘very big’ obstacles by 20% or more of respondents.

Notably, less than a third reported public buy-in as a very big issue, and more than two-thirds, thought it was “not very big” or “not an issue at all.” Technological issues were also not considered a major issue by most jurisdictions, even though of the six respondents that reported having any problem with their solar project, five involved technological problems or failures.

Figure 11: Obstacles to Project Implementation

Surveyed jurisdictions were asked how important various obstacles or challenges were to completing the solar project.

Savings on electricity, as shown in **Figure 12**, was an overriding theme for prompting solar projects across jurisdictions. Also common factors considered very important for prompting solar projects were environmental considerations, incentives or rebates with limited time or money availability, and the jurisdictions own policies or goals. Interestingly from this author’s perspective, state mandates were rarely considered as even a somewhat important factor in prompting respondent jurisdiction solar projects.

Figure 12: Factors Prompting Projects

Surveyed jurisdictions were asked how important various factors were in prompting their jurisdiction to undertake the solar project.

It’s not surprising that anticipated savings played a strong role in prompting projects, as nearly a third respondents reported that they expected to achieve a 40% or greater money savings on electricity cost from solar over the life of the project. Another third (34%) expected to see over 10% savings. More about these jurisdictions’ project savings and forecasts and factors involved are discussed in the *State of the Market* Section starting on page 80.

Perhaps the most important survey result for other public entities considering their own solar project, is the high level satisfaction among those jurisdictions that have gone through the process. Nearly all respondents reported being satisfied overall with their solar project. As shown in **Table 6**, an overwhelming majority of jurisdictions, 68%, were “very satisfied,” and 96% were at least “somewhat satisfied.”

Table 6: Overall Satisfaction with the Solar Project

Level of Satisfaction	Total	%
Very satisfied	27	68%
Somewhat satisfied	11	28%
Somewhat dissatisfied	2	5%
Not Satisfied	0	0%
Total	40	100%

Survey respondents were asked to assess their overall satisfaction with their solar project. The majority indicated they were very satisfied with the process and outcome.

Ownership Financing Structure

As noted in the introduction, the use of third-party provider ownership structure is a very recent model within the public sector. As of yet, there are still far fewer TPP projects than direct buy projects across the state (see **Figure 13**). As of January 2013, only 569 TPP projects were initiated and 248 were completed and operational.

Figure 13: Ownership Structure Distribution of Installations (2007-2012)

The CSI database reveals that roughly a third of solar installations are being procured using the TPP ownership model over the last 6 years.

A range of factors—discussed further in next Section starting on page 45--have caused a rapid increase in its use in this sector and the non-residential sector generally. **Figure 14** shows the cumulative number TPP installations initiated by year compared to Direct Buy installations.

Figure 14: Total Installations Initiated (2007-2012)

This line graph demonstrates cumulative number of solar installations of each ownership model initiated over the 6 year period, as recorded in the CSI database.

The survey had an approximate 60-40% split in financing model used. The over-representation of TPP models was by design, to provide the best opportunity to garner an accurate picture of the experiences of the limited number of jurisdictions who utilized it. Of surveyed jurisdictions, 42% used a TPP ownership model (**Figure 15**). Of those, nearly all used had executed a Power Purchase Agreement with a solar provider with a contract lasting on average 20 years. The two jurisdictions that utilized the other TPP option of lease were both School Districts. Literature analysis indicates that leasing is much more common for K-12 districts than any other public entity, which is likely the result of the preference of solar installers that target schools (discussed more in *Solar Provider* Section starting on page 72) and a range of other factors.

Figure 15: Percentage by Financing Structure

Survey respondents were asked to select what ownership model was used for the solar project.

COMPARING OWNERSHIP MODEL OUTCOMES

A primary goal of this thesis is to develop a better understanding of the financing and ownership options available to public jurisdictions, to assess the circumstances when each structure is appropriate, and the factors associated with successful implementation of each structure. This section synthesizes information from all three methods of analysis and moves from a general assessment of the two approaches to a more specific discussion of project characteristics and implementation issues. It concludes with the case study from Lancaster City, which has developed a unique model to get the most benefit out of third party provider financing.

In Sum

In Method 2, respondents were asked about their overall satisfaction with the jurisdiction's solar project, considering all aspects of development and performance. As shown in **Table 7**, directly purchased projects come out slightly on top. Over 90% of respondents using both structures were at least somewhat satisfied with the project. However, staff from jurisdictions that directly purchased their project installations was much more likely than their TPP counterparts to be 'very satisfied' (82% versus 50%).

Information gathered from interviews suggests that these ratings are influenced by several factors. The first has to do with project complexity and staffing requirements. TPP projects tend to require more staff time in siting and negotiation; these arise because there are more factors to consider when developing a third party ownership contract. A second reason is ownership and control over the installation. The issue here actually appears to be an extension of the first, in that staff report a continuing need for communication and interactions with the solar provider regarding maintenance, and rate changes. While a jurisdiction that owns its own installation can potentially do

maintenance in-house or contract with any most convenient contractor available when maintenance is needed, for TPP most jurisdictions must continue to work the solar provider as maintenance or other requirements arise. Additional staff time and effort were required regardless of the performance of the solar provider. Indeed, most of the respondents were very satisfied with their solar provider.

Table 7: Overall Satisfaction with Project

	Direct Buy		Third Party Provider		Total
	# of Responses	%	# of Responses	%	
<i>Very satisfied</i>	18	82%	9	50%	27
<i>Somewhat satisfied</i>	3	14%	8	44%	11
<i>Somewhat dissatisfied</i>	1	5%	1	6%	2
<i>Total</i>	22	100%	18	100%	40

This table summarizes surveyed staffs' responses to the question: taking into consideration all aspects of the solar project, how satisfied are you?

Barriers and Challenges

The advantages of TPP structures are the ability to procure significant solar capacity, while still avoiding the need for large sums of capital, capturing federal tax incentives, and lower maintenance/operations responsibility. On the flip side, the literature cites challenges of opting for TPP structures as higher soft costs, primarily the legal costs associated with developing a fairly complex purchase agreement contract, and lack of ownership over renewable energy credits and the installations themselves.

Barriers and challenges suggested in the literature figure prominently in the survey results. For instance, survey respondents were asked what factors proved most important to their jurisdiction in financing decisions. As shown in the corresponding split **Table 8** below, the two most important financial considerations for jurisdictions using both structures were anticipated long-term savings and the per kWh price of electricity.

However, for those opting for TPP projects, the prospect of lower maintenance costs figured prominently in their decision calculus. In contrast, ownership of the installation was a highly ranked consideration for jurisdictions that chose direct purchase. Accessing incentives is ranked third in the DB category but doesn't make the top five for TPP.

Table 8: Factors Ranked Most Important Financing Decisions

Direct Buy			Third-Party Provider		
<i>Factor</i>	Rating Average	Rank	<i>Factor</i>	Rating Average	Rank
<i>Long-term savings</i>	1.15	1	<i>Long-term savings</i>	1.13	1
<i>Per kW price of electricity</i>	1.31	2	<i>Per kW price of electricity</i>	1.38	2
<i>Accessing state/federal incentives</i>	1.33	3	<i>Total cost (gross)</i>	1.47	3
<i>Upfront cost</i>	1.38	4	<i>Upfront cost</i>	1.47	4
<i>Ownership/control over installation</i>	1.46	5	<i>Lower maintenance/responsibility</i>	1.53	5

Surveyed staff was asked to rank how important certain factors were for financing their solar project. These tables demonstrate the differences in what factors were most influential for jurisdictions that chose direct purchase vs those who chose TPP. Rating averages were calculated by assigning numerical values to level of importance assigned: very important =1, somewhat important=2, not important=3. Thus, those factors with rating closest to 1 were ranked highest overall.

The biggest challenges recognized by staff using the two ownership structures thus appear to be differed. Legal costs were a much bigger challenge for TPP projects than for direct buy projects. For jurisdictions pursuing direct buy projects the bigger challenge was securing the capital needed to move forward. This was less of a challenge for TPP projects, where the third party provider was responsible for raising the capital based on the long term commitment of the jurisdiction to purchase the energy to be produced by the installation. For direct projects, attainment of grants and rebates were critical to project financing and thus figured prominently their project efforts; for TPP projects such

rebates were passed on by the solar contractor owning the installation so less directly figured into their thinking.

Completion Time

As might be expected due to the greater legal and contractual complexity leading to a longer planning phase, TPP projects tend to take longer to reach completion than Direct Buy installations¹⁶. Method 1 analysis shows that TPP installations took an average of 1.6 years to be completed after being initiated through the application process--about five months longer than direct buy counterparts. However, the longer times as a result of TPP structuring appears to be a spurious relationship. As the box-plot in **Figure 21** shows in the Ownership Structure and Sizing section of this thesis, TPP projects tend to be larger (discussed in more detail a little later in this thesis). A comparison of average completion times, when adjusting for size differences, showed no clear pattern or significant relationship (significance varied between .125 and .669 in compare means test controlling for size) between ownership structure and project duration. Project size was the driving explanatory factor.

Also illustrated by the box-plot in **Figure 16**, there is greater *variability* in completion times for TPP projects. The boxes in the Figure each represent the median and middle quartiles—the 25% of cases above and below the median. The middle quartiles for TPP projects show a much greater variability than those for direct buy projects. Large variations in completion time are not just the result of more extreme cases but are simply

¹⁶ Completion date is recorded in the CSI database for only about 1/3 of total installations. However, the results found are still significant (.01).

a factor with a lot of variation for TPP projects, comparatively to their direct buy counterparts.

Figure 16: Installation Completion Time

This boxplot shows median, range, and quartiles on installation completion times for direct buy installations and TPP installations in the CSI database.

The survey findings are consistent with the Method 1 database findings: TPP projects take somewhat longer to complete than direct buy projects, as shown in **Table 9** below. But the magnitude of the difference reported is much smaller and not statistically significant (Sig .82). Again, the average project size was larger for jurisdictions with TPP, likely accounting for some of the difference in time to completion. Jurisdictions' experiences as reported in the survey do suggest that it's quite possible to execute a TPP project from planning to construction completion along a similar timeline as a straight purchase project.

Regardless of ownership structure, and perhaps most worthy of note for jurisdictions considering solar in the future, one can expect most projects -- even smaller scale projects -- to take between one and three years to complete.

Table 9: Project Completion Time

Project Completion Time	Direct Buy		TPP	
	#	%	#	%
<i>Less than 6 months</i>	4	16%	2	12%
<i>6 months to 1 year</i>	8	32%	5	29%
<i>1—3 year</i>	13	52%	10	59%
<i>Total</i>	25	100%	17	100%

Surveyed staff were asked about how long their project took (or was expected to take) from initial planning phase to commencing operation.

Project Cost

Direct comparison of the overall cost of TPP installations to direct buy installations is difficult due to how costs are reported in the CSI database for TPP installations.¹⁷

However, in general TPP projects appear to have lower costs, in terms of price per watt installed, than their DB counterparts. **Table 10** shows the average cost per watt for all initiated installations, by ownership structure type. The average cost for TPP is \$5.37,

¹⁷ The current \$/watt data available for California Solar Initiative projects present difficulties when comparing host customer-owned and third-party-owned systems (e.g. leases or power purchase agreements (PPAs)). The reported costs for host customer-owned systems are simple, as they reflect the purchase price inclusive of parts, labor, permitting fees, overhead, and profit. Third-party-owned systems, on the other hand, are reported in a variety of ways, and may also capture costs for additional services. There are at least three different ways third-party owners are reporting their system costs:

- If the third-party owner buys the system from a contractor, the third-party owner may report that sale price as the system price to the CSI Program. This value, however, does not include the overhead and profit of the third-party owner, which are actually passed through to the host customer.
- Alternatively, the third-party owner may report the "Fair Market Value" (FMV) of the system, a figure reported in tax filings. FMV is an estimate of the market value of a property, based on what a knowledgeable, willing, and unpressured buyer would probably pay in an arm's-length transaction.
- Lastly, the third-party owner may report the appraised sum of cost inputs.

nearly a \$1 lower than the \$6.30 average cost per watt reported for Direct Buy projects.¹⁸

Figure 17, a line graph prepared by the CSI, shows the distribution of comparative cost of a sampling of each project type.

Table 10: Average Cost of Installation by Cost Per Watt

Funding Type	Average Cost per Watt	Number of Installations	Standard Deviation
<i>Direct Buy</i>	\$6.3	1177	\$2.4
<i>Third-Party Provider</i>	\$5.4	568	\$2.1
<i>Combined Average</i>	\$6.0	1,745	\$2.3

This table compares Direct Buy and TPP installations recorded in the CSI database by cost per watt, calculated by dividing the given total installation size by the total cost.

¹⁸ It is important to remember that this cost per watt measure is not the rate that jurisdictions are paying to the third party provider, just a derivation of the installation total cost by its total energy production rating in watts.

Figure 17: Percent of Installations by Cost Per Watt

The line graph shows overall project cost, as a ratio of total size. The blue line (Series 1) shows directly purchased projects and the yellow line (Series 2) shows TPP projects. A sample of 858 and 377 installations was used for directly purchased and TPP respectively. Source: CSI produced graphic.

Cost varies more for direct buy projects than TPP projects, when excluding extreme outliers, as the box-plot in **Figure 18** shows—though, as shown, there are quite a few cases (outliers) of extremely high cost per watt for both financing models. It is not entirely clear why TPP projects have such extreme outliers.

Figure 18: Installations' Cost per Watt Variance

This box-plot compares direct buy and TPP installations' total cost (in cost per watt), as recorded in the CSI database. The maximum and minimum are shown including and excluding outliers. Cases are considered outliers when they are more than 3/2 times of the upper quartile.

Savings

While the actual *total cost* of TPP installations appears to be lower on average, this does not necessarily translate into *higher savings* for the public entities that invest in them.

Since electricity rates charged to the jurisdiction for leasing and PPA's are not provided in the CSI database, survey responses provide the best measure available potential savings in energy costs. Respondents were asked to report what level of savings they expect to see from their solar over the life the project, measured in percentage terms (see **Table 11**). Across the board most jurisdictions expected to attain significant savings—median response was 11%-30%. However, analysis of survey data reveal that that while over half of TPP projects were anticipated to result in savings of 11%-30%, only 18%

were expected to achieve savings of over 40% compared to nearly half of the direct buy projects. Additionally, three of the TPP projects were anticipated not to provide any savings at all. While sample sizes are too small to be certain, the differences appear to be significant. Taken together, it appears that directly purchased projects have a slight edge over TPP projects for producing the greatest overall savings, based on surveyed jurisdictions' experiences.

Table 11: Expected Project Savings

Expected Savings	Direct Buy		Third-Party Provider		Total Projects
	# of Projects	% of Projects	# of Projects	% of Projects	
None	0	0%	3	17%	2
1%-10%	4	17%	4	22%	7
11%-30%	5	21%	8	44%	14
31%-40%	2	8%	0	0%	2
Over 40% in savings	11	46%	3	17%	14
Don't know	2	8%	0	0%	2
Total	24	100%	18	100%	41

Surveyed jurisdictions were asked what savings they expected over the life of the project as compared to status quo energy costs.

Like any financial investment made based on economic forecasting, actual payback varies with the market. The decision whether or not to move forward with a solar project is usually made based in part on a forecast of what the price would be for the energy source being replaced. Actual prices could turn out to be higher or lower than forecast. Furthermore, how price fluctuations translate into cost savings for a jurisdiction may depend on price agreements incorporated in TPP contracts. In two of the three TPP projects where no savings were reported as being accrued from the project, it was a result of grid utility prices not rising as forecasted.

For example, California Polytechnic State University (Cal Poly) made a PPA with SunEdison in 2006, when general grid electricity rates had consistently been rising for over a decade at a rate of 5% or 6% per year. The University agreed to 20 year contract with an initial rate paid to SunEdison of \$0.145 with a \$0.0185 increase in rate (aka escalator) each year over life of the agreement. As shown in the forecast model, **Figure 19**, created by the University at the time, those rates were expected to result in significant savings starting six to nine years after the commencement of the project.

However, the intervening years have seen an unprecedented drop in the price of natural gas, a shaky economy, and other factors affecting the energy market and resulting in grid electricity pricing staying roughly flat for a number of years. In today's market, many jurisdictions have negotiated lower starting rates and escalators. Since Cal Poly had locked into a 20 year rate escalator, the University is currently paying more for electricity from its solar panels than it pays for electricity from the grid. Of course, the same phenomenon could easily have occurred in the reverse, had grid rates escalated at a faster pace than expected.

Figure 19: Comparative Rate Forecast
California Polytechnic State University, 2006

A forecast prepared by Facilities Service Department of Cal Poly conducting a forecast analysis for anticipated savings of their solar PPA in 2006. Shared by Dennis Elliot, Assistant Director, and Facility Services Department.

Ownership Structure and Sizing

One clear difference between TPP and direct buy projects, evident from both database analysis and survey responses, is relative production size. TPP solar projects are significantly and consistently larger than direct buy projects, as shown in **Figure 20**.

Figure 20: Installations' Size Distributions by Ownership Structure

Size distribution, in quintiles, of installations recorded in the CSI database 2007-2012, and split by ownership model for comparison.

This differentiation in size can be explained from a couple of perspectives. The first is the affordability of this financing structure. That is, since PPA's and Leases don't require upfront capital, they can allow jurisdictions to size upward based on siting availability and overall solar capacity goals, without the limitations of capital equity or securing extensive bonds or grants.

The second perspective, however, is the dominant explanatory factor. TPP's feasibility is limited on the low end by size considerations. Small solar projects are not feasible as TPP's due to 1) high fixed soft costs and (2) creditor reluctance to fund projects with smaller returns on investment.

As established earlier in this thesis, there are legal costs and staff time involved in setting up these more complex financial agreements. As Jason Coughlin of NREL simply explains: "it's just as much work on the banking and legal side no matter the size" (personal correspondence, October 10, 2012)

Ben Peters, the leading market analyst with REC solar suggests that the rule-of-thumb used in the last five years for determining whether a TPP project is feasible is that the installation must be at least 100 kW, or a total cost of at least \$750,000. After all, every TPP transaction requires legal work that will cost approximately \$50,000-\$200,000 for contract preparation and negotiation (Peters, personal correspondence, February 22, 2013). It's a very specific type of soft cost, and has become a major market barrier. The minimum size required is getting higher; Peters predicts that projects initiated in 2013 funded through TPP arrangements will have to be sized at well over 1 MW to get attention from most financiers unless more capital and tax equity providers become comfortable investing in solar via TPP.

Method 1 analysis of the CSI database suggests that TPP projects developed by California's public jurisdictions are no exception to this rule. While TPP installations range a great deal in size, the vast majority are over 100 kW, as shown in **Figure 20** above.

Survey responses show an even more extreme reflection of the rule, as shown in **Figure 21**, below. Nearly all jurisdictions' solar projects¹⁹ are over 400 kW.

¹⁹ Creditors will make decisions on the *project* level of solar acquisition even if actual PPA's are made on the installation level.

Figure 21: Project Size Distribution by Ownership Structure

Surveyed jurisdictions' solar projects by general size categories provided in the survey.

Smaller projects offer lower margins of profit for investors. Solar companies that offer TPP arrangements, partner with a crediting organization (typically banks, although there are a handful of organizations that specialize in solar financing). Because of the smaller potential profit margin, the financial backers of TPP projects just aren't interested in financing small projects. It was this very reluctance of financial backers to give credit that drove Congress to approve an upfront Treasury cash grant equivalent to the section 48 Investment Tax Credit (30% of a project's eligible basis) in 2009. While the Grant was being offered, many institutions, mostly companies, simply bought and stock-piled PV panels in the amount necessary to meet the grant's eligibility requirement of 5% of project cost, and simply stored them until appropriate sites could be identified at a later date. In 2013 the Treasury Grant equivalent of ITC is gone and creditors are uninterested in funding small-scale projects. Consequently, meeting a minimum size threshold may be *the* primary key factor for jurisdictions in determining whether a TPP is an appropriate financing option for their project.

There are far fewer size considerations related to financing for direct buy projects, which means that jurisdictions may more often proceed with smaller installations. With lower soft costs and the option to use tax-free bonding options, investors are more likely to view giving credit to these projects favorably. However, even jurisdictions buy their own installations smaller size projects likely face some disadvantages with respect to financing since the same issues of profit margin.

Hybrid Financing

While most jurisdictions will choose to finance their solar project either through TPP or direct purchase—one or the other—a handful of public entities in California and other solar pioneering states have begun to pioneer new hybrid financing models that can take advantage of tax incentives and the low-interest bonding power of public entities.

City of Lancaster's Hybrid Model

While TPP projects have the potential for a number of challenges and pitfalls associated with them, this financing model still provides tremendous potential for allowing jurisdictions to enter the solar market, especially to attain fairly large scale solar arrays. The City of Lancaster offers a particular poignant example of how the TPP model can be used to advantage for a public jurisdiction to attain a large amount of solar and have a large savings margin.

In 2010, the City of Lancaster initiated a PPA for city facilities in parallel to facilitating development of a large utility solar project in the nearby Antelope Valley. The city partnered with SolarCity to install 1.45 megawatts. With new federal and state incentives at a high point that year, Lancaster was able to negotiate a low \$.10 kWh and escalator with Solar City--\$.07 cheaper than the grid price of \$.17 kWh they were then paying to Southern California Edison.

Cash-strapped from the recession, the city was looking for other ways to save, and taking advantage of Deputy City Manager Jason Caudle's financial expertise garnered from his former career as a stockbroker, the City realized that if the city became its own utility, generating and selling solar energy, the revenue potential and tax savings could be huge (Heather Swan, personal interview, April 16 2013). That same year the City became its own utility and passed a Resolution forming a Joint Powers Authority, which authorized Lancaster to sell energy. In partnership with SolarCity, this put Lancaster in a position to take advantage of the 30% federal investment tax credit offered at the time, the CSI, and low-interest municipal bonding authority.

Next, armed with expertise from its own project and many resources at hand, the City approached the Lancaster Unified School District and Eastside Union School District to help them build a solar project. Although still partnering with SolarCity under a PPA agreement, in this agreement, unlike most PPAs, the power from the installation was purchased by the School Districts. Instead, Lancaster's Joint-Powers Authority purchased in one lump sum, all the power that would be produced by the 25 installations over the life of the project, through low-interest bonds, funded by private equity totaling just under \$27 million. The Authority then sells the power back to the Districts for \$.125 kWh. By utilizing this 'cheap' money available through low-interests loans available to them, the City was able to generate a revenue stream in selling the power back to the school districts, even without marking up the price. The deal is expected to save the School Districts an average \$300,000 a year. The City of Lancaster projects a \$16.8 million yield over the life of the bond (Skolnick, 2012). The structure that the City of Lancaster has developed is a unique model.

Other jurisdictions in Colorado and New Jersey have utilized a slightly different funding model that uses both private and public incentives. Often referred to as a “Bond-PPA hybrid” or Morris Model after the project by Morris County, New Jersey, in these case the jurisdictions have issued a government bond at a low interest rate and transfers that low-cost capital to a developer to utilize for construction in exchange for a lower PPA price. According to a study by the National Renewable Energy Laboratory, jurisdictions that have implemented this model have achieved notable energy cost savings as compared to projections of their local electricity rate; the four portfolios that have been finalized to date have saved between \$3 million and \$14.6 million on a net present value (NPV) basis (Cory et al. December 2011).

While most jurisdictions will not want to take the major step of becoming a utility and selling energy, like Lancaster, or create a complex Bond-PPA hybrid like Morris County, these cases illustrate how jurisdictions can leverage multiple tools to get the most out of a TPP arrangement.

System Size and Feasibility

Size and Cost

As discussed in Section previous sections, it is clear that TPP projects benefit from surpassing a certain size threshold. Basic economic theory and overall trends in the solar market suggest that solar is subject to economies of scale. CSI data supports this theory, though the marginal dip in price appears to be moderate. **Figure 22**, created from a random sample of just over 1,100 government host installations, demonstrates a slight decrease in price per watt as a system size goes up in size. Variation in price also appears to result in less variation in cost; installations with costs per watt that deviate more than

\$5 dollars from the mean drops are less frequent as size approaches 100 kW. Although, this also likely reflects the smaller number installations overall, more of which are TPP projects (TPP projects are larger and thus dominant the upper spectrum), which have already been demonstrated to have total costs that vary less overall.

Figure 22: Cost Comparison by System Size

This scatter plot is a random sample (1,119) installation in the filtered data set, 359 of which are TPP funded. Blue dots represent a single project, while gold squares represent the mean cost per watt for the system size shown on the X-axis. Costs for systems owned by third parties versus host customers (\$/watt) cannot be directly compared. Program Year is set by the first of the following reservation dates: "Reserved Reservation", "Confirmed Reservation" or "Pending RFP". "Range" only includes projects that have an assigned Program Year. "All Years" also includes projects which have not yet been reserved. *Source:* Figure produced by CSI Solar Statistics.

Considering the advantages of larger installation sizes, it isn't surprising that national market analyses are finding that the average non-residential solar installation has been increasing in size from year to year (see Sherwood 2010, 2011, and 2012). According to the 2011 report by the Interstate Renewable Energy Council, the average size of a distributed PV installation grew by 46% in just one year (Sherwood, 2012). However, Method 1 analysis of California's public entity installations from 2007 to 2012 shows a slightly more complex picture of growth trends. As shown in **Figure 23**, the average installation size has fluctuated since 2007, with no clear trend. California's initiated

projects do generally reflect size growth seen across the country between 2009 and 2011 but the average size dropped significantly for 2012. The drop in 2012 may be the result of lowered incentives from both the CSI rebate program and the Federal tax incentives with the end of the 30% ITC Treasury Grant, which is discussed more in the State of the Market Section.

Figure 23: Average Installation Size by Year

The line graph (top) depicts the average size of all public installations in the CSI database by year. The corresponding table (bottom) relates the number of installations included in each average and the standard deviation.

Figure 23 also breaks down year-over-year trends by size categories, revealing that the number of very large installations—those over 400 kW—does not shift much across the 6 years, though the number of small projects shrinks considerably after 2009. This supports earlier discussion that small scale projects are becoming increasingly infeasible

due to disinterest from creditors. However, it also may speak to an upper limit, as well. Despite a general trend upward in size, the number of very large projects remained virtually the same.

The lack of a clear trend up in installations over 400 kW may be the result of several factors, including siting limitations (discussed in the next Section), and the need to match capacity to on-site demand, in addition to the continued challenge of paying upfront costs.

It is most cost effective for a jurisdiction to match a solar installation to the site's electricity load. This is because of the way solar is billed by the utility. Under current net-metering laws, when a jurisdiction puts more power into the grid than it uses, net, the local utility is required to pay back for that power to the jurisdiction. However, the utility is required to pay at a wholesale rate, which is much lower than the typical customer rate paid. Thus, a consistently overproducing system is essentially paying back less for the marginal production over the site's electricity—paying back less on the additional solar panels that are 'overproducing' for the site. Thus, a rule of thumb for solar installation sizing is about 70% of the site electric load (Julie Benabente, personal correspondence, April 15, 2013).²⁰ With a limited number of sites to choose from jurisdictions are limited on the upper end by the electricity loads of those sites.

²⁰ The 70% rule has to do with solar companies' goal to offset a maximum—SolarCity's goal is 90%—of the bill, which equates to about 70% of the electricity usage.

THE SITING CHALLENGE

The viability of a solar installation is highly dependent upon the physical site characteristics. Siting will have influence on generating efficiency, project sizing, design, accessibility, and environmental impacts. For jurisdiction staff planning a solar project, identifying and evaluating sites is undoubtedly the task where extra effort and careful consideration will pay the most dividends in savings and avoided pitfalls.

When asked about selecting sites for their solar project, staff interviewed described an in-depth process that usually involved the collaboration of multiple departments and sometimes outreach to the public. Combining the internal knowledge of engineers, planners, designers, and lawyers, as well as solar contractors, may be necessary to adequately address all the characteristics that should be considered for optimal installation siting.

Site Characteristics to Consider

Characteristics to consider for site selection include a wide variety of variables, which can be roughly broken down by category. The front-line consideration is the actual **physical area** that is available, shade-free, and able to accommodate the panels and underlying infrastructure. Also part of the evaluation should be the **electricity load** of the site. There are important peripheral **use** and resource considerations relating to the site as well, such as surrounding land uses, public attitudes and safety, accessibility, and environmental/historical resources that might be impacted. Finally, there are **planning considerations**, and “locking in” a site to a particular use for 15 years or more.

Physical area. Physical characteristics are the most prominent aspects to consider when choosing sites for solar production. As a rule of thumb, ground-mounted arrays on flat

(see **Figure 24, left**), unused (often called ‘greenfield’) land are the simplest and lowest cost type of installation (Dennis Elliot, personal correspondence, November 10, 2012).

Figure 24: Ground Mounted Installation Types

Examples of ground-mounted solar

Of course, various factors, from availability of land, to desire for higher density of land use, to energy needs can make the use of greenfields for solar development undesirable.

One rung up from ground mounting in terms of simplicity and cost are shading structures, where solar is placed on top of raised structures that can double as protection against elements in a parking lot or work yard (see **Figures 24, right**). As shown in **Table 12**, nearly a quarter of jurisdictions utilized such shade structures for at least one of their installation sites.

The most common siting option, however, was on roof of a facility, most frequently a building with office-like uses such as City hall, administrative building, or library. Other survey respondents reported having installations on non-office facilities, such as recreation facilities or waste water treatment facilities, which are a distinct category here because they frequently have atypical energy usage patterns.

Table 12: Survey Respondents Siting Locations

Site	%
General/Office Building	27%
Parking Lot Shading Structure	24%
Ground Mounted	19%
K-12 School Building	13%
Recreation Facility	7%
Fire Station	4%
Vehicle Yard/Parking Structure	3%
Wastewater Treatment Plant	3%
Other (<i>siting type given only once</i>)	6%

Respondents were asked to select the type of location of their solar installations. In some cases this included multiple installations with different types of siting.

When considering a rooftop installation, facilities management or public works departmental staff should be consulted. These department's staff often maintain information as to building including the maintenance schedule, roofs' age, condition, design, materials, and carrying capacity; all factors that should be considered in assessing appropriateness for PV installation. It is all these varying factors that can make rooftop solar more expensive than either parking lots or greenfield installation, both of which allow for greater uniformity. Of course, buildings do allow for the solar to be sited on otherwise unused space (roof). Also, there is a guaranteed and significant electricity load in the building itself.

It is good practice to choose facilities that are new or have been re-roofed and are not slated for any major renovations, since the roof must remain in operating condition for 20 years or more while the solar panels remain operational. Consequently, siting panels on a newly built facility may be easiest. However, only about 13% of jurisdictions were able to exercise that option. Likely reasons for this are twofold: new facilities coming online for public jurisdictions occur infrequently, and as generally more efficient structures, the provided energy savings may be lower than for other candidate facilities.

Many staff confessed having had deep concerns about the wisdom of siting an installation on a new roof for fear of damaging it. The fear is understandable as nearly all mounting designs require, essentially, punching hundreds of holes into the roof's top surface (see **Figure 25**). However, none of the surveyed jurisdictions ultimately experienced any problems relating to this issue, nor does review of literature raise it as a common problem. None the less, some roof surfaces tend to be more suitable for installations—metal materials, and large areas of flat surface that are free of shade-causing mechanical equipment.

Figure 25: Installation Racking Design

Examples of what a typical rooftop mounting system looks like.

Source: Cal Poly San Luis Obispo, *Engineering West Building Solar Electric System Design* document prepared by SunEdison.

Another consideration for choosing a site sometimes overlooked is weather and hazard exposure. High wind speeds can stress even concrete with high psi ratings. Areas with high fire or other natural disaster risk can jeopardize the installation and raise (already frequently onerous) insurance premiums (Cory, Brendan Canavan, & Ronald Koenig, 2009).

Electricity Needs. Along with its physical characteristics, a site's electricity loading can have a significant impact on project sizing and cost. The size of the solar array a site can accommodate is often limited more by electricity usage patterns, than by the physical area available. Because of how net-metering is calculated, systems should be designed to never exceed electricity need.

In keeping with this rule, it is beneficial to select sites where energy efficiency retrofits have already taken place. Energy efficiency upgrades can reduce a facility's energy usage by as much as 50%, a reduction that would essentially "oversize" the solar installation on that site after the fact, and reduce the installation's provided savings.

Use. A potential site for solar should be considered also within the context of its use, and nearby uses. When asked about siting issues that had arisen, staff brought up use and resource factors much more frequently than direct physical characteristics.

One key use factor is public access on the site. Safety is an issue at publicly accessible sites. This is especially important for ground mounted PVs since they are more directly visible and accessible, but even roof-mounted solar frequently has wiring and other equipment that is down at ground level. Ways to mask or enclose equipment may become an issue where there is a high level of public access to avoid damage to the equipment and reduce safety risks. Likewise, some jurisdictions have even experienced theft of solar panels and equipment on publicly accessible sites.

Jurisdictions should also consider whether the selected site will raise objections from the public for aesthetic reasons. Certain facilities open to the public may require community noticing and outreach to ensure the acceptability of any proposed design. And with all development, stakeholder objections may necessitate changes to the process or design.

For example, in choosing to site several installations as shading structures in much-loved city parks the City of Palmdale project lead, Benjamin Lucha, coordinated extensively with stakeholder group Friends of the Parks and the solar contractor to develop design features (See **Figure 26**) to satisfy aesthetic concerns—a process that did require a reduction in money savings for the City.

Figure 26: Specialized Design Elements for Installation Palmdale

The design of the solar installation structures used in Palmdale's public parks. The green coloring and decorative features were necessary for siting there, allaying public aesthetics concerns.

Jurisdictions should also consider other legal restrictions of a site. Some sites may contain biological or historical resources (heritage trees or wetlands, for example) that could inhibit installations or require a PV installation (usually not enough to trigger formal CEQA requirements) to under an environmental impact assessment.

Additionally, many sites are bound by legal restrictions on the types of uses that may occur on publicly owned lands. Since TPP's are considered a private activity for tax purposes, issues of private use on public lands arise. Most municipal bonds, for instance, have a Private Activity Percentage requirement that states that no more than a certain percentage—typically 5% --of land bought with bonds can be used for private activities.

Jurisdictions should work with their finance department to determine whether the site(s) in question are affected by any bond issuances.

Land use planning. A final set of considerations in siting project installations relate to long-term land use planning. In most cases, PV systems should be expected to operate on-site for 20 or more years—a time equivalent to most General Plan horizons. The installations limit, or entirely eliminate, alternative development that could occur at that site. Thus, in choosing sites, project planners should consult the General Plan, Specific Plans, and any other documents that might indicate whether the arrays can be consistent with the community’s long-term development plans.

For instance, in considering additional sites for installations on campus, project lead Dennis Elliot rejected several peripheral parking lots that might otherwise have been ideal for solar shading structures because the campus’ Master Plan slated them for siting future dormitories.

Methods of Site identification. Due to the plethora of factors to consider, it is helpful for jurisdictions to develop a quantitative method for selecting sites. The City of San Jose, for instance, has created a detailed ranking system for identifying and ranking sites that are most appropriate for PV. Cal Poly developed a campus wide map, shown in **Figure 27**, which identifies potentially appropriate sites and eliminates inappropriate ones, thereby streamlining siting decisions for all future solar projects.

Figure 27: Campus Wide Solar Installation Siting Availability Map for Cal Poly University

Cal Poly staff developed this map to identify areas that are appropriate for solar (green) and unsuited (red), due to any number of factors, for solar.

THE SOLAR PROVIDER: SELECTING AND DEALING WITH YOUR CONTRACTOR

The solar PV field is relatively new, at least within the current political and market context, and as with many new industries fields a large number of start-up enterprises. Many of them are in California. The CSI database reveals that jurisdictions contracted with over 250 separate companies since 2006 for their solar installations (see **Table 13**). In most cases, the contracting company was also the installing company.

Table 13: Top 10 Solar Companies by Number of Installations

Rank	Company	# Installations	% Total Market
1	SolarCity	185	11%
2	SunPower Corporation	163	9%
3	Chevron Energy Solutions	149	9%
4	PsomasFMG, LLC	64	4%
5	Cupertino Electric, Inc.	48	3%
6	Real Goods Solar	46	3%
7	Sun Edison LLC	45	3%
8	Stellar Energy GP, Inc.	45	3%
9	Main Street Power Company, Inc.	43	2%
10	IEC Corporation	43	2%
	Total	831	49%°

Shows the top solar companies in California based on the percentage of total installations initiated for public entities throughout the 6-year period in the CSI database.

These companies range widely in size, geographic service area, and expertise. The ten top solar companies control just under 50% of the California public sector market over the six year period. The most dominant by far are SolarCity, Sunpower Corporation, and Chevron Energy Solutions. As stated in Method 2 section, surveyed jurisdictions' projects generally reflected a similar breakdown in solar companies. Interviews were conducted with jurisdictions that had utilized each of the three dominant companies.

For the most part, jurisdictions indicated they were, with some small reservations, very satisfied with the performance and relationship with their solar provider. Nonetheless, when asked about tips they'd want to share with other jurisdictions looking into solar, the most frequent response from interviewees related to selecting and interacting with the project solar provider.

This is not surprising: jurisdictions depend on the solar contractor to deliver on a major capital investment in a specialized, and fairly new, rapidly-evolving, field. So what factors make for a right or not-so-right contractor? Staff interviewed raised several issues to look for in a solar contractors and their proposals, including realistic rates/costs in proposals, demonstrated expertise/experience, flexibility on design, and likelihood of bankruptcy. These issues are discussed further below.

Requests for Proposals (RFPs)

Often, the first step in getting the right solar provider is soliciting proposals for the project. California state law (California Government Code Section 4217.10 to 4217.18) does not require that a formal Request for Proposals (RFP) be conducted for energy efficiency and solar projects. The intention of the law is streamlining the process for both the jurisdictions and contracting companies, since the formal RFP process can sometimes be arduous and time consuming. Experts at the National Renewable Energy Laboratory, however, advise that jurisdictions considering projects of 500 kW or more do go through a formal RFP process as the best practice. The project's profile is likely higher for larger projects so an open process is advisable. Additionally, there is likely to be greater ranges of savings and services offered by different providers with a larger project. Smaller projects may draw few responses from developers due to sizing and credit related issues.

Thus, for smaller sites, jurisdiction should potentially consider either seeking a cooperative procurement option discussed further in the next Section or contact developers directly to receive bids without a formal RFP process.

Among those jurisdictions surveyed, about two-thirds did issue an RFP for their projects (**Figure 28**), from which they reported receiving proposals from generally between two and five contractors.

Figure 28: Jurisdictions' Use of RFP

Surveyed jurisdictions were asked if they put out an official Request for Proposals for the solar project.

Writing the RFP: It is important to have an RFP with clear, accurate, and detailed content. The primary goals of the project should be clear. A jurisdiction's primary goals might include making the arrays a demonstration project, creating solar jobs, or reducing greenhouse gas emissions. Different goals will influence what is the most desirable outcome of the procurement process.

Level of detail in the RFP is important. Too little information about project goals and site details inhibit solar contractors from developing appropriate and realistic proposals. It is also worthwhile to establish a realistic idea of project sizing. To do this, the jurisdiction should do a comprehensive assessment of potential sites and facility energy

needs. A number of resources exist to aid in estimating solar output requirements. For instance, NREL has a free online tool: In My Backyard (IMBY) PV System Analysis, a graphics-based tool that uses system size, location, and other variables to predict system output for PV systems.

Conversely, too detailed or restrictive RFPs can result in a dearth of bids or unacceptably high bids. Some overly restrictive elements in an RFP can include restrictions on site access, bonding requirements, mutual indemnification clauses, and making payments contingent on annual appropriations (Solar Foundation, 2012).

The logistical information that bidders may require to create their proposals should be included. While preference for a specific ownership type may be included as part of the jurisdiction's goals, it is useful and fairly common for the RFP to allow for bids that utilize different financing options.

Key elements to include in an RFP will of course vary according to jurisdictional goals and financing structure. However, several key provisions are consistently put forward as important elements to consider. It is not the goal of this thesis to provide a comprehensive list of provisions to include in contract content²¹ but instead to discuss those provisions highlighted as especially important or frequently neglected by jurisdictions that have gone through the process, from Methods 2 and 3 of the retrospective analysis. Considering the greater complexity and long-term importance of TPP contract agreements, most of the provisions are most relevant to power purchase

²¹ Several guides have already been published regarding this topic, including a comprehensive PPA checklist produce by NREL, and various caches of sample and example contracts are readily available.

agreements and lease-to-own contracts. Key elements highlighted include strong warranties, maintenance agreements, retention of Renewable Energy Credits, buy-out options, options to add additional sites, and end-of-life procedures.

Warranties should establish who is responsible for operation and maintenance of the installation, including acquisition of replacement parts, and general upkeep such as cleaning. For rooftop installations, the RFP should also clearly require that the contractor be required to ensure that the installation of rooftop solar energy systems will not adversely impact roof integrity or violate existing roof warranties. For PPA's the required warranty should potentially include details about access to the system and deal with which equipment onsite. San Jose, for instance, had to clarify whether the City or solar company owner was responsible and authorized to maintain and repair outdoor area and security lighting on the site of several of its larger, ground-mounted installations. For lease and direct buy projects, it may be appropriate to request a detailed maintenance and repair agreement, which includes who is responsible for which costs and over what time periods. The Live Oak School District developing a separate and detailed maintenance contract with Chevron Energy Solutions for their 15 year lease-to-own project. The maintenance agreement was kept separate to leave open the option for the District to consider other companies for that long-term working relationship.

Several interviewed staff emphasized the importance of ensuring solar contractors have sufficient financial capacity. They should be required to submit documents that adequately and accurately demonstrate their financial capacity to cover any applicable up-front design and installation costs. Contractors should be able to document financial statements and their ability to secure credit from a reliable investor.

Notably, solar providers are also constantly adjusting to the rapid developments in the field. Companies, like Chevron with school district installations, have begun to develop specializations and are incorporating new models and techniques that can facilitate the process or save money for both parties. Jurisdictions should look for contractors that innovate, as well as providers that have developed specific models of operation that might be a best fit for them.

Contract Issues for TPP Projects: For TPP projects there is also the issue of insurance coverage, which is typically a significant portion of upfront cost. Some jurisdictions are able to provide their own onsite insurance, but it is standard for that cost to be covered by the solar contractor—a line item that should be clearly assigned in the RFP.

The ownership of the installations' Renewable Energy Credits (RECs) is an often overlooked and misunderstood factor. RECs are typically credited to the *owner* of solar installations. However, a jurisdiction may benefit from attaining the RECs both for their direct financial value, but also to demonstrate renewable acquisition for compliance with local ordinances, grant requirements, or most likely State requirements.²² REC's essentially operate as the 'currency' for complying with state renewable requirements. While renewable capacity has not yet been enforced by the State for local jurisdictions under the Scoping Plan, it may be beneficial for jurisdictions to retain the RECs as a contingency; to ensure they get credit for renewable capacity (even if it's technically owned by a third-party) should it be required under AB-32 or other state requirements coming down the pipeline.

²² Proof of solar attainment could be required by the state if a jurisdiction becomes its own utility provider or CCA and therefore must meet the RPS requirement. Additionally, holding RECs could be used to demonstrate a part of compliance with compliance with AB-32 Greenhouse gas reduction requirements.

Also important is establishing if and when the jurisdiction would like to have the option to buy the installations from the solar provider. Such buy-out clauses typically occur at the 6-year marker (the close of federal tax subsidy benefits) and at the end of contract. However, a number of jurisdictions surveyed also chose to have flexibility for options to buy-out at various other intervals and included details about the cost of doing so, either with a certain depreciation reduction or at market rate. Depending on its goals, a jurisdiction may also want to include clauses for end-of-life procedures—how the panels and other equipment will be disposed if they will not remain in operation after the life of the contract.

Selecting a Provider: An issue raised by several staff interviewed, and re-iterated by representatives of the solar industry interviewed, was the problem of proposals with unrealistic promises. That is, solar companies proposed projects with a total cost or rate (in the case of TPPs) that did not actually include all costs or were simply unable to deliver those rates in the end. Ben Lucha, the Senior Administrative Analyst with the City of Palmdale explained that their first RFP winner promised the highest savings with a lease-to-own proposal. But when the company came back with a full pro forma for the project, the return on investment for the City would have occurred very late into the contract with the City losing money compared to grid rates for many years (Lucha, personal correspondence, May 1 2013). Ben Peters, a representative from REC Solar, asserts that the use of unrealistic rates by competitors in proposals is so common that REC does not even respond to RFPs anymore, depending entirely on the direct and informal approach of clients.

Similarly, Soquel High School in Santa Cruz had difficulties after the project developer Morgan Stanley wanted changes in the contract requiring the School District to assume insurance liability on the equipment and drop requirements that contract workers be paid a prevailing wage (Brown, November 2008). Such insurance premiums are high cost, and can represent approximately 25% of the annual operating budget and may be as large as 25% to 50% of the project installed costs (Cory, October 2009).

Keith Houchen, Director of Buildings, Grounds, Maintenance and Transportation at Live Oak School District, offers this advice: “choose larger companies, since they’ll be the ones to have the resources if something breaks or goes wrong.” Houchen explains that, considering the size and demand of his district’s project, anything unexpected would very likely end up bankrupting a small company.

Indeed, the solar market is still fairly unstable, with bankruptcy a fairly common occurrence. The online blog Greentechmedia.com maintains a list of solar firms that have become insolvent. Since 2009, more than 70 solar companies went bankrupt, closed, or were acquired. While for direct buy projects this can be an inconvenience for getting a hold of compatible parts for maintenance, for TPP projects, the prospects of the solar owner of their installations going out of business could pose a true legal debacle.

To avoid these kinds of issues concludes, San Jose Energy Officer, Julie Benabente, jurisdictions should take the time and effort to do their homework on solar providers, and vet them carefully before making a decision. In addition to attaining information about a company’s resources and past projects, it is also useful to identify specific expertise. Some companies specialize in a particular installation design, ownership structure, or even jurisdiction type. For instance, Chevron Energy Solutions (CES), is one of the

nation's largest installers of solar energy systems for education institutions. Over the past decade, the company has installed hundreds of solar arrays, most often through a lease-to-own financing structure, for k-12 school campuses. As a result, CES has developed an entire model for solar development with districts that meet the California Division of the State Architect's strict design and construction rules, utilize school specific grants, (such as QZABs and QECBs) and even has resources to help teachers with curricula that promote energy consciousness in connection with the installations. Such lock-and-load models developed by companies for a specific application can mean avoiding unexpected pitfalls associated with regulatory standards, can help facilitate attainment of financing (CES almost always partners with Bank of America to finance its school projects), and provide lower pricing specific equipment (through bulk purchasing deals).

Interacting with the Solar Provider

Interviewed staff also emphasized effective communication and negotiation with solar providers as an important factor for a successful solar project. As is the case in working with contractors on large capital projects, jurisdiction staff should clearly know their project goals and carefully assess contract and agreements to ensure critical elements are included. Ben Lucha knew that for Palmdale's solar project, they wanted to make sure the City was able to keep the renewable energy credits (REC's). He also wanted to make sure that several of his installations, such as carport shading structures in the City's well-loved municipal parks, were aesthetically pleasing. Lucha notes that he had to be very assertive with the City's solar contractor, PsomasFMG, to get the elements into the contracts. Psomas—like nearly all solar companies—had a standard practice of retaining the REC's. Consequently, keeping ownership with the company kept sneaking back into contract language, and Lucha had to be diligent to ensure the agreement ultimately said

what the City and the company had agreed to. Making the solar car shade structures deviate from the standard dull grey industrial steel design to a softer green color with decorative elements, required Lucha to coordinate between public stakeholders and the solar company, to provide example design elements and adapt those elements to fit within the budget the City and Psomas could agree on. Lucha notes that those kind of important details “take a lot more time and effort than people recognize.”

Solar companies have their own standard practices, preferences, and bottom lines. Consequently, solar project managers need to be diligent to ensure that jurisdiction procedures and standards are followed and the contract reflects details that will ensure the project meets jurisdictional goals. “Don’t let them push you around,” is the advice of Live Oak School District’s Keith Houchen.

THE NEXT BIG THING: COOPERATIVE SOLAR PROCUREMENT AND PROJECT DEVELOPMENT

Cooperative procurement and project development is emerging as an important tool for jurisdictions to minimize the costs and technical barriers to solar energy acquisition. In a nutshell, these models are the partnership of two or more jurisdiction to collectively negotiate, purchase, and contract for solar projects. Aggregating demand can unlock volume discounts from product sellers and collective contract development can spread soft costs among multiple installations and participating organizations. The solar market is no exception to these potential benefits and can play a critical role in mitigating the primary barriers to jurisdictions' solar acquisition: upfront costs, RFP development, project planning, contract development, site assessment etc. A study of two California cooperatives completed in 2012 found that the quantified benefits of cooperative arrangement include an incremental 10% to 15% reduction of energy cost, compared to individual projects; transaction and administrative time reduced by 75% for each participant; and highly competitive contract terms. Over the six-year period, such collaborations have been initiated across public agencies, educational organizations, and jurisdictions within the same region. A number of the surveyed jurisdictions surveyed had participated in a collaborative for their solar project (**Figure 28 and Table 14**).

Table 14: Lead Cooperatives and Lead Agencies

Cooperative	Lead Entity
Small Cities Climate Action Partnership	City of El Cerrito
Statewide Solar Power Purchase Program	Department of General Services
Merced County local governments	Merced County
Kern County School Districts	Kern County Education Office
Regional Renewable Energy Procurement Project	Joint Venture Silicon Valley

Figure 29: Survey Respondents' Solar Procurement/Project Cooperatives

The pie-chart (bottom) shows that almost 1/5 of surveyed staff indicated their jurisdiction was, or is currently, part of cooperative arrangement. In some cases, the cooperative included additional working relationships beyond equipment procurement, such as policy and plan development. The Table (top) displays the name and lead entity of each cooperative.

These collaboratives range greatly in size and structure. For instance, Cal Poly participated in an institutional collaborative spearheaded by the California General Services Department (DGS) that included state owned executive branch facilities, such as prisons, as well as the California Universities' system facilities. For this cooperative, Cal Poly and dozens of others institutions applied with a project size and installation to be entered into a 'qualified pool.' Once in the pool, the DGS issued RFP's on their behalf and when cost effective proceeded with lease agreements. Final contracts were made between the solar provider and the University. To date, DGS has installed over 19 MW of PV in this way.

On the other end of the spectrum is the Small Cities Climate Action Partnership, a joint procurement process by just four small jurisdictions—the Cities of El Cerrito, Albany, Piedmont, and San Pablo-- all with populations under 40,000. To overcome barriers caused by their small scale and limited staff and resources, in 2010, the City of El Cerrito initiated a two year partnership with the three other cities to achieve GHG reductions.²³ The cities partnered for development of Climate Action Plans, solar procurement, energy efficiency and other projects. Though a fraction of the size of cooperative arrangements like DGS', the Cities partnership still helped them to streamline their separate planning processes by sharing information, identifying opportunities and increasing purchase volumes for solar panels and other energy equipment. In addition, the partnership helped each jurisdiction overcome the size issue of attracting bids and creditors to back smaller installation.

Interviewees that participated in a cooperative for their solar projects generally affirmed the benefits asserted in the literature, though not without some mention of hitches and challenges relating to that process. As with any inter-jurisdictional effort, carrying out a cooperative solar procurement project has its own challenges. The cooperative procedures most take into account differences in jurisdictional requirements in requesting proposals, purchasing, permitting, and siting. Note for instance that organizations like schools and jails frequently also have additional safety or procedural requirements from an overseeing agency. Cooperative projects also require strong and dedicated leadership that can persist in commitment for several years. The success of a cooperative is often

²³ Small Cities Climate Action Partnership. (February 22, 2013).

dependent on the drive of a lead agency or even just one internal champion. The original DGS- led project, in which Cal Poly participated, essentially evaporated when the lead person at DGS left his position for another. Cal Poly's project was not set back in motion until the CSU Chancellor's office took up the reins for remaining State University projects.

Several useful resources exist that can aid jurisdictions interested in forming, operating or joining a successful cooperative. The CSI has funded the Solar Energy and Economic Development Fund (SEED), a project to develop and test new processes that combine Collaborative Procurement with a Revolving Fund. SEED Fund has the goal of bringing online at least 5 MW of new public PV, and is currently in the process of soliciting proposal for dozens of jurisdiction participants in Sonoma, Napa, and Marin Counties. In 2011, the World Resources Institute in Partnership with the JointVenture, and Optony Inc. (which has specialized in collaborative solar investments) published a best practices guide, including a 12-step guide and a case study from the SEED funded Silicon Valley Regional Solar Project. Other examples of successful collaboratives include the Bay Area Regional Renewable Energy Project, the Silicon Valley Renewable Energy Project, and the Contra Costa Economic Partnership.

STATE OF THE MARKET

This thesis has made mention throughout of the termination or depletion of a number of critical incentives for solar procurement. Indeed, the last five years mark a period of extensive state and federal investment in solar development that may not be repeated in the very near future. This section provides a general overview of the solar market post-2012 both from literature market analyses and the perspectives of 45 jurisdictions whose solar project experience has been reviewed throughout this thesis. It also provides a summary of incentives and funding sources that have been utilized for solar development from 2006 to 2012 and forecasts those that will have bearings through 2020 (while recognizing that such information is predicated in a constantly changing policy and political environment).

California's Public Solar Market (2006-2012)

This last year, 2012, was another year for breaking records. California became the first state to install over 1,000 MW in one year, with growth across all market segments. Public jurisdictions' solar projects accounted for approximately a 10th of that growth. Indeed, solar deployment amongst California's local jurisdictions has grown almost exponentially over the last six years (see **Figure 30**). As of the first quarter of 2013, nearly 500 MW of solar capacity powers public facilities across the state (see **Table 15**).

Figure 30: Public Solar Projects in Sum

The map illustrates public solar projects locations and sizes by zip code, and the line graph size compares the aggregate amount of MW of solar initiated for direct buy (DB) and Third-party Provider (TPP) projects since 2006, from CSI records.

Table 15: Public Jurisdictions Solar Summary Statistics (2013)²⁴

	Totals		TPP	DB
# Installations	1,779		586	1,177
# Completed	1,299		361	852
Total kW	489,949		219,873	270,076
Mean Size	279		387	227
Mean Cost	\$ 1,472,716		\$ 1,931,007	\$ 1,251,552

This summarizes the total number of installations and capacity of installations installed since 2006, based on CSI records.

The rapid volume increase is indicative of booming industry transformed by technological as well as production innovations, and bolstered, undeniably, by a number of newly implemented policies and incentives implemented over that time.

With many Significant among those policy changes are both statewide incentives programs and allowances of new third party provider ownership models.

Funding Sources Utilized (2006-2012)

Billions of dollars in rebates, tax credits and grants were deployed over that time. With advent of third party provider models, public jurisdictions were able access large sums from all these funding sources. Surveyed jurisdictions illustrate the diversity of funding sources that public entities took advantage of. Method 2 surveying asked staff respondents about project funding sources. Those sources have been broken into two categories: (1) grant and bonding sources; (2) incentives and rebates including federal tax credits and SS 1603 cash grants.

²⁴ Totals are those installations recorded in the CSI database and do not include solar capacity outside investor-owned utility territories.

As shown by **Table 16**, the most prominent incentive, utilized by over 80% of jurisdictions, was the California Solar Initiative (CSI) rebate, either as a performance-based incentive or an expected performance-based buy-down. Method 1 analysis shows that the CSI program has doled out nearly \$630 million public entities statewide since 2007. The incentives helped fund 500 MW for jurisdiction solar PV projects. A handful of jurisdictions were also able to take advantage of additional rebates provided by their utility not part of the CSI program.

Table 16: Rebates Utilized

Funding Source	%
CSI Performance-Based Incentive (PBI)	23%
CSI Expected Performance-Based Buy-down (EPBB)	58%
Utility Incentive (other than CSI)	12%
Total	88% ²⁵

Surveyed staff was asked what rebates they were able to utilize for this solar project. In total, 38 jurisdictions reported utilizing these rebates.

Table 17 shows that Tax-based incentives were the second most commonly utilized incentive source, with just over a third (44%) of surveyed jurisdictions, effectively all jurisdictions with TPP projects, accessing the Production Tax Credit or Investment Tax Credit—either as a traditional credit or as cash grant through SS 1603.

Table 17: Tax Incentives Utilized

Funding Source	%
Federal: Energy Investment Tax Credit (ITC)	19%
Federal: Renewable Energy Reduction Tax Credit (PTC)	16%
Federal: Treasury Department 30% Cash Grant	9%
California Property Tax Exclusion for Solar Energy Systems	2%
Total	46%

Surveyed staff of TPP projects was asked what tax incentives they were able to utilize for their solar project. In total, 26 jurisdictions reported utilizing these incentives.

²⁵ This percentage represents the percent of all jurisdictions that were able to utilize rebates. It does not equal the sum of the above categories, since some jurisdictions utilized multiple rebates and thus are counted twice, and removed from the total.

While nearly all TPP projects utilized tax incentives, a large percentage of direct buy projects also depended on loans (59%) and/or grants (30%) to fund their project (**Tables 18 and 19**). Most accessed federal funding through Energy Efficiency Block Grants, Clean Renewable Energy Bonds, and Qualified Energy Conservation Bonds.

Table 18: Grants Utilized

Funding Source	%
Department of Energy Efficiency and Conservation Block Grants (EECBG)	17%
EPA Climate Showcase Communities Grant	6%
Other Grants	7%
Total	30%

Surveyed staff was asked what grants they were able to utilize for this solar project. In total, 17 jurisdictions reported utilizing these grants.

Table 19: Bonds and Loans Utilized

Funding Source	%
Federal Clean Renewable Energy Bonds (CREBs)	17%
Federal Qualified Energy Conservation Bonds (QECB)	9%
General Obligation Bonds	9%
California Energy Commission Energy Efficiency Financing Program Low-Interest Loan	6%
Other bonds or loans	37%
Total	59% ²⁶

Surveyed staff was asked what bonds, loans, and grants they were able to utilize for this solar project. In total, 26 jurisdictions reported utilizing bonds or loans.

Market Environment and Funding Sources (Post-2012)

While some of these prominent funding sources continue utilized by surveyed jurisdictions and many others, the majority are depleted (or nearly so). **Figure 31** shows where the major funding sources stand.

²⁶ This percentage represents the percent of all jurisdictions that were able to utilize rebates. It does not equal the sum of the above categories, since some jurisdictions utilized multiple rebates and thus are counted twice, and removed from the total.

This timeline illustrates the when major State and Federal level rebates, grants, loans, and tax incentives were made available and their expected status through 2016 and beyond based on current funding allocations and policies.

Figure 31: Status of Major Funding sources from 2006 to 2020

The following section describes the state of each of the incentives, starting with California specific incentives, followed by Federal level incentives.

California Solar Initiative (CSI)

The CSI program was established with the State’s Go Solar Program under Governor Schwarzenegger’s “Million Solar Roofs” and authorized 2006 by Senate Bill 1. CSI was provided a total budget of \$2.167 billion. The rebates were made available across all sectors—to residential, commercial, and public sector property owners alike. Funded through a rate fee on electric ratepayers of the state’s three investor-owned utilities (IOUs), its program funds are divided amongst and distributed by IOU’s with goal to install approximately 1,940 MW of new solar generation capacity throughout the state.

While the program was originally set to run through 2016, by January 2013 the program’s megawatt targets have nearly been reached for most of the state (**Table 20**), a result of higher than anticipated application volumes among customers across all sectors. CSI administrators established that incentives would continue to be allotted until funding is depleted not based target capacity. However, the remaining funding is nearly depleted, with solar experts predicting they will run out before the end of 2013.

Table 20: California Solar Initiative Capacity Status and Targets

Utility	Current Step	Initial MW in Step	MW Remaining	MW Under Review
PG&E	10	102.5	34.8	23.94
SCE	9	87.8	86.18	1.96
SDG&E	8	17.3	5.17	1.35

The table illustrates the CSI program totals of installed capacity and program targets for each utility territory as of May 2013. Incentives will be continued past targets until funding is depleted, likely to occur in late 2013. *Source:* CSI Trigger Tracker.

When it finally spends down its remaining rebates, the CSI program will have distributed \$1.95 billion into solar procurement.

Modernization Grants and Proposition 39

In late 2012, California approved by ballot initiative a new incentive to support PV installation.

The initiative, Prop 39, allocates \$2.5 billion to energy conservation programs, funded through tax on multi-state businesses as a percentage of their sales made in California. Half of that money is slated to fund energy efficiency and clean energy projects in California schools and other public buildings over five years. The Governor's 2013 budget proposes to transfer \$450 million of the revenues generated in 2013-14, and \$550 annually for four years thereafter, into a special fund for energy efficiency projects in schools and community colleges.

Production Tax Credit (PTC) and Investment Tax Credit (ITC)

While the 1603 grant is now gone, the standard Federal PTC and ITC tax credits have been renewed and are likely to continue. The PTC was expanded under the American Taxpayer Relief Act of 2012 (H.R. 6, Sec. 407) in January 2013 and survived attempts to cut it in recent 2012 "fiscal cliff" legislation and will be extended for at least one more year.²⁷ The ITC, generally considered more desirable, also will continue and has been extended as is through at least the end of 2016, after which current policy has it dropping to a 10% credit. The Investment Tax Credit (ITC), which currently covers 30% of total costs, over the life the project, is an adequate, albeit more costly replacement for the grant for larger scale TPP projects. It will also likely continue to depress small-scale PV viability in coming years (Linder & De Capua, 2012).

SS 1603 Treasury Grants

Initiated as part of the American Reinvestment and Recovery Act, the 1603 Treasury Program allowed solar and other renewable energy project developers to receive a direct federal grant in

²⁷ The PTC has historically been renewed multiple times, including recent fairly extreme federal budget cuts, suggesting that the credit will survive for short-term foreseeable future.

lieu of the Section 48 Investment Tax Credit. The Treasury Grant was designed help ease the problem of a dearth of financing credit available during the 2008 recession and allowed many projects to move forward without need of a tax equity investor.

The deadline for 1603 grants has passed; eligibility necessitated that entities commence construction on projects by December 31, 2011. The funds will, however, bolster installation figures for several years to come, since many projects that did qualify under this deadline have yet to be completed; applicants need only have spent “5% of costs” by the deadline have until the end of 2016 to complete construction.

AS of March 2013, the program has awarded over \$3.1 billion for projects in California, 3,740 MW of capacity (US Department of the Treasury, 2013). However, the vast majority of that was for utility-scale projects. As demonstrated by Method 2 results, with only 6% of surveyed jurisdictions utilizing 1603, this incentive played a much smaller role in funding public entities own solar projects.

Modified Accelerated Cost Recovery System (MACRS)

The Modified Accelerated Cost Recovery System another federal support that is likely to remain in force unmodified. The MACRS, first established in 1986, is a method of depreciation in which a business’ investments in certain tangible property are recovered, for tax purposes, over a specified time period through annual deductions. Currently, qualifying solar energy equipment is eligible for a cost recovery period of five years.

The allowance for bonus depreciation has since been extended and modified several times since the original enactment. The federal *Economic Stimulus Act of 2008*, included a 50% first-year bonus depreciation provision for eligible renewable-energy systems acquired and placed in service in 2008. Most recently in January 2013, the *American Taxpayer Relief Act of*

2012 extended the placed in service deadline for 50% first-year bonus depreciation by one year, from December 31, 2012 to December 31, 2013 (DSIRE, 2013)

The following incentives are grants and loans, as opposed to rebates or tax-related incentives.

EPA Climate Communities Showcase

Two of the jurisdictions surveyed were part of the limited term grant program Climate Communities Showcase provided by the Environmental Protection Agency. Five California Jurisdictions were among 50 programs selected to pilot programs to reduce greenhouse gas emissions. The Program is not accepting new applications for programs. However, the Showcase is part of EPA's Local Climate and Energy Program which intermittently provides new grants and seed money for local initiatives that relating to addressing climate change, energy efficiency, and renewable energy projects and programs.

Department of Energy (DOE) 1705 Loan Program

A temporary program by the DOE as part of the 2009 Recovery Act (ARRA) funds, offered loan guarantees, up to 80% of the loan, for renewable energy projects.

The Section 1705 Loan Program sunsetted in September 30, 2011. However, the DOE still has the authority to offer loans of the similar Section 1703 Program. Under 1703, the DOE can guarantee innovative clean energy technologies that are typically unable to obtain conventional private financing due to high technology risks. In addition, the technologies must avoid, reduce, or sequester air pollutants or anthropogenic emissions of greenhouse gases. The Section 1703 program is actively reviewing applications but, as of May 2013, there are no open solicitations under the program (U.S. Department of Treasury, 2013).

EECBG

The Energy Efficiency Conservation Block Grants were first initiated with the enactment of the Energy Independence and Security Act of 2007. Funded by the Department of Energy, the intent

of the grants was to assist public entities in implementing energy savings measures including the development, implementation, and installation of onsite solar. EECBG was infused with new funds through the Recovery Act (ARRA funds) of 2009, including \$49.6 million allocated through the California Energy Commission. As of 2013, just over three-quarters of the funds have been committed already, leaving \$12.3 million available for new projects. The remaining funds are earmarked to be spent on “energy planning that reduces greenhouse gas emissions and dependency on fossil fuels” and thus cannot be used for the capital expenditure portion of a solar project (California Energy Commission, May 2013).

Clean Renewable Energy Bonds (CREBs)

First issued in 2005, Clean Renewable Energy Bonds (CREBs) were bonds issued through the US Internal Revenue Service to finance public sector renewable energy projects. The bondholder receives federal tax credits in lieu of a portion of the traditional bond interest, resulting in a lower effective interest rate for the borrower. After March 2010, new legislation also allowed bondholder jurisdictions to receive a direct payment -- a refundable tax credit -- from the Department of Treasury equivalent to and in lieu of the amount of the non-refundable tax credit.

The funds to be allocated through CREBS were expanded in 2008 and again in 2009, for total \$2.4 billion to be available for “New CREBs”. The IRS made 739 bond issues to California jurisdictions totaling \$800 million during the last round of allocations. The last round of applications for reserved allocations ended in 2010. Currently, the IRS has reached its volume cap for CREBs issued and is not accepting application (Internal Revenue Service, 2013). As of May 2013, the IRS has made no announcements for new allocations or raised volume caps for governmental bodies.

Qualified Energy Conservation Bonds (QECBs)

Qualified Energy Conservation Bonds were first issued in 2009 with the enactment of the Energy Improvement and Extension Act of 2008. Similar to CREBs, QECBs are qualified tax credit bonds that can be used to finance public entities energy projects. Unlike CREBs, QECBs allocations are not subject to a U.S. Department of Treasury application process and bond volumes. Instead funds are allocated through the states; California's bond volume cap is \$381 million, up to 30% of which may be allocated for privately owned or operated projects. QECBs are currently still available and application is listed through November of 2013.

California Energy Commission Energy Efficiency Financing

Public jurisdictions can currently apply for low-interest loans from the California Energy Commission (CEC) for energy efficiency projects. Residential and commercial projects and non-profit institutions are not eligible for these funds. Financing has been available in some form through the State's Energy Conservation Assistance Act (ECAA) Program since 1979, and has allocated nearly \$300 million since that time. The CEC is offering 1% loans for renewable energy projects drawn from the ECAA program fund and tax-exempt revenue bonds, and from the State's Renewable Resources Trust Fund. There is no minimum loan amount, but the maximum loan amount per application is \$3 million. As shown in **Figure 32**, the majority (63%) of loans are distributed to cities and counties, with the remainder going to the other public entity types.

Figure 32: Percentage of Loan Funds by Recipient Type

The pie chart illustrates the distribution of loan funds by recipient type.

Source: California Energy Commission, 2012.

Unfortunately, while the program is not ending, the 1% loan funds are oversubscribed as of May 2013. CEC administrators are accepting waitlist applicants but do not expect to be able to provide new loan funds for 10 months or more (Karen Perrin, CPUC, personal communication, May 15, 2013).

K-12 only Bonds

Initiated under the Taxpayer Relief Act of 1997, Qualified Zone Academy Bonds (QZABs) and Qualified School Construction Bonds (QSCBs) are funded by Department of Education but distributed through the states. QZABs may be used for “rehabilitation or repair of school buildings, purchasing equipment, developing course materials, and/or training teachers and other school personnel” while the QSCBs fund new construction of school facilities (California Department of Education, 2013). In some cases, School districts can utilize these bonds to fund solar projects, generally when part of a large capital improvement project and when there is an educational component. The QZABs are low interest loans (under 1% in 2012) and are currently available; California’s 2013 allocation was \$48,715,000.

Solar Market and Funding Post-2012

As **Figure 32** above illustrates, many of funding sources that were utilized by California's jurisdictions to fund their solar projects are concluded, nearly depleted, or less extensive. It is therefore worth considering whether the experiences of jurisdictions over the last six years remains relevant, and whether solar will continue be feasible and provide savings in the years to come.

Both Method 1 and 2 analyses provided some clues. **Figure 33** shows the trend of initiation of solar installations recorded in the CSI database through the first quarter of 2013. As **Figure 33** clearly shows, a spike in the number of projects occurred in late 2009 and 2010, when the majority of the Federal Recovery Act incentives were being distributed. Likewise, 2011 shows much lower number of installations being initiated, which corresponds to incentives depletion by the beginning of that year. Based on these trends, it seems clear that solar projects have depended fairly heavily these funding sources. Notably, however, the number of applications rose in 2011, and the first quarter of 2013 saw a higher number of projects than any other quarter except two. This level of applications was achieved despite most short-term federal incentives being depleted and CSI rebates at their lowest level. This would indicate continued interest and viability by California's jurisdictions to invest solar.

Figure 33: Installations Initiated by Quarter (2006-2012)

This stacked bar chart illustrates the number of projects initiated using direct buy and TPP ownership models over the life of the CSI through the first quarter of 2013.

Method 2 surveys also suggest that solar remains of interest to jurisdictions, even after many of the major funding incentive outlays of the last six years are gone. Nearly half of jurisdictions' staff indicated that their jurisdiction was considering additional solar projects in the near future (Figure 34).

Figure 34: Jurisdictions Considering Solar in the Near Future

Surveyed staff was asked if their jurisdiction would be considering procuring additional solar capacity in the near future.

The end of upfront grants and rebates (from the Treasury Grant ITC and CSI programs respectively) but continuation of PTC and ITC tax credits and low interest loans suggest that Third-Party provider models and hybrid TPP-bonding will play an increased role in the near-term. A recent study by Bloomberg New Energy Finance (Linder, Stefan & De Capua, 2012) on the landscape for US solar financing, supports the theory that TPP structures will play a greater role.

Conclusions

This thesis is intended to shed light on the direction of solar acquisition for California's public entities over the last six years and to provide specific guidance on the benefits and uses of specific financing and ownership options available to those entities. Analysis of the over 1,700 public installations during those years reveals a fast growing market, with over 400 MW installed on public property to serve jurisdictional electricity needs. These installations have been initiated by a variety of jurisdiction types and sizes throughout the state.

In general, jurisdictions indicate that these solar projects are a success: most projects are providing significant money savings, and staff is satisfied with their PVs' performance. However, these jurisdictions did face significant challenges in getting their projects up and running. Not surprisingly, the largest challenges are funding related.

Third-party ownership has become an increasingly available and popular financing method, in part to address funding challenges. Findings regarding overall satisfaction, project completion times, and savings indicate that directly buying installations for a solar projects is a slightly more beneficial for jurisdictions than these TPP alternatives. This conclusion, however, comes with qualifiers relating to financial resources. The first is that most direct buy projects in this dataset were financed in part or whole by outside grant or rebate money, often from federal funds. Jurisdictions certainly benefit from pursuing such outside money sources.

In the absence of receiving outside funding, TPP's are much more likely to meet or exceed the benefits of direct buy projects. Of jurisdictions that utilized direct purchase, nearly three-quarters (74%) used bonds and more than third received grants; resources that greatly contributed their project feasibility and savings. But these resources are not always available to many jurisdictions. With the depletion of several incentive funds on the national and state level, many

funded through the American Recovery and Reinvestment Act of 2009, the capital that has made direct purchases most feasible will become increasingly illusive.

Information garnered from interviews suggest that for many jurisdictions, for the size and kind of solar projects they wanted, upfront cost, credit ratings and other factors made TPP projects a more desirable (or more feasible) option compared to direct purchase. When direct purchase becomes financially unfeasible or desirable, TPP financing and the accompanying tax deduction benefits provide a strong alternative for pursuing a solar project and achieving desired savings. The challenges of TPP projects for the jurisdictions that have utilized these structures over the six-year period seem to be consistent with what national literature on the subject indicates; legal costs and complexity is a major issue, as well as selecting a solar provider than can meet short-term objectives reliably and effectively. While these issues will likely remain challenges for jurisdictions over the coming years, it likely that TPP models will continue play an important role for public solar acquisition in the state in the coming years, as state rebates and other non-tax incentives dwindle (much more than federal tax incentives appear to be likely to), and more solar companies delve into this model. Cooperative arrangements between jurisdictions and use of creative hybrid purchase-TPP models may help ease the challenges associated with the TPP model moving forward.

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APPENDIX 1: SURVEY SAMPLE REPRESENTATIVENESS ASSESSMENT

Method 2: Surveys

Sample comparison to population

The respondents of the survey appear to be fairly representational of all public entities that are engaged in solar acquisition across California, according to type of public entity, service utility area, project sizes, and financing mechanisms used. Conclusions about the representativeness to the larger jurisdictional experience are based on CSI database installations characteristics and literature review of existing research on the public entity solar market. The ways in which the survey sample does deviate from the database of all installations are discussed below.

Like all the installations analyzed in the California Solar Initiative database, the majority of the surveyed jurisdictions are located in PG&E territory, (**Figure 1**). However, PG&E projects are over-represented in the sample; sample respondents from PG&E account for 71% of projects as compared to 58% of total installations in the database. SCE and SDG&E sample are consequently under-represented, by 10% and 8% respectively. While some factors such as siting (due to regional differences in density and approaches to land use decision-making) may be slightly altered by this representation, it is unlikely to result in differences that will skew conclusions about the jurisdictional experience solar considered in this thesis.

Figure 1: Respondents were asked what their jurisdiction's utility provider was.

Note: The CSI database excludes jurisdictions outside investor-owned utility territory or that are their own provider. Respondents that selected 'other' were state agencies with installations in multiple utility territories.

As shown by the Figure 2 map, surveyed jurisdictions are geographically diverse, spanning similar regions and types of development areas as the population of the CSI database overall.

Location of Surveyed Jurisdiction Projects Compared to Population Jurisdiction Projects

Figure 2: This map illustrates the geographic dispersion of solar projects by zip code within the CSI database (blue) and surveyed jurisdictions (green).

Most of the jurisdictions, 64%, took the survey with a solar project that was fully completed and operational, as shown in the **Figure 3**. This generally matches the overall population, in which 70% of installations were completely installed as of January 2013.

Figure 3

As shown in **Figure 4**, most jurisdiction's projects are quite large; over 50% of respondents' solar projects were greater than 400 kW. Projects this size are equivalent to small utility scale projects. By comparison, the average size for all public *installations* in California at the end of 2012 was 248 kW, and the average commercial installation was 135 kW²⁸. Taking into account the project-level units here, it seems that while quite large, these jurisdictions are on par with

²⁸ California Solar Initiative, January 1st 2013.

non-residential projects across the state. They are also probably indicative of the overall solar market trend toward larger scale installations.

Figure 4

Of particular importance this thesis research, is the percent of respondents that utilized a third party provider (TPP) ownership model versus direct buy. As shown in the figures below, 41% of solar projects from respondents were TPP projects, a slightly higher percentage than installations of the population (33% TPP). This result is not surprising considering that respondents were specifically asked to answer with a TPP project in mind if the jurisdiction had engaged in several projects with different financing models utilized²⁹. It is important, however, to recognize, that TPP projects tend to be larger in scale and involve more installations within a single. Since the population data does not connect installations to their larger projects, a truly direct comparison is not possible, and inconsistencies in data may not be clear.

The database data also does not provide a breakdown of types of TPP. However, the survey respondent breakdown between power purchase agreements (PPA's) and leases is consistent with the body of literature, which shows that leases are far less common; and, as consistent with survey responses, most lease agreements are made by school districts.

²⁹ The decision was made to ask specifically about TPP projects because these projects were of particular interest for thesis questions, and thus help ensure that a large enough sample size was collected to make meaningful conclusions about this ownership model.

APPENDIX 2: SURVEY TOOL

Solar Acquisition for Public Entities

****NOTE: This survey was administered through Survey Monkey and utilized skip logic. Thus, not every participant saw every question.*

Thanks for taking part in this solar PV study!

The following survey is part of research project intended to get a better understanding of how public entities in California are obtaining energy for their own facilities' use through solar photovoltaics (PVs). Please read the following Informed Consent to Participate in the Survey:

A research project on best practices in funding solar power acquisition is being conducted by Dana Hoffman in the Department of City and Regional Planning at Cal Poly, San Luis Obispo. The purpose of this survey is to compare experience of public entities in California using different funding structure options including, leasing, power purchase agreements, and direct purchase to access electricity from solar photovoltaics on their property.

- To participate in this study, you will be completing a survey.
- It will take 10 to 15 minutes to complete.
- You are not required to participate in this research and may stop at any time without penalty.
- You may skip any items on the survey you prefer not to answer.
- There are no risks anticipated with this survey.

Your survey responses will be kept in a secure database that will only be viewed by the primary researcher, will be used only to form general conclusions, and no identifying information will be published, in order to protect your privacy. At the end of the survey you will be asked if you would also be willing to participate in a follow-up interview. Interviews could be by telephone or Skype, and would last about 30 to 60 minutes.

Potential benefits associated with the study include an increased awareness and understanding of the funding structures available and the experiences of other public entities in acquiring solar power. The information you provide may be helpful in providing future guidance to your jurisdiction and other jurisdictions in best practices for acquiring solar photovoltaics.

o For questions about the survey or information on survey results, please feel free to contact Dana Hoffman, Masters Candidate at 720-935-6772, dmhoffma@calpoly.edu.

o If you have any concerns regarding the manner in which the study is conducted, you may contact Dr. Steve Davis, Chair of the Cal Poly Human Subjects Committee, at (805) 756-2754, sdavis@calpoly.edu, or Dr. Dean Wendt, Interim Dean of Research, at (805) 756-1508, dwendt@calpoly.edu.

.

If you agree to voluntarily participate in this research project as described, please indicate your agreement by completing the survey. Please print this consent form NOW and retain it for your reference.

THANK YOU FOR YOUR PARTICIPATION!!!

PAGE 2

Q1

1. What is your Name?

Q2

2. What is your work title?

Q3

3. What is the jurisdiction or organization type:

- ☐ School District
- ☐ College or University
- ☐ City Government
- ☐ County Government
- ☐ Special District

- ☐ State Agency
- ☐ Federal Agency
- ☐ Other (please specify)

Q4

4. What is the Jurisdiction's/Organization's Name:

Q5

5. Who is your electricity provider?

- ☐ Pacific Gas & Electric (PG&E)
- ☐ Southern California Edison (SCE)
- ☐ San Diego Gas & Electric (SDG&E)
- ☐ Other (please specify)

PAGE 3

Note:

The study is especially oriented towards comparing THIRD-PARTY FINANCING options, including power purchase agreements and leases, to DIRECT PURCHASE options. If you have participated in a project involving a third-party provider contract, please complete the survey with that project in mind.

A “PROJECT” will include multiple installations at several sites if purchased under the same contract or single financial arrangement.

Q6

6. What is the solar installer (company name) for this project?

Q7

7. What will be the total installed kilowatts (kW) size of the project at completion?

- ☐ <10 kW
- ☐ 10-50 kW
- ☐ 51-200 kW
- ☐ 201-400 kW
- ☐ >400 kW

Q8

8. On what type of facility or location is the installation(s) located? Select the description that best fits for all the installations included in the project.

(Remember, a "project" includes all solar installations under the same contract or single financial arrangement.)

- ☐ High, Middle, or Elementary School Building
- ☐ Ground Mounted
- ☐ Office Building
- ☐ University Building
- ☐ Wastewater Treatment Plant
- ☐ Parking Lot Shading Structure
- ☐ Public Transportation Station
- ☐ Other (please specify)

Q9

9. Are the solar installations part of new buildings being constructed or on existing facilities (check all that apply)?

- ☐ Newly constructed facilities

☐ Existing facilities

☐ Neither, Ground-mounted or other

Other (please specify)

Q10

10. What is the status of the project as of March 2013?

- ☐ Fully operational (all sites completed)
- ☐ Partially operational (some sites completed)
- ☐ Under construction (no sites completed)
- ☐ Still in planning phase
- ☐ Cancelled

PAGE 4

Q11

11. In the box below, please briefly describe why the project was cancelled.

PAGE 5

Q12

12. About how long did it take to get the project completed (from initial planning phase to full operation)?

- ☐ Less than 6 months
- ☐ 6 months to 1 year
- ☐ 1 yr—3 year
- ☐ More than 3 years
- ☐ Don't Know

PAGE 6

Q13

13. About how long is it expected to take to get the project completed (from initial planning phase to full operation)?

- ☐ Less than 6 months
- ☐ 6 months to 1 year
- ☐ 1 yr—3 year
- ☐ More than 3 years
- ☐ Don't know

PAGE 7

Q14

14. Is the project part of a regional or larger institutional cooperative/partnership agreement (e.g. system-wide, or led by a council of governments or some other entity that you are working with?)

- ☐ Yes
- ☐ No

Comments

PAGE 8

Q15

15. What is the lead agency/entity of the cooperative/partnership agreement?

PAGE 9

Q16

16. How important were each of the following elements in prompting your jurisdiction to undertake this project?

	Very Important	Somewhat Important	Unimportant
Environmental benefits	☐ *How important were each of the following elements in prompting your jurisdiction to undertake	☐ Environmental benefits Somewhat Important	☐ Environmental benefits Unimportant

this project?

Environmental benefits

Very Important

Deal provided by installer/contractor	☐ Deal provided by installer/contractor	☐ Deal provided by installer/contractor	☐ Deal provided by installer/contractor
	Very Important	Somewhat Important	Unimportant
Demand of constituents	☐ Demand of constituents	☐ Demand of constituents	☐ Demand of constituents
	Very Important	Somewhat Important	Unimportant
Limited-time incentives or rebates	☐ Limited-time incentives or rebates	☐ Limited-time incentives or rebates	☐ Limited-time incentives or rebates
	Very Important	Somewhat Important	Unimportant
State mandates	☐ State mandates	☐ State mandates	☐ State mandates
	Very Important	Somewhat Important	Unimportant
Meeting your own jurisdictional policy/mandates	☐ Meeting your own jurisdictional policy/mandates	☐ Meeting your own jurisdictional policy/mandates	☐ Meeting your own jurisdictional policy/mandates
	Very Important	Somewhat Important	Unimportant

Participation in a regional or system cooperative effort

☐ Participation in a regional or system cooperative effort Very Important

☐ Participation in a regional or system cooperative effort Somewhat Important

☐ Participation in a regional or system cooperative effort Unimportant

Savings on electricity

☐ Savings on electricity Very Important

☐ Savings on electricity Somewhat Important

☐ Savings on electricity Unimportant

Demonstration project

☐ Demonstration project Very Important

☐ Demonstration project Somewhat Important

☐ Demonstration project Unimportant

Staff "champion" for project

☐ Staff "champion" for project Very Important

☐ Staff "champion" for project Somewhat Important

☐ Staff "champion" for project Unimportant

Other (please specify)

Q17

17. How is the funding of the project structured?

☐ Direct Purchase (installation(s) owned by jurisdiction)

☐ Third Party Provider (e.g. Power Purchase Agreement or Leasing Arrangement)

☐ Other (please specify)

PAGE 10

Q18

*

18. Did the jurisdiction consider other funding structures? Select all that apply.

☐ Don't Know

☐ No, did not seriously consider other funding structures

☐ Yes, power purchase agreement

☐ Yes, lease

☐ Yes, several third-party provider options considered

Other (please specify)

PAGE 11

-

*

19. What kind of third-party provider contract did you utilize?

☐ Lease

☐ Power Purchase Agreement (PPA)

Other (please specify)

PAGE 12

Q20

20. How many years will the installation operate under the contract with the Third-Party Provider?

Years

Q21

21. What is the negotiated electricity rate per kWh for the first year of operation? If the negotiated rate changes over one or more years (eg fixed-escalator) please indicate how the rate will change in the comment box below.

First Year Rate

(\$/kWh):

Rate changes over

time in the

following way:

Q22

22. Will the jurisdiction retain the project renewable energy credits, i.e. RECs?

- ☐ Yes
- ☐ No
- ☐ Don't know

Q23

23. Does the Jurisdiction intend to buy the project installations (during or at end of contract)?

- ☐ Not applicable, no option is included in the contract
- ☐ There is an option and we have already taken it or plan to do so
- ☐ There is an option and it is still under consideration

- ☐ There is an option and we do not want to buy the installation
- ☐ Don't know

PAGE 13

Q24

24. How important were each of the following considerations in selecting Direct Purchase or Third Party providers (eg leasing, or power purchase agreement) for funding the project?

	Very Important	Somewhat Important	Unimportant
☐ *How important			
were each of the			
following considerations			
in selecting Direct			
Purchase or Third Party	☐	☐	☐
Per kW price of		Per kW price of	Per kW price of
electricity	providers (eg leasing, or	electricity Somewhat	electricity Unimportant
	power purchase	Important	
	agreement) for funding		
	the project? Per kW price		
	of electricity Very		
	Important		

Total cost (gross)	☐ Total cost (gross) Very Important	☐ Total cost (gross) Somewhat Important	☐ Total cost (gross) Unimportant
Upfront cost	☐ Upfront cost Very Important	☐ Upfront cost Somewhat Important	☐ Upfront cost Unimportant
Accessing state and federal monetary incentives	☐ Accessing state and federal monetary incentives Very Important	☐ Accessing state and federal monetary incentives Somewhat Important	☐ Accessing state and federal monetary incentives Unimportant
Lower maintenance or operation responsibility for jurisdiction	☐ Lower maintenance or operation responsibility for jurisdiction Very Important	☐ Lower maintenance or operation responsibility for jurisdiction Somewhat Important	☐ Lower maintenance or operation responsibility for jurisdiction Unimportant
Long-term savings	☐ Long-term savings Very Important	☐ Long-term savings Somewhat Important	☐ Long-term savings Unimportant
Legal time/cost to finalize purchase/contract	☐ Legal time/cost to finalize purchase/contract Very Important	☐ Legal time/cost to finalize purchase/contract Somewhat Important	☐ Legal time/cost to finalize purchase/contract Unimportant

Jurisdictional liability	☐ Jurisdictional liability Very Important	☐ Jurisdictional liability Somewhat Important	☐ Jurisdictional liability Unimportant
Ownership of RECs (Renewable Energy Credit)	☐ Ownership of RECs (Renewable Energy Credit) Very Important	☐ Ownership of RECs (Renewable Energy Credit) Somewhat Important	☐ Ownership of RECs (Renewable Energy Credit) Unimportant
Ownership/control over installation	☐ Ownership/control over installation Very Important	☐ Ownership/control over installation Somewhat Important	☐ Ownership/control over installation Unimportant
Solar provider suggested this option	☐ Solar provider suggested this option Very Important	☐ Solar provider suggested this option Somewhat Important	☐ Solar provider suggested this option Unimportant

Other (please specify)

Q25

25. If your jurisdiction were to invest in another solar PV project, what funding structure would you mostly likely use? Please rank from most likely (1) to least likely (4)

Direct Buy

Power Purchase Agreement

Lease

Other

Q26

26. Is your jurisdiction considering acquiring another solar installation in the near future?

- ☐ Yes
- ☐ No
- ☐ Don't know

PAGE 14

Q27

27. Did the jurisdiction use loans or bonds to help cover the cost of the project?

- ☐ Yes
- ☐ No
- ☐ Don't Know

PAGE 15

Q28

28. Please select all the bonds and loans that your jurisdiction utilized to help fund the project (check all that apply) Note: Grants will be addressed separately.

- ☐ California Qualified School Construction Bonds (QSCB)
- ☐ Federal Clean Renewable Energy Bonds (CREBs)?
- ☐ California Energy Commission Energy Efficiency Financing Program Low-Interest Loan

- ☐ Federal Qualified Zone Academy Bonds (QZABs).
- ☐ Federal Qualified Energy Conservation Bonds (QECB)
- ☐ Federal Modified Accelerated Cost-Recovery System (MACRS)
- ☐ Other (please specify)

PAGE 16

Q29

29. Did the jurisdiction receive any grants from the federal or state government or other donor to cover the cost of planning, constructing, operating, or purchasing the power of the project?

- ☐ Yes
- ☐ No
- ☐ Don't Know

PAGE 17

Q30

30. Please select all the grants that were utilized.

- ☐ Department of Energy Energy Efficiency and Conservation Block Grants (EECBG)
- ☐ California Department of General Services New Construction Grant
- ☐ California Department of General Services School Facilities Program Modernization Grant
- ☐ Other (please provide funding source and name of the program):

PAGE 18

Q31

31. Did your jurisdiction or the third-party provider make use of any of the following incentives? (check all that apply)

- ☐ Federal: Energy Investment Tax Credit (ITC)
- ☐ Federal: Treasury Department 30% cash grant
- ☐ Federal: Renewable Energy Reduction Tax Credit (PTC)
- ☐ California Solar Initiative (CSI) Expected Performance-Based Buydown (EPBB)
- ☐ California Solar Initiative (CSI) Performance-Based Incentive (PBI)

- ☐ California General Feed-in Tariff
- ☐ California Property Tax Exclusion for Solar Energy Systems
- ☐ Utility incentive (other than CSI)
- ☐ Local incentive (please specify below)
- ☐ Don't Know
- ☐ Other (please specify)

Q32

32. Did your jurisdiction implement any special taxes or fees that helped cover the costs of the project?

- ☐ Yes
- ☐ No
- ☐ Don't Know

If yes, please describe

Q33

33. Is this the first project your jurisdiction has developed using this funding structure (e.g. direct buy, PPA etc.)?

- ☐ Yes
- ☐ No
- ☐ Don't Know

PAGE 19

Q34

34. Please rate how big an issue each obstacles/challenge was for getting this project underway? (Consider initial planning to start of operation.)

	Very big	Somewhat big	Not very big	Not an issue at all
☐ *Please rate how big an issue each				
Contract negotiations or legal costs	☐ obstacles/challenge was for getting this project underway? (Consider initial planning to start of operation.) Contract	☐ Contract negotiations or legal costs Somewhat big	☐ Contract negotiations or legal costs Not very big	☐ Contract negotiations or legal costs Not an issue at all

	negotiations or legal costs	Very big			
Staff time	☐ Staff time Very big	☐ Staff time Somewhat big	☐ Staff time Not very big	☐ Staff time Not an issue at all	
Lack of information about solar PVs, solar providers, financing options, and/or investors	☐ Lack of information about solar PVs, solar providers, financing options, and/or investors Very big	☐ Lack of information about solar PVs, solar providers, financing options, and/or investors Somewhat big	☐ Lack of information about solar PVs, solar providers, financing options, and/or investors Not very big	☐ Lack of information about solar PVs, solar providers, financing options, and/or investors Not an issue at all	
Public buy-in	☐ Public buy-in Very big	☐ Public buy-in Somewhat big	☐ Public buy-in Not very big	☐ Public buy-in Not an issue at all	
Siting	☐ Siting Very big	☐ Siting Somewhat big	☐ Siting Not very big	☐ Siting Not an issue at all	
Money	☐ Money Very big	☐ Money Somewhat big	☐ Money Not very big	☐ Money Not an issue at all	
Technological issues	☐ Technological issues Very big	☐ Technological issues Somewhat big	☐ Technological issues Not very big	☐ Technological issues Not an issue at all	
Approval from decision-makers	☐ Approval from decision-makers Very big	☐ Approval from decision-makers Somewhat big	☐ Approval from decision-makers Not very big	☐ Approval from decision-makers Not an issue at all	
Other (please specify)	<input type="text"/>				

Q35

35. Over the life of the project, what level of savings do you anticipate will result from the solar project relative to traditional electricity costs?

- ☐ None
- ☐ 1%-10%
- ☐ 11%-30%
- ☐ 31%-40%
- ☐ Over 40% in savings
- ☐ Don't know

Q36

36. Did the jurisdiction put out an Request for Proposals (RFP) or competitive bid for the project?

- ☐ Yes
- ☐ No

If yes, how many proposals were received:

Q37

37. Have there been any problems with the contract or installation(s) operation?

- ☐ Yes
- ☐ No

If yes, please briefly describe the problem.

Q38

38. Taking into consideration all aspects of the solar project, how satisfied are you?

- ☐ Very satisfied
- ☐ Somewhat satisfied
- ☐ Somewhat dissatisfied
- ☐ Very dissatisfied

PAGE 20

Q39

39. Would you be willing to share a copy of the contract agreement for this project? Note: The contract would be used for reference only and its contents will not be shared or reproduced in any way. If you respond yes, you will be contacted directly.

- ☐ No
- ☐ Yes

If yes, provide preferred contact information:

Q40

40. Would you be willing to participate in a follow-up interview (approximately 45 minutes)?

- ☐ Yes
- ☐ No

Q41

41. To expand the base for this research, we are interested in identifying other jurisdictions, with appropriate staff contacts, who have also done a solar project. If you know of any jurisdictions that are doing so, can you share their contract information? Provide as much information about the appropriate contact as you are able.

Contact 1	
Contact 2	
Contact 3	
Contact 4	

Q42

42. Are there any other tips you would like to share with other local jurisdictions that might be considering a solar project. (EG. critical errors, lessons learned, key stakeholders to engage)

PAGE 21

That's it! Thanks for completing the survey.

Your responses will be used to determine the state-of-the-practice for public solar acquisition, and to produce a Guide that will provide public entities throughout California essential information about the best practices for solar acquisition.

For questions about the survey or information on the results or Guide, please feel free to contact Dana Hoffman, Masters Candidate at 720-935-6772, dmhoffma@calpoly.edu.

APPENDIX 3: INTERVIEW STANDARD QUESTIONS

1. Confirm name, title, time they have.
2. Can you tell me a little bit more about the role you played in [jurisdiction]'s solar acquisition?
3. Can tell me a bit more detail about the solar project?
 - How many installations?
 - When did the process begin?
 - When [WAS IT/WILL IT BE] complete?
4. In the survey, you said that XXX and XXX were the most important factors in prompting the project. Can you talk a little bit more about these?
 - →Possible follow-ups: Other common factors rated highly by survey takers: environmental benefits, solar champion, limited- time incentives, jurisdictional mandates.
 - Note: Almost all jurisdictions (60% v. imp. 33% somewhat imp) said meeting jurisdictional policies were very important. Want to dig into what those local policies are.
5. In the survey, you listed XXX and XX as the biggest barriers or challenges to the solar project. Can you talk a bit more about these and any other especially important challenges in any stage of the project?
 - Possible follow-ups→ upfront cost, decision-maker approval, siting, staff time, solar contractors, installation components and upkeep...
6. In the survey, you said that you expected the project would provide [XX%] total savings. Can you tell me a little bit more about the finances of the project? What are those savings calculations based on?
 - What rate were they paying before?
 - How much money in grants, loans, bonds, rebates? Which incentives were most important in the equation?
 - How long before it pays off (is that based on a particular forecast in electricity pricing?)
 - Total cost to jurisdiction?
7. Can you tell me a bit more about why you chose to finance the project through [PPA/LEASE/BONDING]? Would you consider other financing options in the future? Why/why not?
 - What do you see as the biggest advantages, disadvantages of this financing model?
 - Do you have any tips for other jurisdictions considering third-party financing?

- → Possible follow-ups: information, legal costs, staff time, retaining RECs, upfront cost
8. In the survey, you indicate that [jurisdiction] [DID/NT] issue an RFP. Can you talk a little bit more about the process you went through in selecting your solar contractor.
 - Are you satisfied with solar provider?
 9. How did you decide on the solar project size? A specific amount of energy goal? Installation space? Cost/how much they could afford? As big as possible—go big or go home?
 10. Can you tell a little bit how [jurisdiction] made decisions about where you sited the installations? What factors went into that decision? (Ground vs parking lot vs rooftop)
 - Possible follow-ups: cost differences, safety, infrastructure, future land use, shading.
 11. In the survey, you indicated that [jurisdiction] [IS [NOT] considering acquiring more solar in the near future. Why [NOT]?
 - → Possible follow-up: Do diminishing rebates like CSI or tax incentives (like treasury grants) play a role?
 12. Do you have any other tips or thoughts about the solar project you would want to share with other public entities considering acquiring solar PVs?

Possible Additional Questions for PPA

1. What are the most important aspects of the PPA contract with the solar provider? Rates? Escalator? Contract time-period? Liability? Financial backer?
2. In the survey, you indicated that [jurisdiction] [IS/NOT] considering buying back the installations either during the contract period or at the end? Do you know what factors will go into making that decision?
 - a. → Possible follow-ups: When during the contract might this come to a head? After the federal incentives pay-out? Other factors?
 - b. **OR** In the survey, you indicated that [jurisdiction] does not have a buy-out option for installations—was a major issue or not? What factors went into making that decision

Possible Additional Questions for Lease (ie school districts)

1. How did the school district decide to acquire solar?
2. [Solar Installer—either Chevron or SolarCity] seems to have a very specific model for leasing solar with schools. Are you happy with their services? What were the key components of the package they offered were most important?
3. What were biggest challenges for the district in doing this?

Possible Additional Questions for Regional Cooperatives

1. Can you talk a little bit more about the cooperative arrangement between [jurisdiction] and [lead agency].
 - a. What role does lead agency play in the process?
 - b. What other entities are involved in the cooperative?
 - c. What are the benefits of doing this as a cooperative?
 - d. What are the disadvantages of doing this as a cooperative?
2. How much total solar is being acquired through the cooperative?
3. Does [jurisdiction] intend to work with cooperative again for future solar projects?

APPENDIX 4: INTERVIEWEES LIST

Julie Benabente, Energy Officer, City of San Jose

Jason Coughlin, National Renewable Energy Laboratory

Dennis Elliot, Assistant Director, Energy, Utilities, and Sustainability, California Polytechnic State University

Keith Houchen, Director of Buildings, Maintenance, Grounds, & Transportation, Live Oak Unified School District

Benjamin Lucha, Senior Administrative Analyst, City of Palmdale

Amy Reardon, California Solar Initiative Administrator, California Public Utilities Commission

Heather Swan, Project Coordinator, Lancaster Local Power Authority

Ben Peters, Senior Analyst, REC Solar

APPENDIX 5: GEOGRAPHICAL DISTRIBUTION OF SOLAR INSTALLATIONS BY FINANCING STRUCTURE

California Public Entity Solar Projects: Size and Financing (2006-2012)