OWNERSHIP STRUCTURES AND FINANCING OPTIONS FOR SOLAR ENERGY GENERATION IN THE REDWOOD COAST ENERGY AUTHORITY SERVICE AREA

By

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ABSTRACT

OWNERSHIP STRUCTURES AND FINANCING OPTIONS FOR SOLAR ENERGY GENERATION IN HUMBOLDT COUNTY

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Ownership structures and financing sources for photovoltaic (PV) solar arrays have a large effect on the economic feasibility of a project. This thesis examines potential ownership structure and financing combinations for a one-megawatt PV solar array in Humboldt County. The options deemed suitable for the context of the project are discussed qualitatively. A subset of the financing options and ownership structures are modeled using the National Renewable Energy Laboratory's System Advisory Model to gauge their economic viability.

Access to the Investment Tax Credit (ITC) and other tax advantages are the most crucial variables for a competitive solar array. Not all ownership structures can harness the assistance of the ITC; selecting an ownership structure that can is likely to result in the least expensive energy, even with higher cost financing options. Due to sunsetting tax benefits, beginning a project by the end of 2018 gives it an economic advantage from which later projects are not forecasted to benefit.

ACKNOWLEDGEMENTS

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My mothers have always been my greatest support. They taught me that I could do whatever I put my mind to. Going into the energy field was a surprising turn of events but they never wavered.

So much of what we learn in school is from our fellow students. I am delighted that I have been able to learn with and from this cohort of generous, motivated and thoughtful people.

My colleagues at Redwood Coast Energy Authority were the inspiration for this project. I continue to be impressed by their passion and creativity for the cause of protecting our environment. I am so grateful for the opportunity to continue the work with them now.

I have a hard time imagining completing this project without the love and support of my partner, Jeremiah. You make me feel like together we can leave the world a better place than we found it. Thank you.

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

LIST OF APPENDICES

INTRODUCTION

The landscape of the electricity sector in Humboldt County has been upended. In May of 2017, Redwood Coast Energy Authority's (RCEA) Community Choice Energy program took over the procurement of energy for most customers in Humboldt County. With this restructuring, RCEA has pursued an electricity procurement policy with the intention of better representing the values of the community (Redwood Coast Energy Authority, 2016). The key tenets of this policy are renewable energy utilization and local economic development.

While biomass generation has been the staple of renewable energy in Humboldt, RCEA is interested in procuring a variety of local renewable energy types (Schatz Energy Research Center, 2013). In the power provider's founding documents, they expressed particular interest in developing solar energy generation in the local area. RCEA set a goal to procure five megawatts of local solar by 2018 and intends to contract for 15 megawatts of local solar within the first five years of operation (Redwood Coast Energy Authority, 2016).

Unfortunately, the solar resource in Humboldt County is not as strong as other parts of the state (See Figure 1). All else being equal, the cost of electricity will be more expensive than solar power from sunnier regions, so the choice of financing and ownership structures will be particularly important in making solar projects feasible.

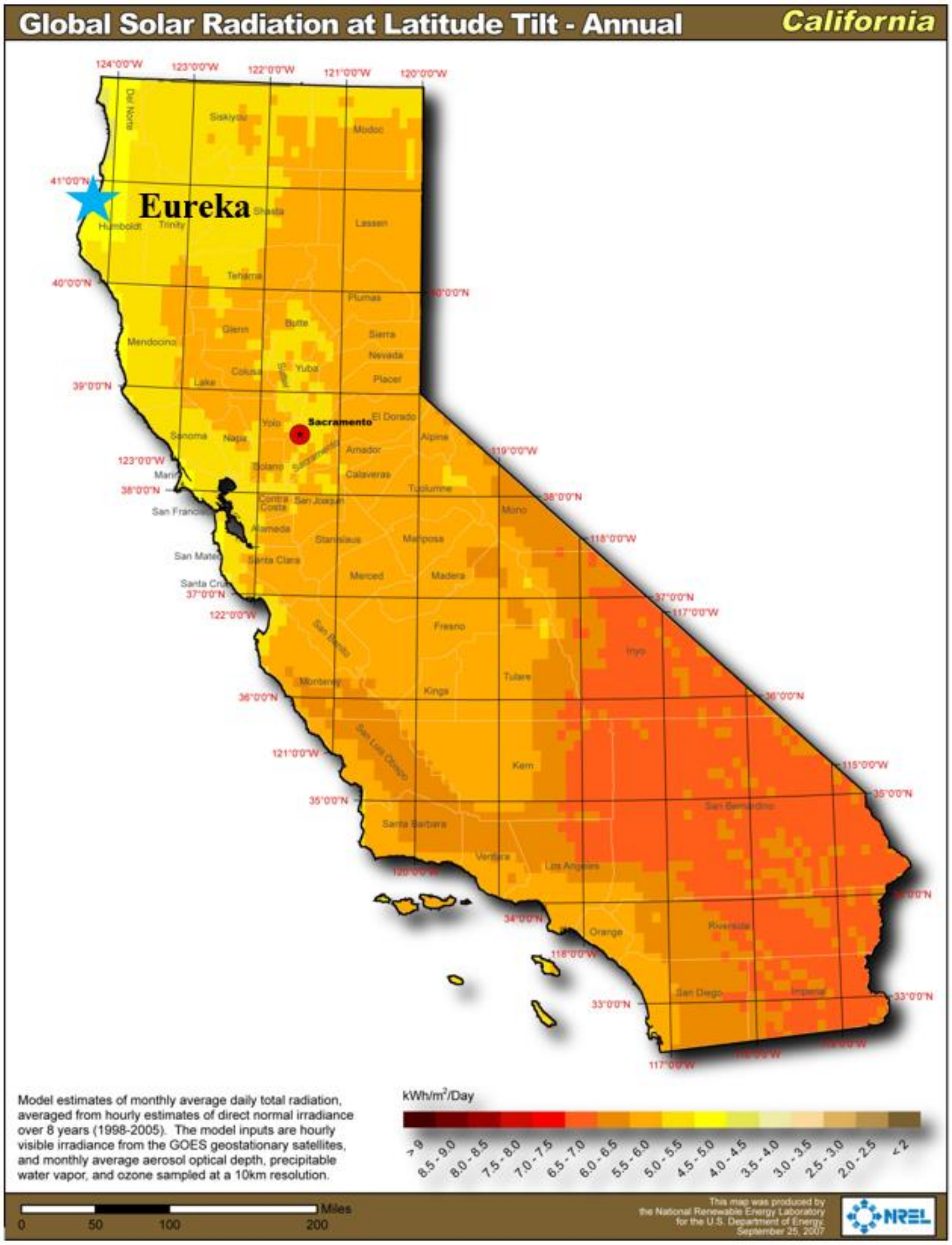

Figure 1. A heat map of the photovoltaic resource in California (NREL, 2017b).

Ownership structures in the solar industry vary due to the values of the community, access to governmental incentives, and to accommodate the needs of the owner. In this thesis I compare tested forms of ownership structures against each other to determine which features of each may offer most economic advantage in the context of Humboldt County. It also explores the different, available financing options.

In this project different ownership structure and finance source combinations for a utility-scale solar array in Humboldt County are compared qualitatively and quantitatively. Some of the discussed ownership structures are modeled using a standardized hypothetical one-megawatt array to properly contrast advantages and disadvantages of the structures to produce economic outputs for comparison. The ownership structures are combined with some of the financing sources discussed in this project to better understand the options for a solar array in Humboldt County. Together those two elements make up the crucial variables of this projects quantitative analysis.

This project does not attempt to provide an exhaustive list of financial and ownership structure options for solar generation. Rather, it focuses on those options that seem to fit RCEA and Humboldt County's context best. This project examines the ownership structures most likely to result in reasonable levelized cost of energy rates for a solar project in Humboldt County.

BACKGROUND

In order to contextualize this project, this section introduces the environmental motivations for building and procuring solar energy, the history and priorities of CCAs in general and RCEA in particular, and the background of Feed in Tariff (FIT) programs. While RCEA does not have a FIT program, other CCAs have such programs, and they are used in this project's quantitative analysis.

Environmental Motivation

The Fifth Assessment from the Intergovernmental Panel on Climate Change (IPCC) reported that anthropogenic climate change is "extremely likely" and that half of the observed increase in global temperature can be linked back to human activity (IPCC, 2014). According to the Environmental Protection Agency, electricity generation accounts for the largest share, 29%, of greenhouse gas emissions from national economic activity (EPA, 2017). There are a number of different strategies for reducing carbon emissions from electricity generation. Reducing the carbon intensity of electricity generation could significantly bolster climate change mitigation efforts.

Redwood Coast Energy Authority

RCEA is a joint powers authority of Humboldt County (Redwood Coast Energy Authority, 2017). A joint powers authority is formed when public agencies come together to create a new public entity to work on a shared cause. This may occur when public agencies would like to address an issue, but they are individually too small to have a dedicated department working on the topic (Cypher and Grinnel, 2006). RCEA was formed by the cities of Arcata, Blue Lake, Eureka, Ferndale, Fortuna, Rio Dell, Trinidad, the County of Humboldt, and the Humboldt Bay Municipal Water District to address energy efficiency, sustainability, security and affordability in the local area (Redwood Coast Energy Authority, 2017). RCEA's original joint powers agreement was formed in 2003 (Redwood Coast Energy Authority, 2015). In 2015, the joint powers agreement was amended to incorporate the community choice aggregation program.

Community Choice Energy

Community Choice Aggregation (CCA) is disrupting the traditional electricity procurement systems in California. While it has been used in other states for some time, the nature and utility of CCAs is transformative in its current usage in California. As the name suggests, CCAs are meant to give communities greater control over the values guiding their power utilities. In California the power of CCAs is being harnessed to decrease the carbon density of the power grid (Lean Energy US, 2017).

CCAs allow communities to take over the task and responsibility of sourcing energy from the utility. While the incumbent utility continues to maintain the physical infrastructure of the local energy system, the CCA procures power and sets generation rates for customers like a municipal utility. In this way, CCAs have elements of investor owned utilities and municipal utilities (See Figure 2). CCAs can capitalize on the existing infrastructure while freeing their constituents from the profit motive of investor owned utilities (Lean Energy US, 2017). CCAs typically represent a given community, but their territory may not always be contiguous as local governing bodies must opt in to the arrangement.

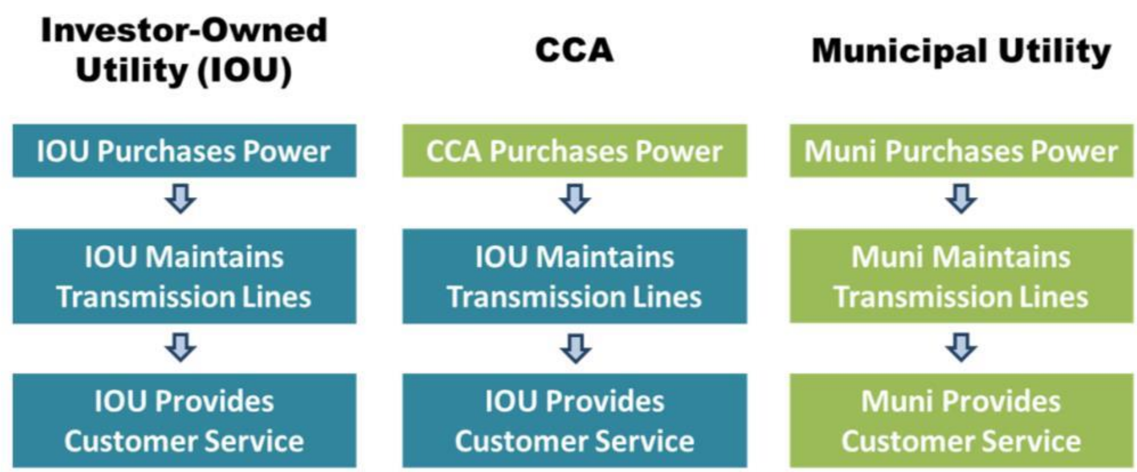

Figure 2. CCAs represent a hybrid of municipal utilities and investor owned utilities. They have components from each model (Mow, 2017).

CCAs are designed to continuously give constituents options. After a community has chosen to enroll in the local CCA, customers are able to opt out of the program at any time and continue sourcing their power from the incumbent utility. In addition, many of the CCAs in California offer different renewable energy mix options with corresponding rates to their customers.

Massachusetts introduced the first CCA enabling legislation in 1997. Since then, seven states in total have sanctioned CCAs (Lean Energy, 2017). The focus of the individual CCAs throughout the country is dependent on the values of the community it serves and the regulatory climate in which it operates.

In 2002 Assembly Bill 117 granted public agencies the ability to form CCAs in California. Since then CCAs have been gathering momentum throughout the state. There are currently eight CCAs operating in California, with an additional 23 communities in the process of launching their own (Lean Energy US, 2017) (See Figure 3). That list now includes Humboldt County, which launched a local CCA in May of 2017. The Joint Powers Authority, Redwood Coast Energy Authority, is the driving force behind the local CCA. Like the other California CCAs, RCEA is invested in reaching higher levels of renewable energy in their power mix than the State's power portfolio. While the existing utility, PG&E, is on track to meet California's renewable portfolio standards, RCEA intends to always exceed PG&E's renewables percentage by at least 5% (Redwood Coast Energy Authority, 2016).

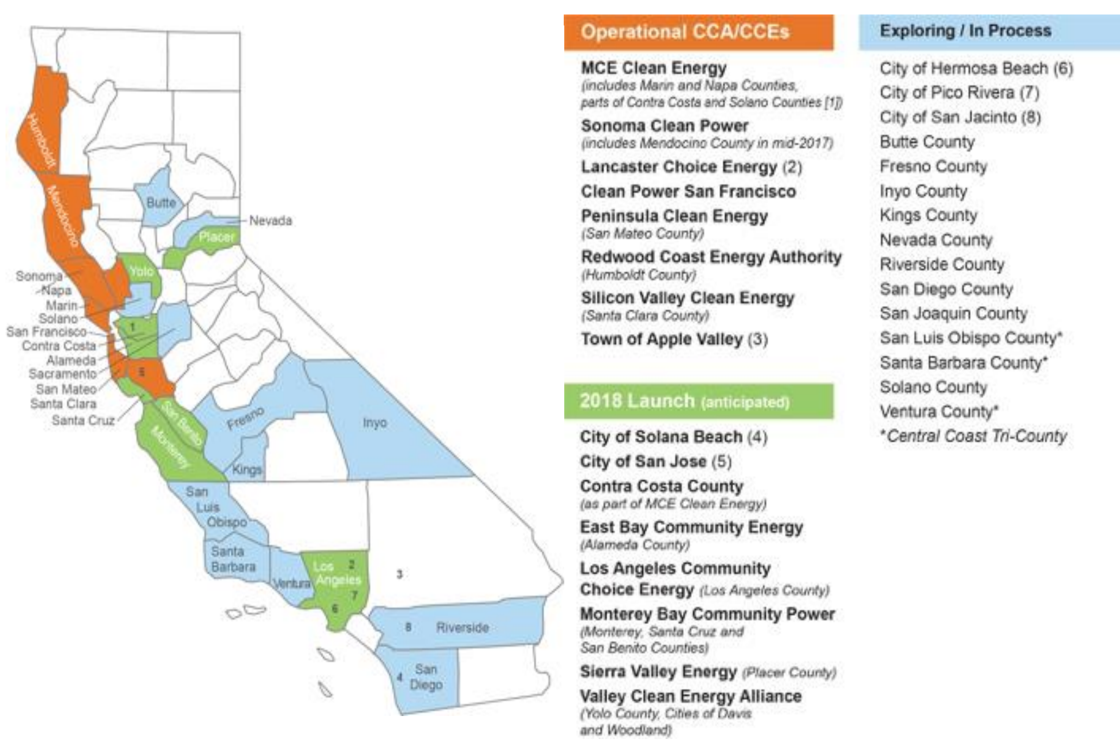

Figure 3. Community Choice Aggregations in California in different launch stages (Lean Energy US, 2017)

In addition to environmental goals, RCEA is committed to supporting local energy sources. Economic concerns are a large motivator for the community and subsequently RCEA (Redwood Coast Energy Authority, 2017). There is a substantial environmentally oriented base in Humboldt County, that would welcome renewable technology even if that meant paying a premium. There are other segments of the community that are more focused on economic development. So, any plan regarding a subject as broad as energy must fully address economic concerns, as well.

Feed-in Tariff

A Feed-in Tariff (FIT) program allows a utility to offer a set rate for energy sales that match their criteria (DiGiorgio, 2017). FIT programs create a market for renewable energy producers that may not otherwise be able join the power generation industry. Small-scale developers can get better access to financing with the guaranteed income through FIT programs. Some programs like Sonoma Clean Power (SCP) offer a base FIT rate and in addition, offer incentives for desirable characteristics like building on previously developed sites or using local developers (Sonoma Clean Power, 2017).

As yet, RCEA does not have a FIT program, although their implementation plan indicates an interest in creating one (Redwood Coast Energy Authority, 2016). Given the small capacity solar PV system that this thesis is analyzing (i.e. one megawatt installed capacity), it is likely that these projects would be subject to RCEA’s FIT. It is therefore worth considering how these models would function within a FIT program.

In accordance with current California law, utilities can use the FIT mechanisms to source renewable energy from producers up to three megawatts in capacity (California Public Utilities Commission, 2017). However, individual utilities may set tighter limits for generation capacity. For example, SCP only allows FIT generation up to one megawatt (Sonoma Clean Power, 2017). RCEA's Implementation Plan indicates an interest in a FIT program for projects less than one-megawatt in capacity (Redwood Coast Energy Authority, 2016). FIT programs offer rates for renewable energy that are generally higher than the market prices. Restrictions for energy generation in FIT programs protect the utility from contracting for too much expensive energy, while still allowing some generators to enjoy the benefits of guaranteed rates (U.S. Energy Information Administration, 2013).

FIT programs can set their own rates for potential producers. While the rates are set, there is often a range depending on the circumstances of the energy generation. For example, SCE has a base rate of 9.5 ¢/kWh but offers up to 13 ¢/kWh for producers that meet certain desirable qualifications (Sonoma Clean Power, 2017). MCE offers FIT rates between 9 and 11.5 ¢/kWh depending on if the energy is intermittent, baseload, or peak (Marin Clean Energy, 2017).

OWNERSHIP STRUCTURES AND FINANCING

This project focuses on two elements of planning a solar array: the ownership structure and the source of financing. These two pieces of the project are some of the most crucial and controllable variables of the financial viability of an array. The ownership structure dictates who is responsible for contributing resources at set times, what benefits the project will gain, who enjoys them and who is liable if the project goes awry. A single organization could potentially play all the roles, but two or more parties are often involved in the construction and operation of a solar array.

There are a number of sources for project-length financing, and the terms of the loans have a significant impact on the economic feasibility of the project. This thesis explores several common and non-traditional sources of financing. The financing estimates are combined with the ownership scenarios to better understand how they function jointly.

Tax Incentives

The defining feature of many of the ownership structures discussed below is their relationship with tax incentives. In fact, many of them would not exist without the promise of tax incentives. There are different aspects of tax credits that inform ownership structures.

Investment Tax Credit

The investment tax credit (ITC) is a federal program to subsidize the solar industry. The tax credit applies to residential systems as well as commercial and utility scale solar generation. It provides a 30% tax credit for projects started by 2019 (See Figure 4). In the current iteration, the credit wanes until 2022 when the residential portion concludes and the commercial and utility scale credit will remain at a constant 10% subsidy (EnergySage, 2016). However, the Congress has extended the ITC multiple times in the past.

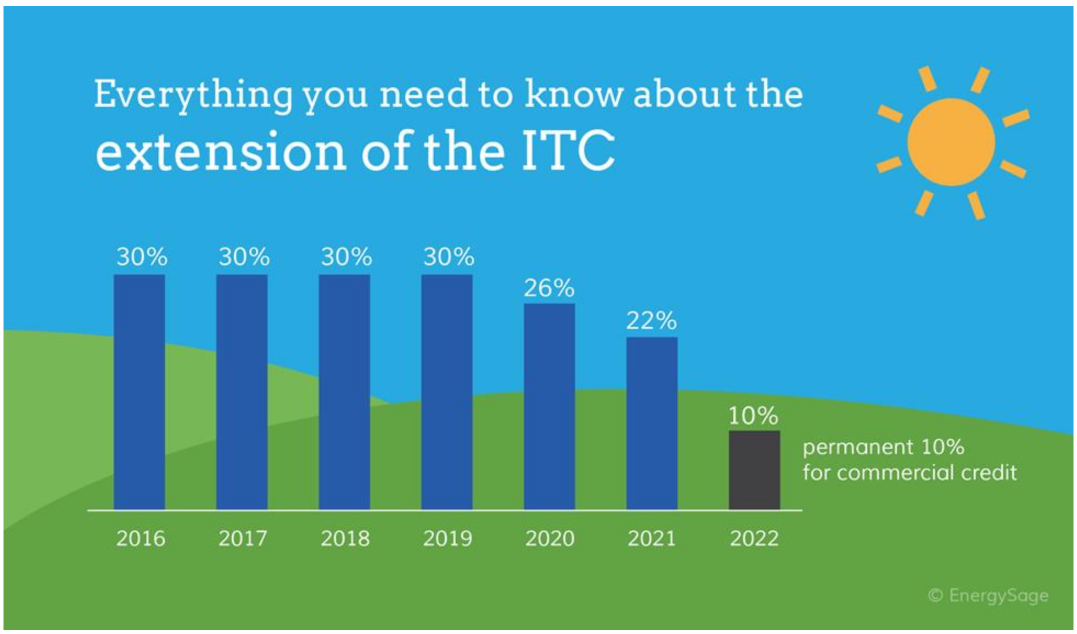

Figure 4. Investment Tax Credit extended schedule through 2022 (EnergySage, 2016).

The 30% tax credit has been a substantial boon to the solar industry. Solar installation has grown by 1600% since the enactment of the ITC in 2006 (Solar Energy Industries Association, 2017). Much of the structuring of solar projects must focus on capturing the ITC to be competitive. However, tax credits create more complications than a cash subsidy. An entity must have a significant amount of tax liability to capture the entire credit. Unlike the Earned Income Tax Credit, the ITC is non-refundable, meaning if an entity has less tax liability than the total potential tax credit the Internal Revenue Service (IRS) will not send a check for the remainder; only an entity with tax liability as large as the project's ITC can harvest the full benefits. On the residential side, this means that low income households do not have equal access to these government subsidies (Davis, 2015). In the commercial and utility scale market, the same dynamic is at play. Governmental bodies, NGOs and smaller private companies cannot access the benefits of a tax incentive on their own. They must forgo the credit or partner with a larger for-profit business that can use a tax shield (Mendelsohn et al., 2012). There are a number of different ways to structure these partnerships. The various partnerships structures are expanded upon in the Tax Equity section.

The tax credit does not have to be used exclusively in the year the project was started. Remaining tax credits may be applied to the previous year or to the next 20 years' taxes (Solar Outreach, 2015). However, spreading the subsidy out over such a long period of time reduces the benefit's usefulness in the short term (Mendelsohn and Kreycik, 2012). This can be a crucial issue since solar projects have large upfront costs and no fuel costs. The economic principle of the time value of money says that money is worth more the sooner it is received (Carther, 2017). Decreasing the high upfront costs or at least spreading them out over the course of the lifetime of the project, through financing, makes a project more economically feasible.

<u>Accelerated and Bonus Depreciation</u>

In addition to the ITC, qualified photovoltaic (PV) projects are eligible for tax depreciation benefits. The Modified Accelerated Cost-Recovery System (MACRS) allows a company building a solar array to depreciate their assets, reducing their taxable income, more quickly (Solar Outreach, 2015). Rather than the project depreciating over its full lifetime, it has a five-year depreciation schedule (See Figure 5). This is a particularly powerful benefit in the solar industry because the lifetime costs of projects are concentrated in the initial stages.

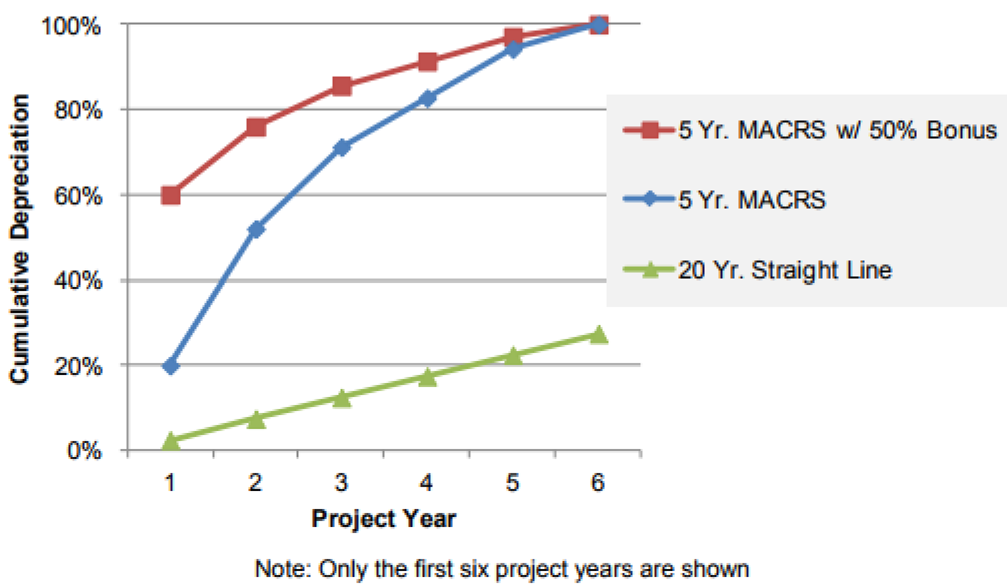

Figure 5. A comparison of MACRS, bonus MACRS and 20-year linear depreciation over the first six years of a project (Mendelsohn and Kreycik, 2012).

In addition to accelerated tax depreciation, the federal government also offers bonus depreciation, which allows controlling companies to depreciate 50% of the assets of the PV project in the first year (Lutton and You, 2017). However, under the current schedule this benefit will begin diminishing after 2017. In 2018 there will still be a bonus depreciation of 40% and in 2019 the rate will be 30%. In 2020 the bonus depreciation benefit expires (Lutton and You, 2017).

Harnessing all three of these tax incentives gives a project the opportunity to write off up to 60% of the total installed cost of the system (Mendelsohn et al, 2012). Considering low prices from other traditional energy sources, these incentives allow solar projects to be competitive in the market.

Fair Market Value

Another crucial tax issue is determining the fair market price for the project. This is hugely important for the ITC because it determines the total from which the 30% tax credit is calculated. If the project is bought and sold, establishing the fair market value is straight forward. However, if the project does not change hands, the Treasury Department will accept three different methods of determining the fair market value. The value must be established by predicting future income from the project, costing out all the system's components or using a similar project as a proxy (Treasury Department, n.d.). The Treasury department does not prefer the future income approach because it allows for a broad range of estimates based on discount rates, inflation and the future economic environment. Generally, the Treasury department prefers that a project establishes its fair market value based on the actual costs of building the project. However, using the costing technique is somewhat open ended, because the developer's markup is an intangible cost that could be exaggerated; a reasonable reported profit is 10% to 20%, and the developer's fee is expected to be between 3% and 20% (Lutton and You, 2017). The third technique, using a similar project as a proxy, could be difficult for an array in Humboldt County because there are not many comparable projects in the area.

The solar developer's incentive is to make the tax basis appear as large as possible so that the tax benefits would be larger. However, inflating the cost of the project is extremely risky because the Treasury Department and the Internal Revenue Service strictly evaluate these tax basis claims (Lutton and You, 2017).

In the case of a tax equity arrangement, where parties join together to reap the benefits of tax incentives that one party would not have had access to alone, there would be multiple players but there would not be a clear sale of the system. Many of the scenarios presented in this thesis would requiring choosing one of the three methods to establish fair market value.

Ownership Structures

There are only a few types of entities that can take advantage of ITC benefits. The simplest arrangement to access the ITC is for one developer with enough tax liability to own and operate the array and reap all the tax incentives. Many parties interested in building solar do not have the tax liability to access the ITC on their own. Solar developers are generally not large enough to be able to reap tax benefits alone (Mendelsohn and Kreycik, 2012). Non-profit organizations, like RCEA, may be motivated by environmental reasons to build solar, but by their non-profit nature they have no tax liability. A non-profit can create a for-profit taxable subsidiary. The subsidiary has the potential to use the tax incentives, but it would still need to be large enough and have enough tax liability to make the project worthwhile (Cotter, 2016). It is unlikely that there would be such an organization in Humboldt County due to the rural nature of the community and the scarcity of tax equity organizations. However, these types of entities could partner with larger organizations to access the tax-based subsidies (Lutton and You, 2017).

This section examines the different ownership structures that would allow an entity with insufficient tax liability to still capitalize on the ITC and other characteristics of these structures (See Table 1).

Table 1. Summary of key elements of the studied ownership structures.

	Single Owner	**Partnership Flip**	**Sale Leaseback**	**Third Party Ownership with Step-in Rights**	**Inverted Lease**	**Commercial**
Equity Owners	Developer	Tax Investor and Developer	Tax Investor and Developer	Tax Investor and Utility	Tax Investor and Developer	Business Owner
Project Level Debt	Yes	Yes	No	No	Yes	Yes
Structure Flexibility	High	Low	High	High	High	High
Transaction Costs	Low	High	Mid	High	High	Low
Frequency of Use	High	Low	Low	Low	Low	High
Access to Muni Bonds or CREBs	No	Yes	Yes	Yes	Yes	No

Tax Equity Structures

The tax equity financial structure was created in response to renewable energy tax credits. Renewable energy developers rarely have enough tax liability to capture the incentives. A tax equity flip is a partnership between at least two organizations in which one has a sizable tax appetite to harvest the ITC. The tax equity investor is often a large bank or an insurance firm (Mendelsohn et al, 2012).

There are multiple ways to structure these agreements. The specifics depend on the actors involved. This section will describe the three most popular tax equity structures: a partnership flip, a sale-leaseback, and an inverted lease. Any of the ownership structures could potentially use a tax equity partnership to capture federal tax incentives.

Tax equity structures are popular because they take advantage of the 30% ITC, but the more complicated they become the higher the transaction costs. Transaction costs in this scenario are often made up of attorney, accountant, and consultant fees. Tax equity structures are relatively new for the solar industry (Lutton and You, 2017). They were created for the wind energy industry. The solar market has benefited from the pioneering work of wind energy finance (Mendelsohn et al, 2012). Still the relative scarcity of experience with tax equity structures increases the transaction costs. High transactions costs incentivize development of bigger projects to dilute the expense.

The first challenge of a tax equity arrangement is finding a willing investor. There is a dearth of investors willing to enter into these arrangements. For this reason they are often able to dictate the terms of the partnership (Lutton and You, 2017). Tax equity investors generally have a strong preference for investments in larger projects. Typical investments are between $75 and $100 million (Lutton and You, 2017). RCEA's current ambition is to source 15 megawatts of local solar in the next five years. Even if all that capacity were financed together, it would be much smaller than a typical tax equity projects. That is not to say that it is not possible to use this financial structure on a smaller scale, but it comes with the aforementioned challenges. Another option is to aggregate the projects with other larger projects making them more attractive to wholesale investors (Cotter, 2016).

Partnership Flip

A partnership flip is a tax equity structure, which involves at least two partners, typically the developer and the tax equity investor. The tax equity investor is the larger organization with a significant tax liability. The partnership is usually structured around achieving a target internal rate of return (IRR) for the equity investor. Sometimes the flips are structured to occur on a certain date rather than after a target IRR is achieved. This structure can either be financed with equity or some combination of equity and debt (Mendelsohn et al, 2012). Both parties contribute to the equity of the project. The developer is responsible for at least 1% of the costs, and each tax equity investor is responsible for at least 5% of the equity, according to tax law (Mendelsohn and Kreycik, 2012). In the beginning, commonly the developer receives all the revenue, or distributable cash, until it has recouped its initial investment. The equity investor receives the lion's share of the tax benefits until the specified date or target IRR is reached. This may be after the five-year period, when the majority of the tax benefits are harvested, or as late as nine years into the project. At that point, the income distribution flips, with the developer getting more of the tax benefits and the equity investor taking in more of the revenue. This structure can include multiple flips to satisfy the requirements of the partners and can include more than two partners (Mendelsohn et al, 2012).

The tax equity partnership may run the course of the project or the tax investor can be bought out. The developer may buy the tax equity investor out of the project once the ITC benefits are captured. The flip is structured in such a way that the tax investor has little stake in the project once the tax benefits are harvested, so the buyout price is minimal (Lutton and You, 2017).

The partnership flip is one of the costlier available tax equity ownership arrangements. The transaction costs of creating the legal partnership can run from $250,000 to $500,000 (Cotter, 2016). Some of these costs are ongoing maintenance requirements.

There is less flexibility in the timing of creating this partnership structure than other tax equity arrangements; the partnership must be in place before the project is developed because the agreed upon rates must be strictly structured to achieve the optimal revenue (Lutton and You, 2017). According to tax law, the developer must invest some capital into the project, which may be prohibitive for a small firm. Also, some of the tax benefits must be used by the developer. If the developer is small enough, it may not be able to take advantage of that benefit (Lutton and You, 2017).

One of the advantages of the partnership structure is that there is more flexibility in the financial performance of the project. If the partnership is based on a target IRR and the project produces less than predicted, the switch date can be pushed back to accommodate the tax investor’s target return (Lutton and You, 2017).

The tax equity flip can be designed using only equity or a combination of equity and debt. In some cases, the tax equity investor provides financing or a third-party lender is brought in. Projects with some debt correlate with lower levelized cost of energy rates (Mendelsohn et al, 2012). However, partnership flips with debt are uncommon. Tax equity investors are less comfortable with the other partners using project level debt because the lender will have first lien on the project. In addition, if the project goes into foreclosure from debt mismanagement the IRS will rescind ITC benefits. If the developer does use project level debt the tax investor will likely increase its required IRR (Lutton and Sussman, 2017). The debt servicing comes out of the revenue stream. So, if there is project debt, paying for debt servicing would affect the developer more than the tax investor in the beginning while the developer is receiving the majority of the revenue.

Sale Leaseback

The sale leaseback structure uses the tax equity investor as the owner of the project for the majority of its functional lifetime. The developer builds the array and sells it to the investor as it is being commissioned. The tax equity investor can then reap the tax benefits. The investor leases the array back to the developer at a presumably lower rate based on the ITC and MACRS benefits (Cotter, 2016). The developer has a power purchase agreement (PPA) with the utility. The majority of its revenue stream comes from the contract rates (Mendelsohn and Kreycik, 2012). The developer would also receive benefits from any renewable energy credits that the project generates. The developer is responsible for paying lease fees to the investor regardless of the actual output and revenue.

This structure has some concrete advantages. The sale leaseback option is simpler than the other tax equity structures, which means fewer transaction costs. The revenue streams are distinct and the tax benefits are not shared. The developer does not have to raise any capital for the project. Also, the structure can be put into place up to 90 days after the project is built (Lutton and You, 2017). However, the developer must produce the lease payments regardless of the actual performance of the array. If the developer intends to buy the array at the end of the lease, the system must be sold at fair market value and that value must be at least 20% of the original value of the project (Lutton and You, 2017).

The sale leaseback mechanism can be used to finance many smaller projects through one partnership. In 2009 Wells Fargo and SunPower Corporation entered into a $100 million sale lease-back arrangement. Rather than building one large solar array, they created multiple smaller, distributed projects like the one-megawatt system for the Western Riverside County Wastewater Authority (PR Newswire, 2009). This example of financially bundled solar arrays is used primarily for commercial projects, but other projects styles, like utility scale projects, could use the same financial structure.

Third-Party Ownership with Step-in Rights

The third-party ownership with step-in rights option is similar to a sale leaseback. However, this structure tends to partner tax equity entities with power providing utilities rather than with developers. Instead of a lease to contract for the energy sales this structure uses a PPA. Written into the contract, the utility retains the right to buy the project at fair market price at will (Cotter, 2016). The purchase of the array could be any time after the initial period when the tax benefits are harnessed. It is important that the agreed price be fair. If it is not the IRS will rescind the tax credits.

Inverted Lease

The Inverted Lease turns the Sale Leaseback structure on its head. The developer retains ownership of the entire project and receives lease payments from the tax investor. The tax investor receives all of the distributable cash and the ITC benefits. The developer may retain ownership of the project after the lease term is up and begin receiving the distributable cash. In this structure, the developer has a portion of the depreciation benefits. That may be useful to the developer if it is large enough to be able to use them, or it may be a net loss for the project if the developer cannot capture the depreciation benefits (Lutton and You, 2017). This is a relatively uncommon way of setting up a solar project and there may not be many tax equity investors willing to partner for it because they access to a smaller percentage of the ITC than other ownership arrangements.

Commercial

Another ownership structure option is for an established commercial business to build an array. The natural first step would be for a business to build enough solar capacity to power their activities on site. If they produced excess energy, a portion of it could be sold back to the utility. The electricity that the commercial entity produces would first cover its energy load. In this scenario, the utility is essentially buying electricity from the commercial producer at their retail energy rate. If the business produces more electricity than it uses, it can sell it back to the utility up to 10% over the base load in territories with net energy metering programs (Patel, 2015). Above that amount, the business would have to meet the requirements for a FIT program if one is available or independently negotiate a PPA with the utility. While RCEA would treat the portion of the solar array that satisfies the on-site energy load and the whole sale portions separately, one large physical system could be constructed at once. That system may be able to achieve a lower cost of due to economies of scale.

If a mutually beneficial contract could be arranged with RCEA, the commercial ownership structure would have certain advantages. A large private business would be able to capture the federal ITC without partnering. Avoiding that set of transaction costs would put the project at a strong competitive advantage. In addition, a private business is in the best position to access grant funding and subsidized financing from the USDA (United States Department of Agriculture, 2017).

Financing Methods

Financing rates are crucial for the economic feasibility of any construction project. According to a National Renewable Energy Laboratory questionnaire, finance concerns are the biggest issue for project development according to 52% of respondents (Mendlesohn and Kreycik, 2012). It can be difficult for solar projects to acquire reasonably priced financing. Even though solar energy projects produce a consistent value, usually with a guaranteed revenue stream, some institutions are only willing to finance the project at high risk rates (Seif, 2014). This, in conjunction with the high target IRRs required by tax equity partners, can make funding a solar project challenging.

The key metric for financing is the interest rate. However, there are other factors which are harder to quantify. Some of the most important qualities for a financial structure are simplicity, standardization, and speed (Mendelsohn et al, 2012). The following sources of funding are evaluated on their interest rate ranges, their ease of procurement and other less tangible qualities (See Table 2).

Table 2. Summary of key elements of the studied financing options.

	Clean Renewable Energy Bonds	**Municipal Bonds**	**Community Solar**	**Project Finance**	**USDA Subsidized Loan**	**All Equity**
Interest Rate	0% - 2%	0.25% - 4.04%	Varies	4% - 6.5%	1%	Not Applicable
Transaction Costs	High	High	High	Low	High	Low
Community Engagement	High	High	High	Low	Low	Low
Uncertainty	High	High	High	Low	High	Low

<u>Clean Renewable Energy Bonds</u>

Clean Renewable Energy Bonds (CREB) are a form of federal tax support for governmental projects. State, tribal, or local governments and energy cooperatives or public power providers can issue CREBs to finance renewable energy projects (Kreycik & Coughlin, 2009).

Theoretically, CREBs allow these organizations to enjoy access to financing without incurring interest payments. The purchaser of the CREB receives a tax credit instead of interest on the loan. However, in some cases the tax credit benefit is not enough to satisfy investors, so an additional interest rate payment is included. Practically, the interest rate for a CREB could be as low as 0% and as high as 2% (Kreycik & Coughlin, 2009). Additional interest rate points may be required if the governmental organization does not meet the required credit rating. Added interest payments may also be included if the demand for CREBs is too low (Kreycik & Coughlin, 2009). In addition, the tax credits are treated as taxable income unlike other tax-exempt bonds (NHA Advisors, 2015). Even with additional interest payments included to sweeten the pot, this still provides a relatively cheap way to secure financing (Kreycik & Coughlin, 2009). The crux of the issue for investors is that the bond issuer’s credit is sufficiently high and that the tax benefits meet or exceed the interest rates that they would be garnering from traditional bonds.

Congress authorizes a limited supply of funds for the CREB program. The capital fund is partitioned into three pools of money available to governments, energy cooperatives, and public power providers (DSIRE, 2015). The CREBs are awarded on a first come first served basis. Ten percent of the CREB funds must be used within the first year that they are allocated, and the remaining must be sunk into the project three years after the funds were awarded. If the project does not comply with those deadlines and does not get an extension, the funding will revert to the communal pot to be reissued to another project (Kreycik & Coughlin, 2009). For some projects, this timeframe can be a restraining factor adding to the complexity of the endeavor. In addition, the application requires some upfront labor and, likely, legal fees. So, for this mechanism high transaction costs and a tight time frame must be weighed against a low interest rate.

Municipal Bonds

A municipality can issue a General Obligation bond or a Certificate of Participation to finance a utility-scale solar array. As a joint powers authority, RCEA can issue bonds (Cypher and Grinnell, 2007). Municipal bonds have the advantage of offering relatively low interest rates. As of June 18, 2017, the yield to maturity (YTM), essentially the interest rate, for a AAA-rated bond is 0.25% to 4.04%. A-rated bonds have a YTM of 0.77% to 3.90% (Edward Jones, 2017). Interest rates are set for the lifetime of the bond. One of the attractive qualities of a municipal bond is that income from interest rates are tax exempt (Investopedia, 2017). While the interest rates are low, investors still consider municipal bonds attractive due to their low risk reputation.

One consideration is that successfully using a municipal bond to raise funds is accompanied by transaction costs. For instance, a bond referendum, when voters approve or disapprove of the issuance of new bonds, would be required. Unfortunately, smaller projects incur proportionately larger transaction costs than their larger counterparts. For projects under 10 million dollars, the median transaction costs are 2.31% of the project’s total cost. This compares with the median transaction cost rate for all bonds of 1.71% (Joffe, 2015).

Municipal bonds may be a better financing option for a project further out in the future. CCAs are still a relatively new phenomenon in California. Marin Clean Energy (MCE), the first CCA in California, is looking forward to using bonds to finance projects, but it is waiting for its credit rating to improve over time (DiGiorgio, 2017). Despite the fact the RCEA has been in existence longer than MCE, the CCA program is significantly younger. It is likely that the RCEA's CCA, like MCE, will need to prove its stability and longevity before earns a favorable credit rating.

Community Solar

Community solar allows energy users to participate in solar generation without putting panels on their homes. Some entity, which could be a developer, NGO or utility, owns the solar array and sells shares to interested customers. In some instances, the members directly own the community solar array (NREL, 2016). Customers may buy actual panels in a solar array or a share of the electricity produced from the array. Leasing or special financing are other possible features. Other options allow customers to pay for their share of the system at time of service like a traditional utility bill.

These programs can be structured in a number of different ways, including virtual net metering directly on the utility bill, in which the customer's bill is reduced by the amount of energy their share of the community solar project produces. The implementation of community solar varies widely, so there is no standard ownership model. The community context, such as the affluence of the area, the aggressiveness of the local environmental goals, and the solar resource, is crucial to the success of the project.

Nearly three-quarters of the residents in the United States are not able to put photovoltaic panels on their homes for various reasons including financial or physical impediments (NREL, 2016). This indicates that there may be a large market for community solar. Community solar is a progressive program as well, in that it can give low-income community members access to savings on energy. Many of the people who are not able to benefit directly from residential solar are low-income renters. Low-income community members may not have the capital or credit to put solar on their roofs or may not own a home. They are, therefore, not able to access the potential financial advantages of residential solar. In addition, community solar may offer better rates than residential solar due to economies of scale. A recent NREL study has found that this ownership structure is growing and forecasts that 32% to 49% of distributed solar in the United States will come from community solar programs by 2020 (NREL, 2016).

Many of the early community solar programs were started by small governments. Small governments and municipal utilities are in a position to recognize public demand for local solar and provide those services (NREL, 2016).

The community solar option does not fit with the other financing methods because, while it would be increasing local renewable generation in Humboldt County, RCEA would not be purchasing the power, the community would be. An interesting feature of community solar programs is that subscribers rarely buy the right to the renewable energy credits (REC) (NREL, 2016). It seems reasonable that RCEA would purchase the RECs from another local organization. In this scenario, the renewable attributes are not technically being double counted, but the satisfaction of environmental responsibility is being enjoyed by the subscribers and by the electricity utility's customers.

Community solar projects vary widely. Reliable financial data to model this scenario were not available. The financing rates that community solar projects can access rely heavily on the structure of the project and the credit worthiness of the institution.

Project Finance

Project finance is a way for a larger company to remove the financing of a particular project from its balance sheet by creating a new company exclusively for the project in question (See Figure 6). Unlike corporate finance, the project only has access to its own cash flow rather than the parent corporation's funding stream or other projects associated with the corporation. This can be advantageous because it limits the liability to the parent company (Pikiel JR, 2015). Project finance appeals to tax equity investors involved in a partnership flip. This strategy reduces the risk to the tax equity partner by moving the project off its balance sheet (Groobey et al, 2010).

Lenders are not always interested to work with project finance structures. It is not in lenders' interest to enter a situation in which they cannot recoup their assets if a project fails. However, they can become more amenable to the project with a PPA in place or some other guaranteed revenue stream. In this case, the utility that is committing to the PPA lends its credibility to the project, which may result in lower interest rates (Groobey et al, 2010). Because it is relatively new utility, it is unclear how much weight a PPA with RCEA would have.

For small utility-scale projects using project finance such as the one this thesis proposes, interest rates are likely to be between 4% and 6.5% (Hubbell et al, 2012).

Specifically, for commercial projects, as opposed to utility scale arrays, project finance interest rates range from 3.25% to 6.85% (Lowder, 2014).

Project financing tends to be used for larger projects. Lenders may not be inclined to finance a project below $50 million and generally prefer projects in the $100 million range (Groobey et al, 2010).

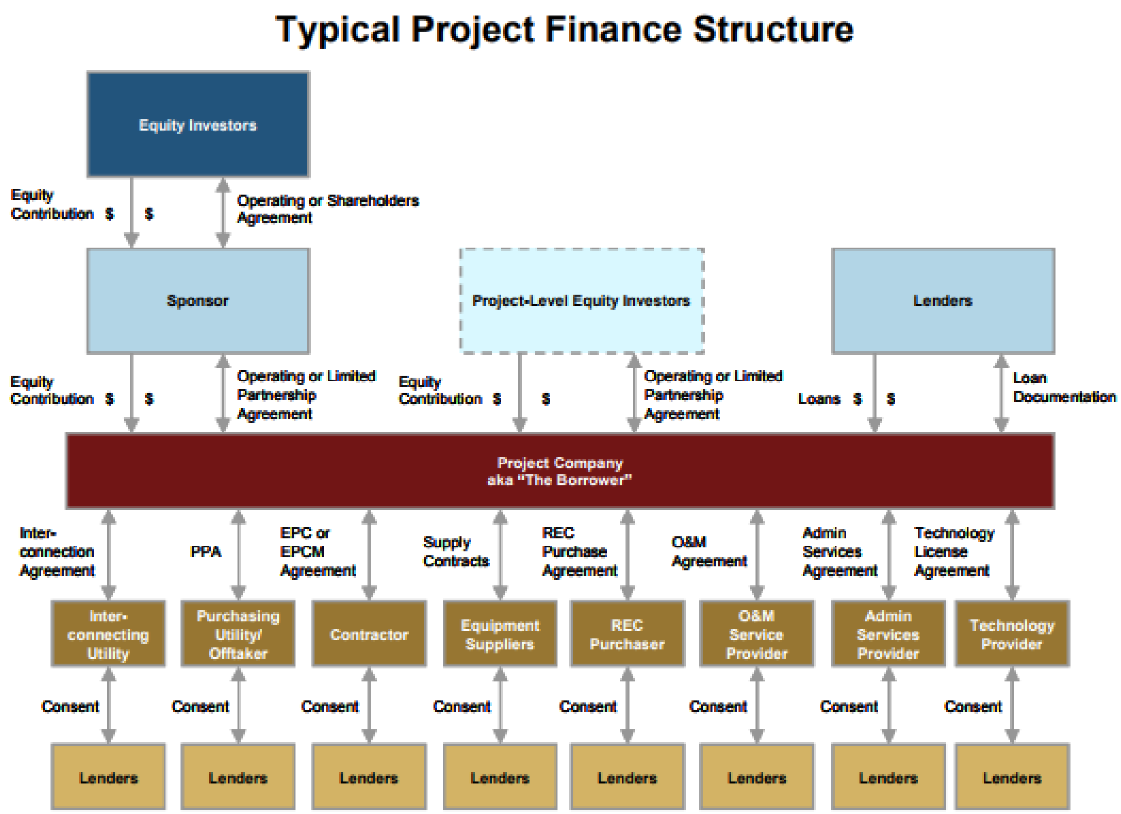

Figure 6. Structure of a typical organization using project finance (Groobey et al, 2010).

Subsidized Loan and Grant Funding

There are a number of grants and subsidized loans for solar projects. A prominent one is the Renewable Energy Systems and Energy Efficiency Improvements Program Grant offered by the United States Department of Agriculture (USDA). This funding is for agricultural businesses or small businesses in cities with a population of 500,000 or less (United States Department of Agriculture, 2017). RCEA could not be the entity to capture the grant because it is not a business. If this mechanism is used in Humboldt County the most likely scenario involves a subsidized loan and/or grants to a local commercial business. There are some scenarios in which the grant could be used with a tax equity flip, but they would require participation by a local business, which would add an additional layer of complexity to the project.

The USDA grant offers up to $50,000 in cash and a subsidized loan up to $25 million. The loan has a 1% interest rate. The grant application deadline for this year was March 31, but the subsidized loan applications are continuously accepted (USDA, 2017). In the quantitative analysis portion of this thesis, the USDA model is based the 1% interest rate loan without the benefit of the $50,000 grant. This type of subsidized loans is expected to produce highly cost competitive projects. According to Mendelsohn et al (2012), PV arrays financed with subsidized loans are expected to financially perform approximately 20% better than projects with conventional financing.

All Equity

The simplest method of financing a project is 100% equity from the owning parties. However, all equity project structures, without any outside debt, tend to result in the highest levelized cost of energy (LCOE) (Mendelsohn et al., 2012). Investors may require higher IRR target rates when there is project level debt, but the end result still tends to be lower LCOEs. To develop a project using 100% equity financing, it is necessary to have the cash on hand at the beginning of the project. Having access to cash through debt allows for a more relaxed timeline and puts less pressure on the PPA prices (Mendelsohn et al., 2012). Most importantly, interest payments are tax deductible, which helps with after-tax cash flow and creates a more competitive project (National Renewable Energy Laboratory, 2017c).

METHODS

Up until this point, this project has explored the qualitative characteristics of ownership structures and financing methods for a megawatt-scale solar array in Humboldt County. This section and the following results section present a quantitative analysis of many of the previously discussed options. This begins with a discussion of the tools that I used to create this analysis.

System Advisor Model

The quantitative analysis portion of this project is based on scenarios created with the System Advisor Model (SAM) program. SAM is a software tool that creates techno-economic models of renewable energy projects. The National Renewable Energy Laboratory (NREL) originally created SAM for internal project estimates. In 2007, NREL released a public version of SAM allowing professionals in the renewable energy industry, as well as researchers, to analyze the potential economic and design concerns of projects. The program is regularly updated to provide a broader and more detailed analysis (National Renewable Energy Laboratory, 2017c). The financial structures on which this thesis relies were added in a recent update.

SAM has tailored models for different renewable energy projects. This thesis exclusively worked with the photovoltaic (PV) models. Within the PV models, SAM provides different ownership and financial models for analysis. SAM offers models tailored to residential, commercial, third party ownership, PPA-single owner, PPA-partnership flip with and without debt, and PPA-sale leaseback projects (National Renewable Energy Laboratory, 2017c).

Fixed Costs

The SAM program uses data inputs to create production and economic forecasts. SAM comes with default data set in the inputs. However, these inputs are from a study based on 100-megawatt solar arrays from Fu et al. (2016). For this project, I replaced the default data with data from the same Fu et al. (2016) study but based on a one-megawatt commercial array (See Table 3). NREL estimated the costs for a one-megawatt array to be \$2.03/installed watt (Fu et al, 2016).

The NREL study, which estimated the cost per installed watt, was published in 2016 but the data were gathered in 2015. The cost of solar is decreasing significantly, so it is important to estimate the likely decline in costs for future projects to improve the accuracy of the model. In order to get an estimate for 2018 fixed costs, I used three different studies with forecasts of fixed PV costs. The first study predicted that the cost per installed watt of solar will drop 10% per year (Farmer and Lafond, 2016). The second study expects costs to drop by 5% per year (Tsuchida et al, 2015). For the third, I used the study's estimate for cost per installed watt in 2018 (International Finance Corporation, 2015). I adjusted NREL's \$2.03/installed watt figure to reflect the two first studies' forecasts for 2018. Then, I averaged the three forecasts together and came to \$1.50/installed watt for a one-megawatt array in the United States (See Table 3).

Table 3. Cost Analysis for the national installed per-watt price for solar PV from different studies in 2018.

Installed $/W (NREL,2015)		**$ 2.03**
Cost Estimate for 2018	Study 1	$1.48
	Study 2	$1.74
	Study 3	$1.27
Average ($/W)		$1.50

In order to better approximate costs in Humboldt County, I used a construction data estimation tool, RSMeans (RSMeans, 2016). It is a tool that some in the construction industry use to estimate timelines and labor materials costs for projects. RSMeans provides region specific multipliers to more accurately model construction costs. The 2016 RSMeans text assesses materials costs in Eureka, CA to be 103.9% of the national average and installation costs to be 118.3% of the national average (RSMeans, 2016). Based on the proportions in SAM's model, 93% of the fixed costs were materials and 7% were installation expenses (See Table 4). I multiplied the materials portion of the fixed costs by the corresponding RSMeans multiplier and gave the installation portion the same treatment. I applied these multipliers to the averaged $1.50/installed watt cost and arrived at $1.57/installed watt for a one-megawatt solar array in Humboldt County in 2018.

Table 4. Fixed cost analysis for a one-megawatt PV array in Humboldt in 2018.

	SAM's Cost Ratio	**RSmeans Multipliers**	**Cost**
Installation Costs	.07	1.18	$0.13
Materials Costs	0.93	1.04	$1.44
Final ($/W)			$1.57

Other Costs

One of the options that SAM provides is to use NREL's PVWatts program for a streamlined technological analysis. This relatively simple design tool is sufficient for the purpose of this analysis. The available solar data for the Humboldt County region are from the Arcata Airport. SAM uses typical meteorological year (TMY) data from the Arcata Airport to estimate resource availability for the rest of the analysis. This analysis uses the TMY3 data set because it is based on more recent data (NREL, 2005). This is a relatively conservative estimate considering that there are areas of Humboldt County with better solar resource than the airport, and it is reasonable that a developer would select land with solar resource in mind.

Many of the costs relating to financing the project are common to all the scenarios. The corporate tax rate for California is 8.84%, and SAM uses a federal income tax rate of 35% (Tax-rates.org, 2017). The real discount rate is set at 5.5% with a 2.5% inflation rate. The annual insurance rate is 0.5% of the total cost of the project. All of the projects, regardless of their financing methods, include additional construction period loans. There is an upfront fee of 1% of the principal, and an assumed 4% annual interest rate.

Incentives

For projects beginning in 2018, the ITC is still set at 30% of the installed cost of the project. According to the current schedule, in 2018 the bonus MACRS will have already begun its decline and must be reduced to a depreciation of 40% of the assets of the project in the first year (Lutton and You, 2017).

The models that employ a tax equity partnership require a cost for acquiring financing including equity closing costs and a 3% development fee. The equity closing costs refer to the transaction costs involved with securing the tax equity partnership. The models that include a variable interest rate also include $450,000 in debt closing costs. NREL based these transactions costs on estimates for a 16.7-megawatt array. Therefore, these default transaction costs may be too large for this project’s one-megawatt array. On the other hand, transaction costs to legally construct a tax equity partnership appear to be substantial regardless of the size of the array (Mendelsohn et al, 2012). So, these same transaction costs will be applied to the significantly smaller array, but a sensitivity analysis will be conducted on this variable to better understand the effect it has on the economic outcomes of the project.

A hypothetical one-megawatt array was selected because scheduling with the California Independent System Operator (CAISO) begins at that capacity. Scheduling with CAISO incurs a flat initial fee and additional fees based on capacity size. The one-megawatt size, or slightly below that capacity, avoids those costs and allows projects to be more financially feasible (California Independent System Operator, n.d.).

SAM Parameter Assumptions

SAM includes system design options, such as module type, orientation and system losses, to more accurately describe the functionality of the solar array and produce more realistic production outputs. While it is important that the generation estimates be reasonable for an array in Humboldt County, this analysis is more focused on the effect that the ownership and financial structures will have on the economic outcomes. For that reason, all the various scenarios will use SAM's standard system design parameters.

SAM Ownership Models

NREL's SAM program provides nine ownership models from which to build. Of those nine, I selected single owner, partnership flip with and without debt, and sale leaseback as models for this analysis.

Single Owner

The single owner model is the simplest ownership structure. SAM uses a project finance model to demonstrate single party ownership. The parent company creates a project company to manage the solar array (See Figure 7). The single owner may or may not have the advantage of being able to fully capture tax benefits. All the tax benefits and distributable cash go back to the parent company (Mendelsohn et al., 2012). The SAM model assumes a target IRR of 11% to be reached in 20 years, the lifetime of the project (National Renewable Energy Laboratory, 2017c). This model includes a $450,000 fee for closing costs and an upfront fee of 2.75% of the total debt. Unlike some of the other structures, this model does not have a set cost for acquiring financing because it does not employ a partnership flip.

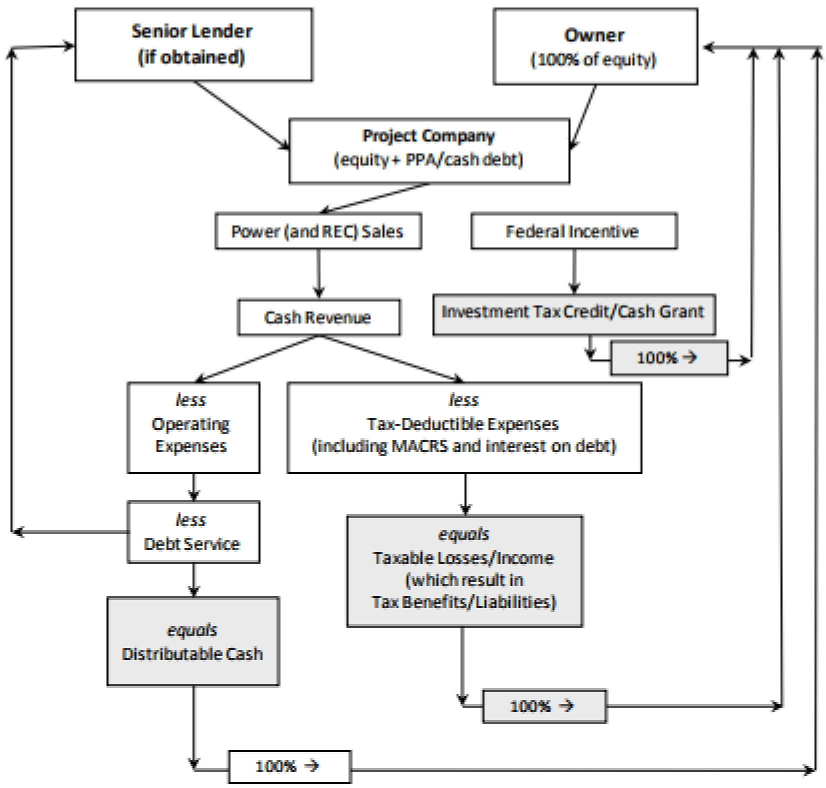

Figure 7. Flow chart for benefits and responsibilities in a Single Owner project over its lifetime (Mendelsohn et al, 2012).

This structure was included to represent a scenario in which RCEA decided to own the project despite not being able to use ITC benefits. It is unlikely that the organization would choose this structure, because there are other options that could produce energy more cheaply, unless it were the only way to access a financing source or grant funds (R. Engel, personal communication, September 15, 2017).

Partnership Flip Structures

A tax equity partnership flip can be structured in many ways. The SAM model differentiates partnership flips in which the project uses outside debt and projects that are fully internally financed.

All Equity

A partnership flip with an All Equity model assumes a target IRR of 9% to be reached in nine years. This model has lower target IRR because the tax equity partner would not have to compete with a lender for assets in case the project founders. The target IRR is the tax investor's inducement to partner with the developer, therefore creating the appropriate returns in a timely manner is crucial. These assumptions are based on NREL's research into the solar industry's use of financing structures (Mendelsohn et al, 2012).

Figure 8 shows the partnership flip structure for an All Equity arrangement. The figure indicates the percentages of the revenue that each partner receives before the flip as the first number in the output boxes. The second number is what they receive after the scheduled flip. The tax equity partner invests slightly more of the equity and receives almost all the tax benefits initially. The developer receives all the "distributable cash"; i.e. the revenue from the PPA minus the operating costs. After the flip, the developer receives a little more of the tax benefits, but still the minority of the payout. At that point, the tax investor gets all of the distributable cash. In the final stage, the developer takes back a small percentage of the distributable cash. This model is simply an example of one of the ways that partnership flips can be structured. The All Equity scenario includes

$300,000 for the equity closing costs but does not include any debt closing costs like the financed options.

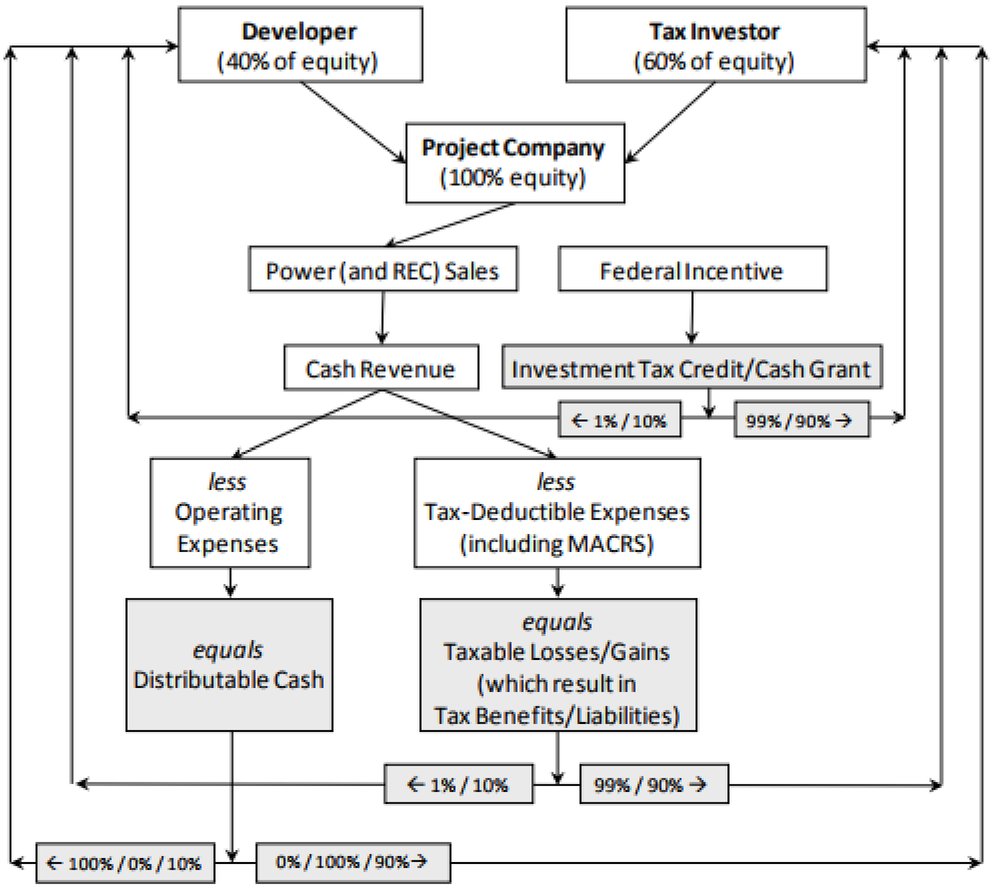

Figure 8. Flow chart for benefits and responsibilities in a Partnership Flip project with all equity over its lifetime (Mendelsohn et al., 2012).

Leveraged. The Leveraged Partnership Flip is structured largely the same as the All Equity option. However, the tax investor contributes nearly all the equity. In this option, the debt-to-equity ratio is based on a 1.3 debt-service coverage ratio (DSCR). This ratio is designed so that the project always has enough cash on hand for debt serving and operations and maintenance. The target IRR for the leveraged flip is slightly higher, at 11%, to be reached in nine years (National Renewable Energy Laboratory, 2017c). The tax investor requires a higher target IRR because the lender has first rights to the assets of the project should anything go wrong (Mendelsohn et al., 2012).

The distributable cash is the revenue from the PPA minus operating expenses and debt serving (See Figure 9). Unlike the All Equity model, the developer starts with a nominal share of the distributable cash and then starts taking in the majority of it when the target IRR is reached. Likewise, almost all the tax benefits go to the tax investor until the flip, when the percentages essentially swap. This model includes both transaction costs: $300,000 for equity closing costs and $450,000 for debt closing costs (National Renewable Energy Laboratory, 2017c).

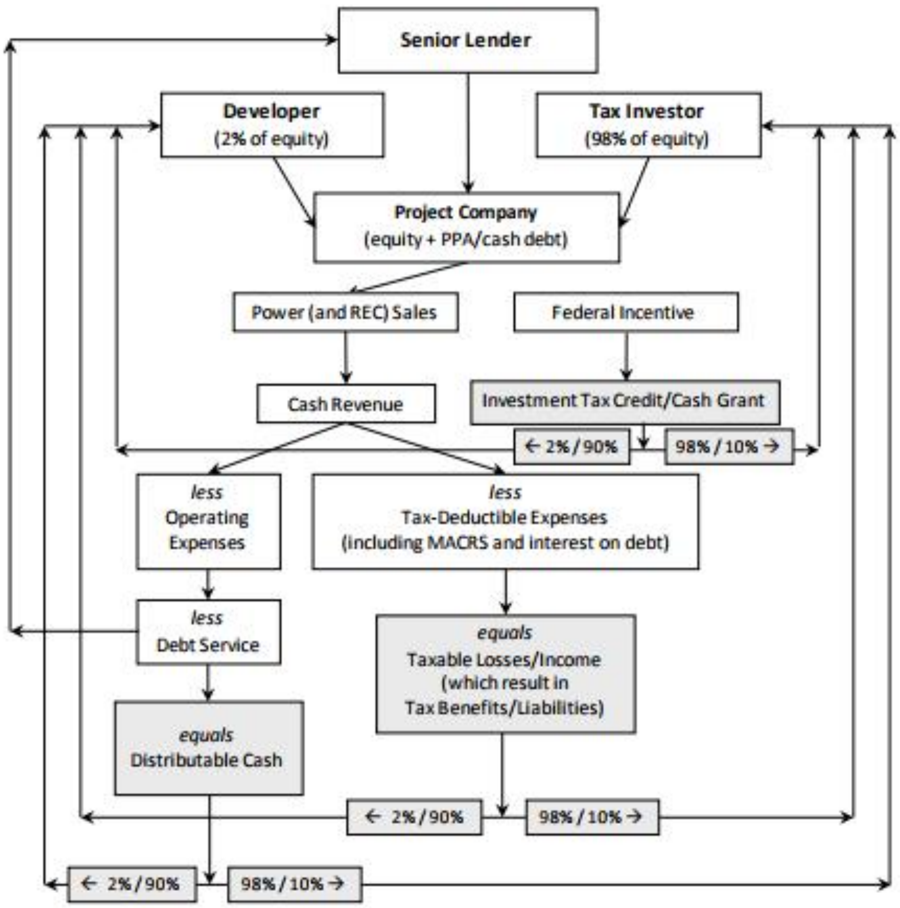

Figure 9. Flow chart for benefits and responsibilities in a Partnership Flip project with debt over its lifetime (Mendelsohn et al, 2012).

Sale Leaseback

In a Sale Leaseback, the revenue streams are fully separate. The tax investor takes in all the tax benefits. The developer receives the distributable cash and pays the lease (See Figure 10). In this model, the two actors are less financially connected, but the tax equity investor still has a 9% IRR target for 20 years. However, both parties are invested in the success of the project; the lease payments are designed so that there will always be enough cash on hand for operations and maintenance and debt servicing (Mendelsohn et al, 2012). This model includes $300,000 for the cost of acquiring financing but no debt closing costs. SAM's Sale Leaseback model does not include the ability specify financing rates. It assumes that the tax investor buys the entire project and then begins leasing it back to the developer. However, it is possible for the tax equity investor to finance the cost of the project. Including project spanning debt could improve the LCOE, like in other ownership models, by spreading the upfront costs over the lifetime of the project. There is debt for the construction period, like the other models, but this is calculated as an all equity scenario. Due to that constraint, there is only one, all equity, set of outputs for this model.

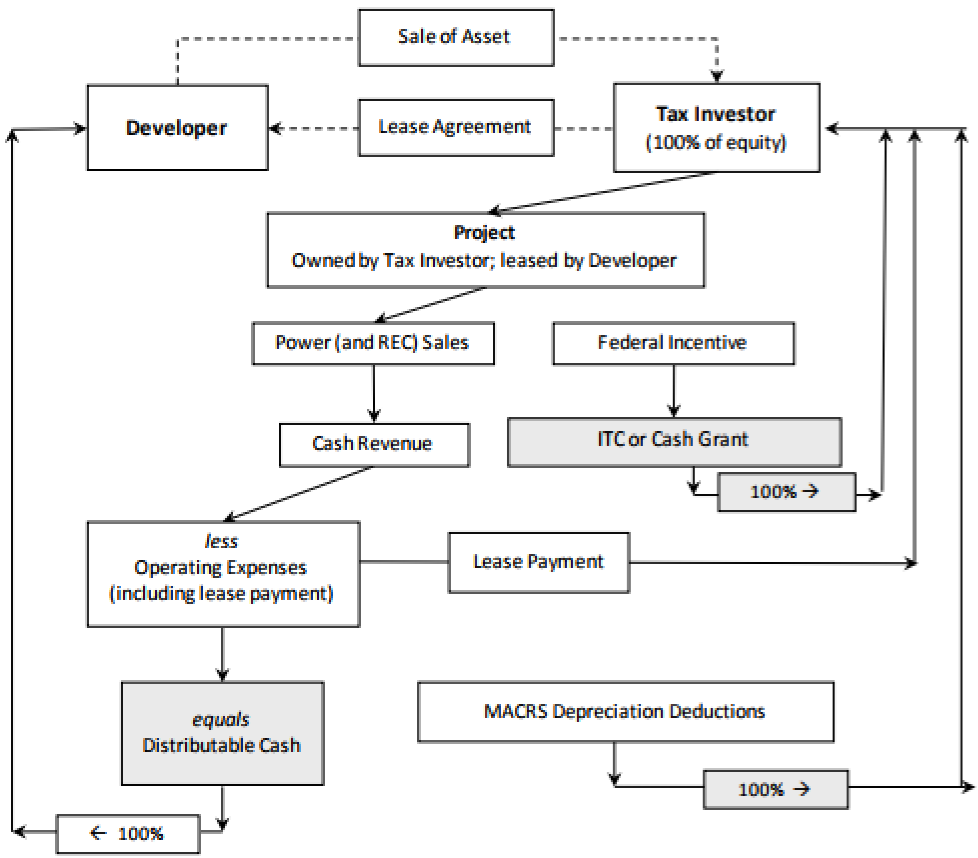

Figure 10. Flow chart for benefits and responsibilities in a Sale Leaseback project over its lifetime (Mendelsohn et al., 2012).

Commercial

SAM has a Commercial model; however, the specifics of this model are outside of the scope of this project. The Commercial model requires detailed information about a business' electrical load. In order to approximate the commercial option, I used the Single Ownership model and included the ITC and depreciation benefits. This configuration will not be as accurate as using the Commercial model, but without a specific business in mind, the inputs would be purely guesswork. The results from this project's Commercial model will likely be higher than the reality of a commercial project because this model does not account for retail priced energy savings.

This project imagines a scenario in which a portion of the on-site generation goes towards the company's operating load, and a portion is sold to RCEA. The company would have the advantage of reducing their cost of energy and potentially making a profit from the sale of excess energy. However, this dual-purpose generation is too complicated for this analysis to model. So, the Commercial model will proceed as if it only includes the capacity destined to be sold to RCEA.

Interest Rates

This analysis treats financing options and their key characteristics, like interest rate, as if they were independent variables. In reality, the type of ownership structure used for a project would have a significant effect on the terms of the available financing. There are a number of variables that inform the interest rate that a given project can secure. To address that issue high and low interest scenarios were included for financing options over a range of interest rates (See Table 5). The terms and interest rates included in this project reflect the industry standard for average projects. However, some unusual ownership structures may require interest rates and terms above the modeled rates to compensate financiers for greater risk.

Table 5. Definitions for high and low interest rates for financing options with established ranges (Kreycik & Coughlin, 2009; Edward Jones, n.d.; Hubbell et al., 2012; Lowder, 2014; USDA, 2017; Mendelsohn et al., 2012).

Financing Method	Low	High
CREB	0%	2%
Municipal Bond	0.25%	4.04%
Project Finance	4%	6.50%
Project Finance (Commercial)	3.25%	6.85%

SAM Output Metrics

Given a complete set of input data, SAM produces a number of performance metrics about an array's energy generation over the lifetime of the project. Using those estimations SAM is able to approximate values for the respective financial metrics. SAM provides the levelized cost of energy (LCOE) and subsequent PPA rate. Both of these metrics are given in nominal and real prices. I have chosen to use real rates for the LCOE and PPA metrics to compare the different project structures. The real prices reflect inflation and give a better sense of costs over the life of long-term projects.

Sensitivity Analysis

The SAM program provides a parametric function for the user to input multiple values into the model and view the results in the form of different metrics. This creates an opportunity to run multiple sensitivity analyses to determine how project economics vary as key inputs change. This function allows the user to better understand the relationship of inputs to outputs.

<u>Transaction Costs</u>

Since transaction costs are unknown, I have included a sensitivity analysis of that element of the fixed costs. While transaction costs are not directly proportional to the size of the project, it is reasonable to hypothesize that a significantly smaller project would have smaller fees associated with creating the legal structure of a tax equity partnership and securing financing. So, this analysis seeks to understand what effect differing transaction costs would have on the LCOE of the project. To understand the relationship between the transaction costs and the LCOE, I ran the model with the transaction costs at 10% increments from 50% to 120% of the original figures. SAM's standard values include $300,000 for the default equity closing costs associated with creating a tax equity partnership, and $450,000 in debt closing costs. All the four ownership structures considered in this analysis involve debt closing costs. Only the Partnership Flip and Sale Leaseback structures have equity closing costs that come from setting up a tax equity partnership.

It is highly likely that transaction costs for acquiring financing would vary across the different financing methods. It is difficult to estimate concrete figures for the specific scenarios. It is possible that the transaction costs could be larger than the baseline figures compiled by NREL due to the rural nature of Humboldt County. However, considering how much smaller this project is than projects that these figures are based on, it seems unlikely that transaction costs would increase past NREL's estimations. For those reasons, I included estimates for transaction costs that are higher than the original estimates but only up to 20% higher.

The All Equity scenario does not require any transaction costs for acquiring financing. The Single Owner model and Commercial model do not use a tax equity partnership, which means that they also do not incur transaction costs, and those scenario combinations are not included in this analysis.

Feed-in Tariff

While FIT programs are losing popularity in the energy procurement industry, RCEA indicated an interest in exploring the possibility of creating such a program in their founding documents (Warren, 2016; RCEA, 2016). To address that original interest, this project will examine the feasibility of the SAM generated projects entering into a FIT structure. The PPA rates, generated for each project scenario by SAM, will be compared to SCP's existing FIT program. SCP's FIT program includes a base rate and additions for desirable characteristics, like building on a previously used site or using local labor. These rate increases will be considered in the analysis.

Location

Another key consideration for the economic viability of a solar array is location. While the scope of this project encompassed Humboldt County and zeroed in on the Arcata/Eureka Airport for weather data, it is reasonable to consider the possibility of other, nearby locations. With that in mind, the Crescent City Airport and Redding Airport were selected to get a sense for the economic viability of a similar project in nearby counties. It is approximately 150 miles from the Arcata Airport to the Redding Airport and 70 miles to the Crescent City Airport (GoogleMaps, 2017). The LCOE values for similar projects in those two locations were calculated to compare to rates in Humboldt County.

To generate a more accurate estimate, I used RSmeans to estimate the initial costs for a project in Redding. I used the initial cost estimate, that was previously calculated, and substituted the materials and installation multipliers for Redding. With those modifications the cost per installed watt in Redding, $1.69, is slightly higher than the cost per installed watt for Eureka, $1.75. RSmeans does not have cost multipliers for Crescent City. For the purpose of this analysis, the cost of materials and installation in Crescent City is assumed to be the same as in Eureka. This is a generous assumption for Crescent City because that area is more remote than Eureka and would likely have higher costs for both installation and materials.

Time of Construction

While RCEA has expressed an interest in procuring local solar energy by 2018, there is a real possibility that the project will not start as planned. Even if the initial five megawatts of local solar are begun by 2018, RCEA has a mandate to continue expanding local solar production in the near term (Redwood Coast Energy Authority, 2016). So, this analysis included a comparison of the same projects starting in different years. If the construction phase is pushed back to 2020, the ITC benefits will decrease to 26% of the cost of the project. Then in 2021, the ITC benefits will diminish to 22%. To address this, the LCOE was determined for the same project in 2020 and 2021.

To get a more accurate estimate, the fixed costs were also adjusted to the forecast of the corresponding year. The same process was used to estimate the fixed costs for

2020 and 2021. However, one of the three forecasts used for the original calculation only extends to 2019. This estimate is, therefore, an average of two forecasts rather than three (See Tables 6,7, 8, & 9). The forecast that did not include 2020 and 2021 was the lowest estimate of the three. So, the fixed cost estimates for 2020 and 2021 are more expensive than the 2018 estimate on which the majority of this project's analysis is based. These estimates are applicable to future projects in addition to near-term projects that are postponed.

Table 6. The analysis for the fixed cost component using historic costs adjusted by future predictions for 2020.

Installed $/W (NREL, 2015)		$2.03
Cost estimate for 2020 ($/W)	Study 1	$1.20
	Study 2	$1.57
Average ($/W)		$1.38

In Table 6, the generic fixed costs for the United States in 2020 are established. Then, in Table 7 the 2020 fixed costs are adjusted for Humboldt County prices.

Table 7. Fixed costs for 2020 adjusted for Humboldt County prices.

	SAM's Cost Ratio	RSmeans Multipliers	Cost
Installation Costs	0.07	1.18	$0.12
Materials Costs	0.93	1.04	$1.33
Final ($/W)			$1.45

Table 8. The analysis for the fixed cost component using historic costs adjusted by future predictions for 2021.

Installed $/W (NREL 2015)		$2.03
Cost estimate for 2021 ($/W)	Study 1	$1.08
	Study 2	$1.49
Average ($/W)		$1.29

Table 8 demonstrates the methods for arriving at national generic fixed cost rate for 2021. In Table 9 the generic fixed costs are modified for the economic context of Humboldt County.

Table 9. Fixed costs for 2021 adjusted for Humboldt County prices.

	SAM's Cost Ratio	RSmeans Multipliers	Cost
Installation Costs	0.07	1.18	$0.11
Materials Costs	0.93	1.04	$1.24
Final ($/W)			$1.35

<u>Target Internal Rate of Return Variation</u>

The estimates for the target IRRs of the tax equity partner, or the owner in the case of the Single Owner model and Commercial model, come from NREL data (Mendelsohn et al., 2012). That information, in turn, was gathered from industry insiders. It is reasonable that there is some range in target IRR rates that these large entities require. Another sensitivity test was applied to the target IRR rate to determine what effect variance in that variable would have on the LCOE. To those ends, the LCOE was calculated using a target IRR plus and minus one percentage point from the original data. The spread was kept relatively tight because the tax equity partners have a significant amount of leverage in negotiating the partnership agreement, and it is unlikely that they would allow the target IRR to deviate much from their ideal. The different ownership models include base target IRRs specific to their circumstances. The subsequent sensitivity analysis will test a range of target IRRs based on the original target IRR rather than a generic spread of rates.

Grant Funding

The original baseline modeling for the USDA subsidized loan financing scenario included the 1% interest rate but not the $50,000 grant offered through the same program. This grant was not included in the models originally because the two benefits are not always awarded to the same project. However, it is possible for the same project to receive both. So, included in the results of this project will be calculation of the LCOE for the USDA Subsidized Loan financing options that includes the $50,000 grant. This grant money would be applied to the fixed costs of the project. To achieve that decrease in the fixed costs, the installed cost per watt was reduced from $1.5700/watt to $1.5284/watt. This produced a difference of $49,920.25. While the change in the installed cost per watt does not result in a perfect representation of the USDA grant funding, the precision is close enough to indicate the effect of the treatment.

ITC vs. Low Interest Rate

One of the key concerns for considering building a solar array, is the reasonable possibility that one project may not be able to capture the ITC and low interest rate at the same time. So, the question is which factor has more bearing on the economic viability of the project? To answer that question, I generated nine data points for the LCOE, using interest rates between 0% and 8%, for the Single Owner, Commercial, and Partnership Flip ownership models. The Single Owner model represents a project without the ITC, and the Commercial and Partnership Flip models represent projects with ITC benefits. That data were plotted to create three lines for comparison.

RESULTS

The results section begins with a presentation of the calculated LCOE values from all the ownership structures and financing options modeled in this analysis. This information is followed by the results of the sensitivity analyses described above.

Overview

The analysis of the results from the SAM modeling program began with a simple comparison of the LCOE and PPA outputs to rank the various ownership structure/financial model scenarios. The baseline models produced a wide range of LCOE and PPA outputs. The LCOE results varied from ¢9.36/kWh to ¢17.26/kWh. The Partnership Flip Ownership Structure produced scenarios with the two cheapest LCOEs (See Table 10). In general, the Partnership Flip Structure performed the best; its average LCOE, across the eight financing options, was ¢11.03/kWh, slightly cheaper than the average for the Commercial model, ¢11.11/kWh (See Table 11 & 12). The Partnership Flip and Commercial Structures were close contenders, dominating the cheapest half of the results between the two of them. Unsurprisingly, the Single Ownership Structure without the benefit of the ITC produced a higher average LCOE, ¢12.95/kWh (See Table 13).

The Sale Leaseback Ownership Structure resulted in the most expensive average LCOE at ¢13.50/kWh. However, those results are misleading; the average is exclusively created from the only Sale Leaseback output available. The SAM Sale Leaseback model only allows for the All Equity scenario. Including debt tends to reduce the LCOE of a project by spreading the large upfront costs over the lifetime of the project. It is likely that, given the ability to use financing, this ownership structure would have performed better. The Sale Leaseback structure resulted in lower LCOE than the All Equity Partnership Flip option. This suggests the possibility that a Sale Leaseback project with even midrange financing could contend with some of the more feasible ownership structure and financing combinations.

Table 10. List of all the ownership structure and financing options in order of lowest LCOE.

Ranking	Structures	Financing	LCOE (¢/kWh)	PPA (¢/kWh)
1	Partnership flip	CREB Low	9.36	9.83
2	Partnership flip	Municipal Bond Low	9.49	9.99
3	Commercial	USDA Loan	9.77	10.25
4	Partnership flip	USDA Loan	9.80	10.37
5	Commercial	Project Finance Low	9.89	10.48
6	Partnership flip	CREB High	10.22	10.93
7	Single Owner	CREB Low	10.81	11.36
8	Single Owner	Municipal Bond Low	10.95	11.52
9	Partnership flip	Project Finance Low	11.19	11.90
10	Partnership flip	Municipal Bond High	11.30	12.30
11	Single Owner	USDA Loan	11.38	11.99
12	Commercial	Project Finance High	11.47	12.21
13	Single Owner	CREB High	11.97	12.63
14	Partnership flip	Project Finance High	12.49	13.45
15	Single Owner	Project Finance Low	13.20	13.99
16	Commercial	All Equity	13.20	15.24
17	Single Owner	Municipal Bond High	13.24	14.01
18	Sale Leaseback	All Equity	13.50	14.45
19	Partnership flip	All Equity	14.31	16.05
20	Single Owner	Project Finance High	14.82	15.76
21	Single Owner	All Equity	17.26	19.87

It is remarkable how much more expensive the All Equity Single Owner scenario is than the other options. It is nearly ¢3 more than its closest contender and nearly double the lowest scenario (See Table 10). The Single Owner structure does not require any of the transaction costs associated with a tax equity structure, and the All Equity option does not require any transaction costs from acquiring financing. This option has some of the lowest costs and yet the other factors at play make it the worst economic option. This fits with Mendelsohn et al.'s prediction that having debt correlates with lower LCOE. Those authors expected including project level debt to reduce the LCOE by 20% to 50% as compared to All Equity scenarios. Counterintuitively, paying for the entire project in cash makes the project more expensive per kilowatt-hour. This is due to the time value of money concept; despite having to pay for debt servicing, not having to put up all the cash for initial costs makes projects with debt cheaper than All Equity projects.

Table 11. LCOE results and averages of Partnership Flip options.

Ownership Structure	Financing Option	LCOE (¢/kWh)
Partnership flip	CREB (Low)	9.36
Partnership flip	Municipal Bond (Low)	9.49
Partnership flip	USDA Loan	9.80
Partnership flip	CREB (High)	10.27
Partnership flip	Project Finance (Low)	11.19
Partnership flip	Municipal Bond (High)	11.30
Partnership flip	Project Finance (High)	12.49
Partnership flip	All Equity	14.31
	Average	11.03

Table 12. LCOE results and averages of Single Owner options.

Ownership Structure	Financing Option	LCOE (¢/kWh)
Single Owner	CREB (Low)	10.81
Single Owner	Municipal Bond (Low)	10.95
Single Owner	USDA Loan	11.38
Single Owner	CREB (High)	11.97
Single Owner	Project Finance (Low)	13.20
Single Owner	Municipal Bond (High)	13.24
Single Owner	Project Finance (High)	14.82
Single Owner	All Equity	17.26
	Average	12.95

Table 13. LCOE results and averages of Commercial options.

Ownership Structure	Financing Option	LCOE (¢/kWh)
Commercial	USDA Loan	9.77
Commercial	Project Finance (Low)	9.89
Commercial	Project Finance (High)	11.47
Commercial	All Equity	13.32
	Average	11.11

Table 14. LCOE results and averages of Sale Leaseback options.

Ownership Structure	Financing Option	LCOE (¢/kWh)
Sale Leaseback	All Equity	13.50
	Average	13.50

ITC vs Interest Rate

While it is certainly the ideal scenario, a low interest rate and ITC benefits may not be achieved in one project. Figure 11 plots out how the Single Owner, Partnership Flip and Commercial ownership structure models perform over an interest rate range of 0% to 8%. The Single Owner model was designed to illustrate the LCOE of the PV project without the ITC, and that is what it represents in this graph. The Partnership Flip and Commercial models are two different ways of structuring the ownership of a solar array while collecting the ITC. They both represent the LCOE potential over a spectrum of interest rates.

In Figure 11, the lower black line illustrates the lowest price the Single Owner model reaches, ¢10.81/kWh (See Appendix A). The model without the ITC cannot compete with a model that manages to capture it where the Commercial and Partnership Flip lines are below the black line. If a solar project with a structure that can capture the ITC can also secure an interest rate between 0% and approximately 3.4%, no structure without the ITC could compete with it. Ultimately, the only way for a structure that does not capture the ITC to be competitive is that it locks in a low interest rate and the other potential ITC capturing project cannot.

In Figure 11, the higher black line shows the most expensive a project with the ITC could be, given this spread of interest rates, approximately ¢13.30/kWh. Between the two black lines is where the projects could be competitive, given differing interest rates. If a project without the ITC procured financing between 0% and approximately 4.2% interest rate, it could have a chance to compete with a project that obtained the ITC, if it were between approximately 3.4% and 8%. For example, a Single Owner project with an interest rate of 1% without the ITC would produce a LCOE of ¢11.38/kWh, out-competing a Commercial project that can only obtain financing at 7%, resulting in a ¢12.7/kWh LCOE. However, it is doubtful that such a comparison would be useful as an evaluative tool since it is unlikely that a project with a LCOE of ¢11.38/kWh could be considered.

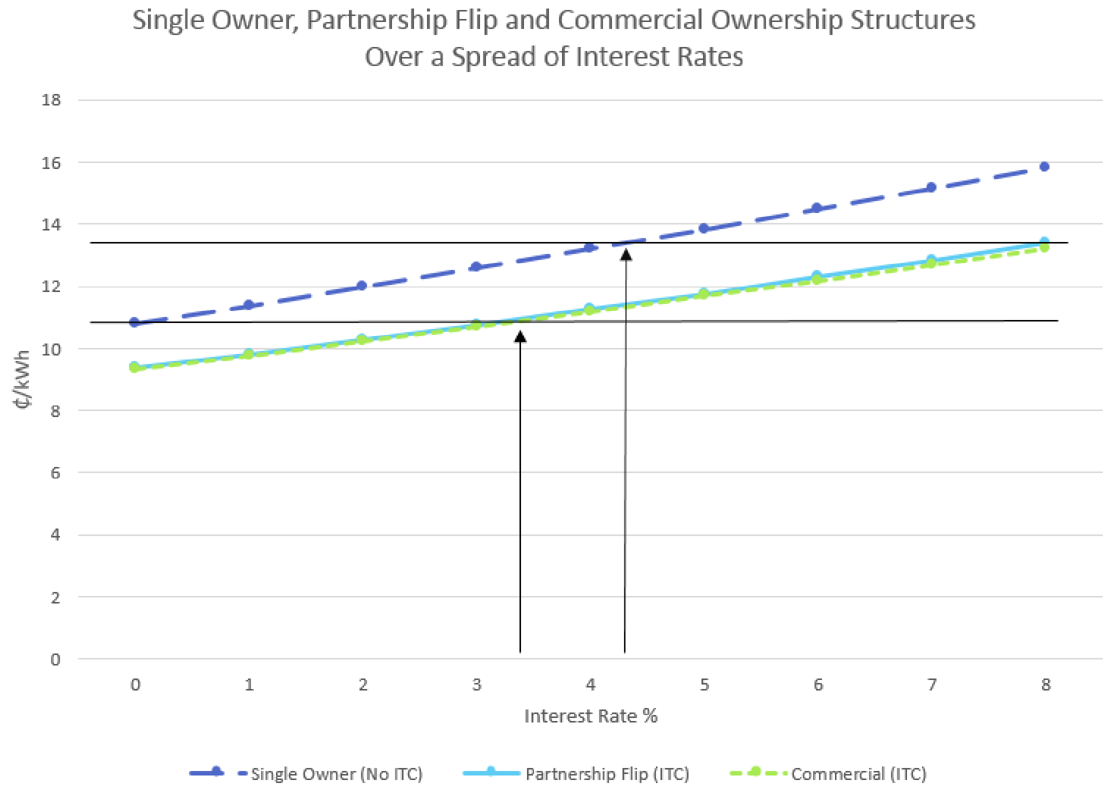

Figure 11. The LCOE of three ownership structures graphed over a range of interest rates. The bottom black horizontal line represents the lowest LCOE that the Single Owner could be. The higher black horizontal line is the highest LCOE that the Partnership Flip and Commercial structures could be in this example.

Another remarkable feature from Figure 11 is the similarity between the Partnership Flip and Commercial models' trendlines. In fact, the Single Owner and Commercial ownership models were built using the same base model and yet the Commercial model trendline is much more correlated with the Partnership Flip trendline. This indicates that acquiring ITC benefits is a determining factor in the economic viability of a solar project.

The Partnership Flip and Commercial model LCOE trend lines in Figure 11 are nearly on top of each other, but the Partnership Flip line is slightly more expensive. This may be due to the transaction costs required of a multiparty business venture. The Partnership Flip trendline has a steeper slope indicating that is becoming more expensive faster than the Commercial model's trendline.

Considering that the Partnership Flip and Commercial model lines represent ownership structures that can use the ITC and the Single Owner line cannot, it is remarkable how close similar they are. The Single Owner line is certainly not 30% higher than the other two lines. While the ITC is a powerful determinant of the economic viability of a project, other ongoing costs like operations and maintenance, debt servicing and transaction costs obscure the 30% discount. The ITC is 30% of the upfront costs but the upfront costs themselves are only a portion of the lifecycle costs of the project.

Transaction Costs

To learn about the effect of transaction costs on the overall economic viability of a solar array, I found the LCOE of all the ownership structure and financing option scenarios with differing percentages of the default costs (See Table 15).

Table 15. SAM's default values for transaction costs are incrementally shifted as inputs for the models.

% of Default Value	Debt Closing Costs	Equity Closing Costs
50%	$225,000	$150,000
60%	$270,000	$180,000
70%	$315,000	$210,000
80%	$360,000	$240,000
90%	$405,000	$270,000

First, we will examine the results of the sensitivity analysis on the Single Owner model. The Single Owner model incurs debt closing costs but does not have to pay the equity closing costs because it does not have a tax equity arrangement. The results from the sensitivity analysis show a marginal increase in the LCOE with each 10% increase in transaction costs (See Table 16).

Table 16. Results of the transaction cost sensitivity analysis on the Single Owner model LCOE in ¢/kWh, including the difference between the results of the least and most expensive scenarios.

% of Default Value	CREB Low	Municipal Bond Low	USDA Loan	CREB High	Project Finance Low	Municipal Bond High	Project Finance High
50%	10.17	10.3	10.69	11.23	12.34	12.37	13.81
60%	10.3	10.43	10.83	11.37	12.52	12.54	14.01
70%	10.42	10.56	10.97	11.52	12.69	12.71	14.21
80%	10.56	10.69	11.11	11.67	12.86	12.88	14.41
90%	10.68	10.82	11.24	11.82	13.03	13.06	14.62
100%	10.81	10.95	11.38	11.97	13.2	13.23	14.82
110%	10.94	11.08	11.52	12.12	13.38	13.4	15.02
120%	11.07	11.21	11.66	12.27	13.55	13.58	15.22
Change between 50% and 120%	0.9	0.91	0.97	1.04	1.21	1.21	1.41

The effect of the transaction cost percentage change is linear, but it varies between financing options (See Figure 12). The lines of the more expensive financing options have a slightly steeper slope than the more competitive scenarios. As is shown in Table 16, the change between the lowest transaction costs and the highest increases with the more expensive financing options. This effect is most notable for the higher interest rate Project Finance option.

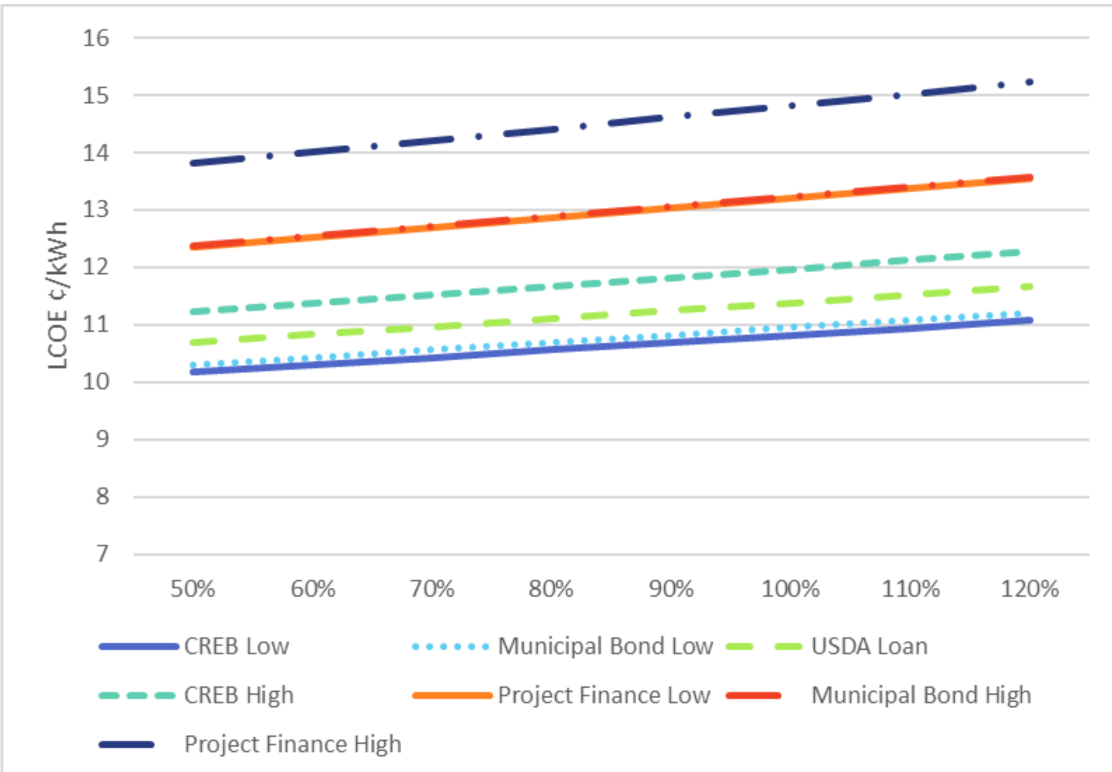

Figure 12. Results of the Single Owner model transaction cost sensitivity analysis graphically represented.

The transaction costs modeled for the Single Owner structure start at $225,000 and end with $540,000, making a $315,000 range of costs. Given $1,884,000 in fixed costs, the range of costs studied is about 16% of the amount of the project. The change in the LCOE from incrementally increasing transaction costs is a smaller percentage of the LCOE, between 8% and 10%. This indicates that the Single Owner model is not very sensitive to the change in transaction costs.

The Partnership Flip model includes equity closing costs in addition to the debt closing costs due to the expense of creating a legally binding relationship. The equity closing costs are about a third as large as the expense of securing debt, but it is still substantial (See Table 15).

Due to the increased total transaction costs, as compared to the Single Owner model, it is unsurprising that the change in the LCOE between 50% and 120% of the baseline is higher than with the previous model. However, it is not significantly higher. The baseline transaction costs went from $450,000 to $750,000, increasing by 67%, while the LCOE only increased by 12% to 14% (See Table 17). This further indicates the insensitivity of the LCOE in these projects to transaction costs.

Table 17. Results of the transaction cost sensitivity analysis on the Partnership Flip model LCOE in ¢/kWh, including the difference between the results of the least and most expensive scenarios.

% of Default Value	CREB Low	Municipal Bond Low	USDA Loan	CREB High	Project Finance Low	Municipal Bond High	Project Finance High
50%	8.59	8.75	8.97	9.37	10.21	10.32	11.34
60%	8.73	8.9	9.13	9.54	10.41	10.51	11.57
70%	8.88	9.05	9.28	9.71	10.6	10.71	11.8
80%	9.02	9.19	9.44	9.88	10.8	10.91	12.03
90%	9.17	9.34	9.6	10.05	10.99	11.1	12.26
100%	9.31	9.49	9.75	10.22	11.19	11.3	12.49
110%	9.45	9.63	9.91	10.38	11.38	11.49	12.72
120%	9.6	9.78	10.06	10.55	11.58	11.69	12.95
Change between 50% and 120%	1.01	1.03	1.09	1.18	1.37	1.37	1.61

Like the Single Owner model, the Partnership Flip model results indicate higher sensitivity to changes in the transaction costs with the more expensive financing methods. The most expensive option in this analysis, Project Finance High, has the steepest slope, indicating that it is the most sensitive to shifts in the initial costs. (See Figure 13).

Figure 13. Results of the Partnership Flip model transaction cost sensitivity analysis graphically represented in ¢/kWh.

Like the Single Owner model, the Commercial model only incurs debt closing costs and not equity closing costs. The Commercial model has the advantage of being able to exploit the ITC without having to use costly tax equity structures. For this reason, the LCOE is lower than the Single Owner model across all the financing options. As expected, the difference in the LCOE due to the change of the transaction cost baseline by 50% to 120% is less than the corresponding change in the Single Owner model (See Tables 16 and 18).

Table 18. Results of the transaction cost sensitivity analysis on the Commercial model LCOE in ¢/kWh, including the difference between the results of the least and most expensive scenarios.

% of Default Value	USDA Loan	CREB High	Project Finance Low
50%	9.23	9.34	10.78
60%	9.34	9.45	10.91
70%	9.44	9.56	11.05
80%	9.55	9.67	11.19
90%	9.66	9.78	11.33
100%	9.77	9.89	11.47
110%	9.88	10	11.61
120%	9.99	10.11	11.75
Change between 50% and 120%	0.76	0.77	0.97

The differences in the LCOE results between Single Owner, Partnership Flip and Commercial models and between the LCOEs of the financing options within the Ownership models indicate that the economics of solar projects are more sensitive to transaction costs the more expensive they become. However, the effect is relatively weak throughout all the examples. Within the bounds of this analysis, changing the amount of the transaction costs does not have a large effect on the competitiveness of the project and that result appears to be consistent across the different ownership structure and financing option combinations.

Feed-in Tariff

While RCEA does not currently have a FIT program, they expressed an interest in developing one in the near future (Redwood Coast Energy Authority, 2016). In order to approximate how successful the modeled solar arrays would be in a FIT, the FIT rates from SCP's ProFIT program were used for comparison. The base rate for ProFIT is 9.5 ¢/kWh. Including additional incentives, a 250-kW array on a brown field, using local labor with training incentives could potentially earn 13 ¢/kWh (Sonoma Clean Power, 2017). The PV arrays in this analysis would only be able to receive 12.5 ¢/kWh of the 13 ¢/kWh because their capacity is too large to take advantage of one of the additional incentives. In the following figures, the PPA rates are compared to SCP's ProFIT rates to estimate if the modeled projects could be financially feasible in a FIT program.

Figure 14 shows the PPA results from the Single Owner model without any tax incentives. This model includes the scenarios with the highest LCOE and PPA rates of all the models. None of these financing methods in combination with the Single Owner model has a low enough PPA rate to be financially feasible under a FIT program, such as ProFIT, at its base level. Half of the financing method scenarios could enter into the ProFIT program at 12.5 ¢/kWh, the high incentive rate. However, some of the requirements for the incentives, like building on previously used land, could increase the LCOE, moving it above the 12.5 ¢/kWh line. The lowest three PPA rates are far enough below the ProFIT with incentives line to enable them to afford to sell at the FIT program price even if the project costs increased modestly.

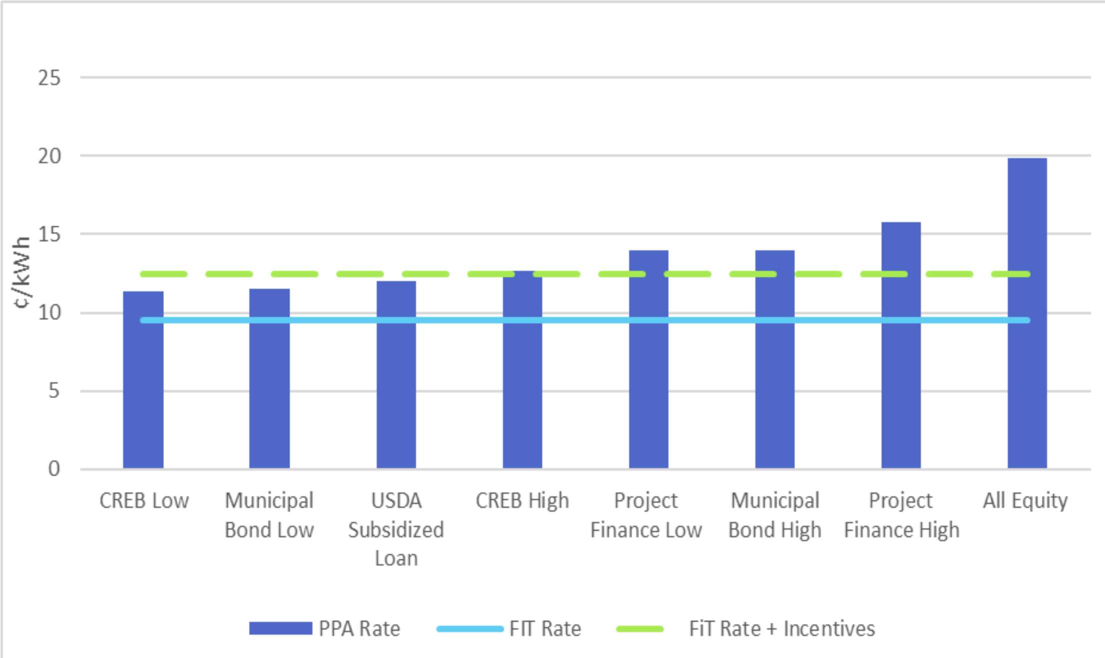

Figure 14. PPA rates for the Single Ownership with no tax based incentives ownership structures comparted to SCP's FIT rates in ¢/kWh.

As in the Single Owner model, the Partnership Flip model did not result in any scenarios in which the PPA rate is equal to or less than the baseline ProFIT rate (See Figure 15). The low estimate for CREB, which is based on a 0% interest rate, produced the closest at 9.83 ¢/kWh. The majority of the financing scenarios would be financially feasible with some or all of the additional incentives to boost the FIT rate.

Figure 15. PPA rates for the Partnership Flip ownership structure model comparted to SCP's FIT rates.

The PPA results from the Commercial ownership structure model are comparable to the Partnership results; none of the financing scenarios create PPA rates that are lower or equal to the ProFIT base rate (See Figure 16). Given one or two of the additional incentive rate increases, three-quarters of the scenarios could be economically feasible.

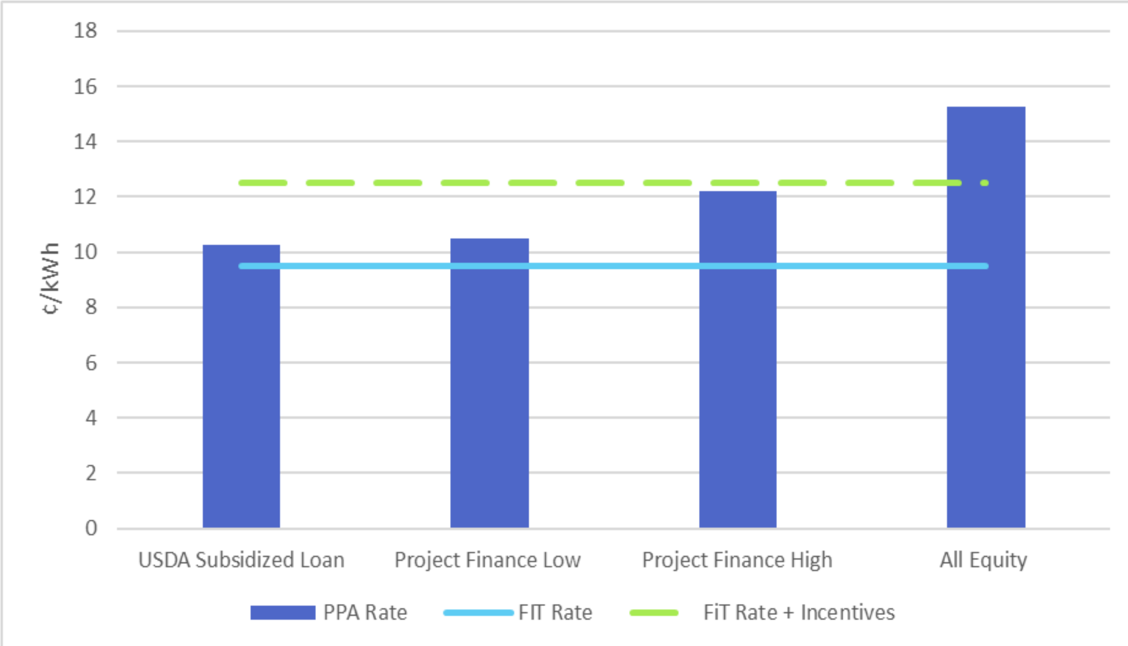

Figure 16. PPA rates for the Commercial ownership structure model comparted to SCP's FIT rates.

The Sale Leaseback model data, represented in Figure 19, display a particularly expensive way to generate energy compared to the other ownership structures. At ¢14.45/kWh, the All Equity Sale Leaseback option could not be reasonably enrolled in the ProFIT program in the base rate or even with all of the additional incentive rate increases. However, the SAM program only provides the option to model an All Equity financing scenario. In all four of the modeled ownership structures, the All Equity option is the most expensive. So, it is reasonable to hypothesize that the Sale Leaseback model would look better given other financing modeling options. In fact, of the four ownership structures, the All Equity scenario in the Sale Leaseback model is the cheapest. So, it is possible that this option might result in the best PPA rate if the more advantageous financing scenarios were applied.

Table 19. PPA rates for the Sale Leaseback ownership structure model comparted to SCP's FIT rates in ¢/kWh.

PPA Rate	FIT Rate	FIT Rate + Incentives
14.45	9.50	12.50

This analysis is intended to give a sense of how the results of these models stack up next to existing programs. It is important to remember that PPA rates are negotiable and not simply a product of the LCOE. The relationship that SAM provides between the LCOE and the PPA is an estimate based on the market average (SAM, 2017). If a project were to be based on one of the scenarios with a PPA rate slightly above the given FIT rate, it could choose to tighten the developer's returns and produce energy with slimmer margins.

Location

The location of the array, and the subsequent level of solar resource the array captures, has a large effect on the economic viability of a PV project. In Figure 17, the Arcata Airport project, which this thesis is based around, is compared to identical projects in Redding, CA and Crescent City, CA. Of the three locations, the Arcata project is clearly the most expensive across all the ownership structure and financing option combinations. The project located at the Crescent City Airport is slightly cheaper than in Arcata, and the project in Redding is the most competitive location.

It is unsurprising that Redding is the better location for a PV array. Redding is located inland and somewhat south of Mckinleyville, where the Arcata/Eureka Airport is situated (Googlemaps, 2017) (See Figure 18). However, the Crescent City airport is north of both of those locations and also along the coast. So, it is remarkable that the Crescent City project would be less expensive than the Humboldt County project. According to SAM, the Crescent City airport receives marginally more solar irradiance than the Arcata/Eureka airport and, therefore, a PV array sited there would produce more energy at a slightly cheaper rate. This difference could indicate what an undesirable site the Arcata/Eureka Airport is for solar generation and signal that this location is a bad indicator of solar resource for other parts of the County.

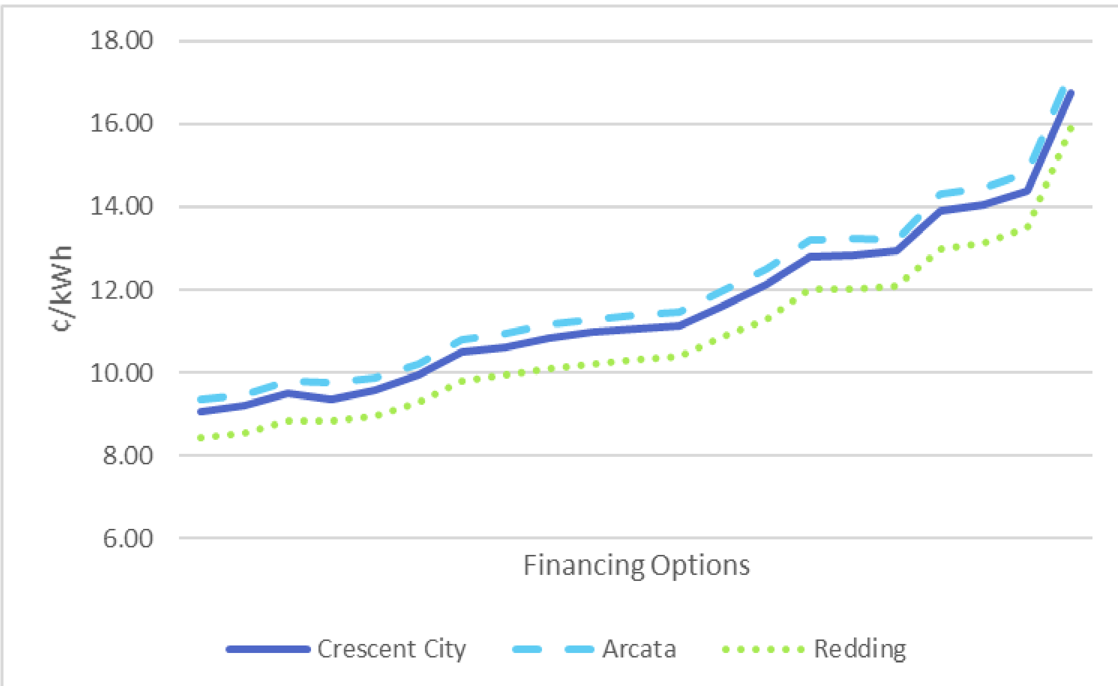

Figure 17. Results of the location sensitivity analysis for Arcata, Crescent City, and Redding across all the ownership structure and financing option scenarios in ¢/kWh.

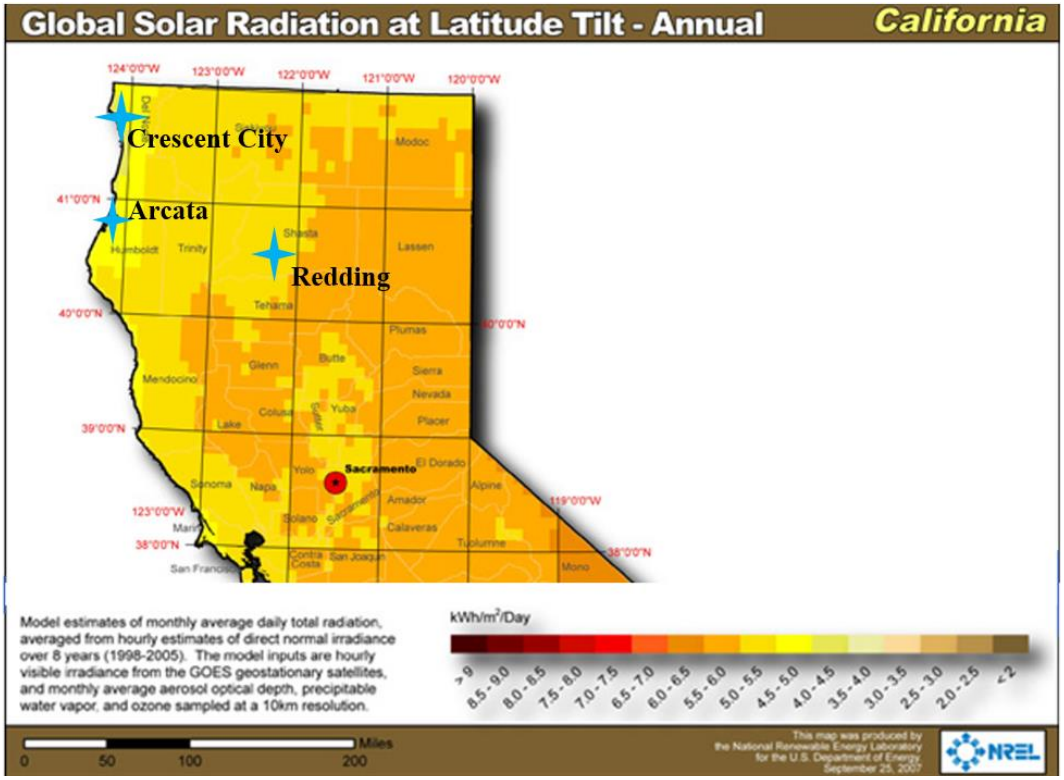

Figure 18. Solar Radiation Map of California. Adapted from the National Renewable Laboratory (NREL, 2017b)

Time of Construction

This project sought to approximate what effect delaying the start date would have on the lifetime economics of the array. The three most important considerations were the decrease in ITC benefits, the elimination of the MACRS bonus depreciation, and declining solar fixed costs. The relationship between those three factors provided interesting results. Predictions for the utility scale solar energy market expect prices to continue to decline, but the results of this analysis suggest that there will be bumps in the declining trend line (See Figure 19).

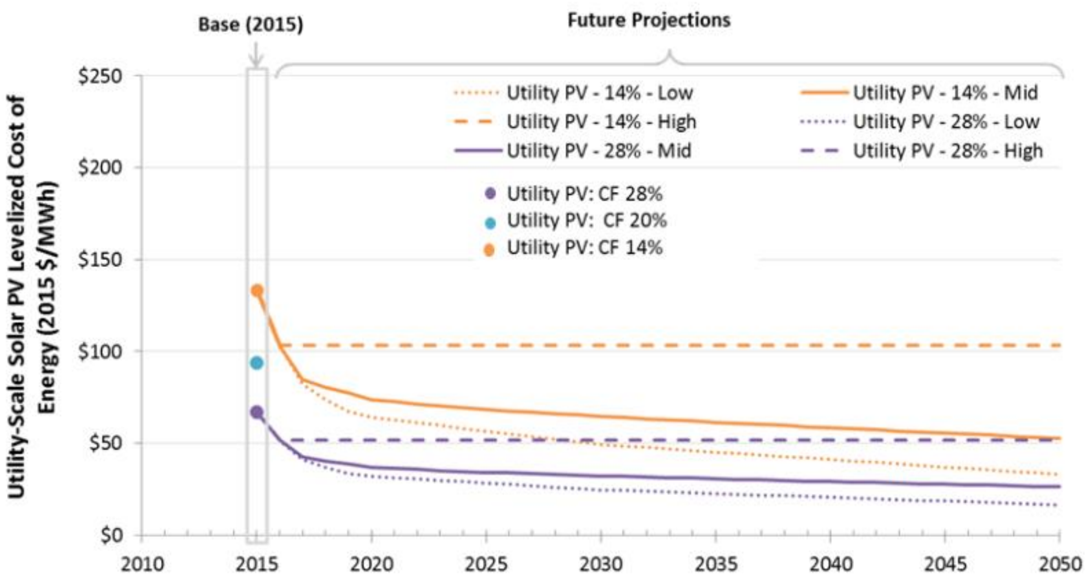

Figure 19. Plot of the expected cost of utility-scale PV solar energy through 2050 with estimates based on low, midrange and high levels of technological advancement (National Renewable Energy Laboratory, 2017a).

While the Sale Leaseback scenario does not have many data points to make conclusive arguments, the results of the sensitivity analysis point to a remarkable relationship between the tax benefits and falling PV installation costs over time. In 2018, the LCOE benefits from the full ITC and a 40% MACRS depreciation incentive while also having the most expensive cost per installed watt; this results in the lowest LCOE of the three years studied (See Figure 20). In 2020, the installed cost per watt declines, the ITC rate drops and the MACRS depreciation benefit evaporates. This combination of factors produces the most expensive LCOE of the three studied years. The next year, as the ITC continues its slow decline and the price of solar hardware and installation continues to drop, the LCOE begins to decrease again.

It appears that between 2018 and 2020 losing the MACRS was the determining variable causing the LCOE to increase. As the impact of losing the MACRS depreciation benefit wanes after 2020, the steady decline in the price per installed watt becomes the dominant variable, driving down the LCOE.

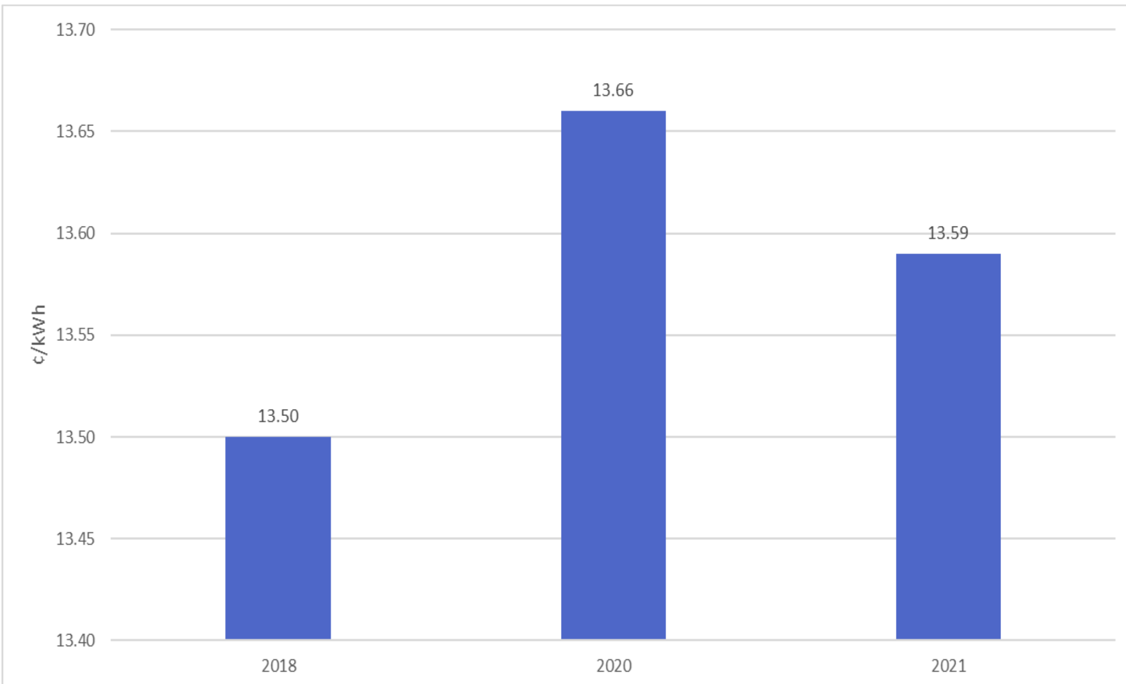

Figure 20. The LCOE for the Sale Leaseback ownership structure in 2018, 2020 and 2021 in ¢/kWh.

The Partnership Flip ownership model produced similar results to the Sale Leaseback model throughout the three studied years (See Figure 21). Losing the MACRS tax benefits in 2020, causes the LCOE to increase dramatically in all the financing scenarios. Then, between 2020 and 2021, the decline of the ITC benefits is at a much gentler rate than the decrease in the cost per installed watt, and the LCOE becomes more competitive again. This pattern can be observed across all the financing option scenarios.

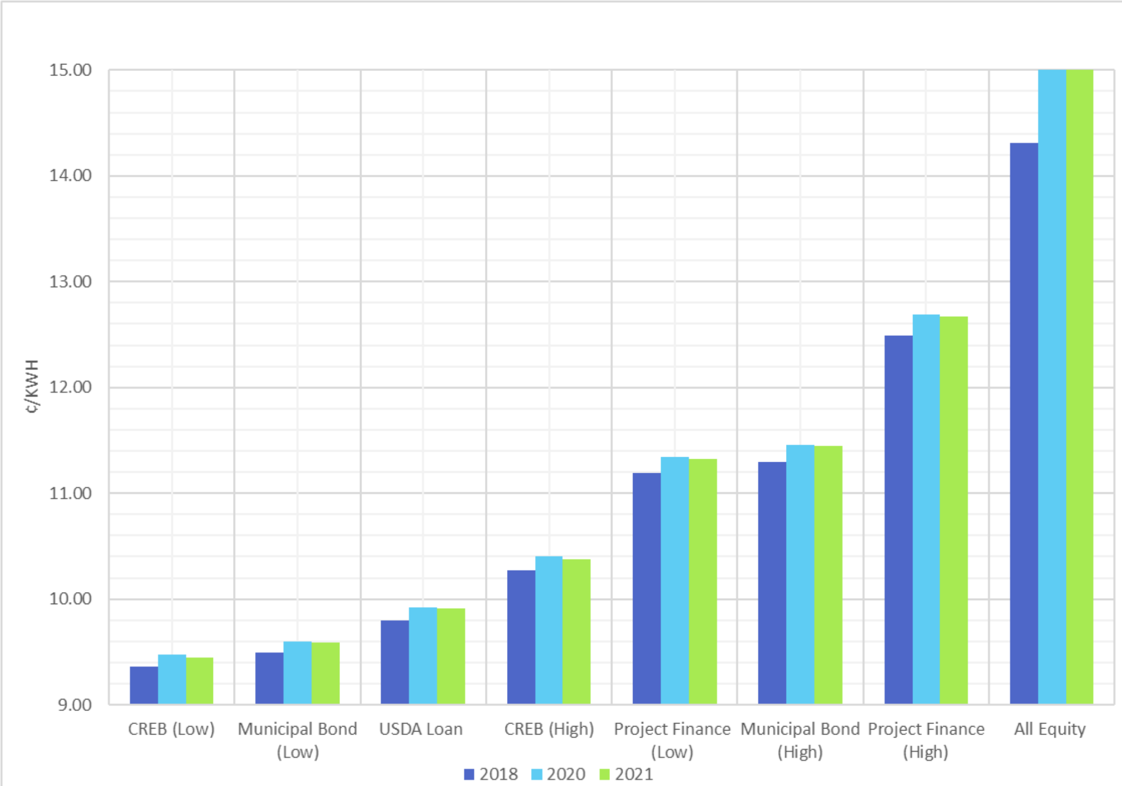

Figure 21. The LCOE for the Partnership Flip ownership structure in 2018, 2020 and 2021.

The Commercial model does not follow the same results pattern as the previous two ownership models (See Table 20). Despite losing the MACRS depreciation, the USDA Loan and All Equity scenarios both produce lower LCOEs in 2020 and 2021 than in 2018. The other two financing options, the high and low estimates for Project Finance, both follow the established pattern of a steep increase in the LCOE after losing the MACRS benefits in 2020 and then a slight decrease in the LCOE in 2021 as the cheaper cost per watt drags down the total.

Table 20. The LCOE for the Commercial Model from 2018 to 2021 in ¢/kWh.

Financing Option	2018	2020	2021	LCOE Change
USDA Loan	9.77	9.73	9.62	-0.15
Project Finance Low	9.89	9.97	9.92	0.03
Project Finance High	11.47	11.59	11.53	0.06
All Equity	13.20	13.19	12.97	-0.23

Unsurprisingly, the Single Ownership model demonstrated the greatest decrease in the LCOE over time. In this model, the developer does not capture the ITC, so the passage of time only decreases the fixed costs and does not remove any advantages. Once again, the decrease in LCOE is not evenly distributed among the various financing scenarios. This sensitivity analysis demonstrates a clear trend of the LCOE decreasing more rapidly in the more expensive scenarios (See Table 21). While the more expensive options become cheaper at a steeper rate than the more economic options, it does not make the most expensive options competitive, at least over this time frame.

Table 21. A comparison of the LCOE for the Single Ownership model with no tax incentives over the years 2018, 2020 and 2021 in ¢/kWh.

Financing Option	2018	2020	2021	Change from ’18 to ‘21
CREB Low	10.81	10.34	9.96	0.85
Municipal Bond Low	10.95	10.48	10.08	0.87
USDA Loan	11.38	10.88	10.46	0.92
CREB High	11.97	11.44	11.00	0.97
Project Finance Low	13.20	12.59	12.08	1.12
Municipal Bond High	13.24	12.62	12.10	1.14
Project Finance High	14.82	14.11	13.50	1.32
All Equity	17.26	16.22	15.36	1.90

Grant Funding

The grant funding portion of the USDA's Rural Energy for America program was not originally included in the calculation for the USDA Subsidized Loan financing option. Decreasing the project's fixed costs by approximately $50,000 resulted in small shifts in the LCOE (See Table 22). In the three ownership structure models with USDA Subsidized Loan options, the change in the LCOE after reducing the fixed costs was around 1%. It is worth noting that the various ownership structures produced differing reductions in the LCOE due to the grant funding but they were similarly small. On the other hand, $50,000 is approaching 3% of the total original fixed costs of the project. So, the decrease in fixed costs from a grant produces a reduction approximately one-third as large as the original reduction in the LCOE of a project.

Table 22. LCOE for the Subsidized Loan financing option with and without grant funding in ¢/kWh.

Ownership Structure	Original Treatment LCOE	LCOE: $50,000 Grant	LCOE Decrease	LCOE % Decrease
Single Owner	11.38	11.22	0.16	1.4%
Partnership Flip	9.75	9.68	0.07	0.7%
Commercial	9.77	9.64	0.13	1.3%
Grant Funding % of Total Fixed Costs				2.7%

Target Internal Rate of Return Variation

Overall, adjusting the target IRR by increasing and decreasing the rate by one percentage point from the base line made a very small difference in most cases (See Table 23 & 24). On the upper end, decreasing the target IRR by one had the effect of reducing the LCOE by approximately ¢1/kwh in the case of the Partnership Flip model with Municipal Bond (High) financing. The largest change in the LCOE from increasing the target IRR was a 0.83 ¢/kwh increase in the All Equity version of the Partnership Flip structure.

Table 23. Summary of the change in the LCOE as the target IRR increases by one percentage point for all the financing and ownership structure combinations in ¢/kWh.

Ownership Structures	**Financing Method**	**LCOE Base Target IRR**	**LCOE Target IRR +1%**	**Change in LCOE with +1% Target IRR**
Single Owner	CREB (Low)	10.81	10.8	-0.01
Single Owner	Municipal Bond (Low)	10.95	10.94	-0.01
Single Owner	USDA Loan	11.38	11.38	0
Single Owner	CREB (High)	11.97	11.97	0
Single Owner	Project Finance (Low)	13.2	13.21	0.01
Single Owner	Municipal Bond (High)	13.24	13.24	0
Single Owner	Project Finance (High)	14.82	14.85	0.03
Single Owner	All Equity	9.36	9.34	-0.02
Partnership Flip	CREB (Low)	9.49	9.47	-0.02
Partnership Flip	Municipal Bond (Low)	9.8	9.79	-0.01
Partnership Flip	USDA Loan	10.22	10.26	0.04
Partnership Flip	CREB (High)	11.19	11.79	0.6
Partnership Flip	Project Finance (Low)	11.3	11.3	0
Partnership Flip	Municipal Bond (High)	12.49	12.51	0.02
Partnership Flip	Project Finance (High)	14.31	15.14	0.83
Partnership Flip	All Equity	9.36	9.34	-0.02
Sale Leaseback	All Equity	13.5	13.87	0.37
Commercial	USDA Loan	9.77	9.63	-0.14
Commercial	Project Finance (Low)	9.89	9.89	0
Commercial	Project Finance (High)	11.47	11.5	0.03
Commercial	All Equity	13.2	13.69	0.49
Total Average				**0.13**

Table 24. Summary of the change in the LCOE as the target IRR decreases by one percentage point for all the financing and ownership structure combinations in ¢/kWh.

Ownership Structures	**Financing Method**	**LCOE Base Target IRR**	**LCOE Target IRR -1%**	**Change in LCOE with -1% Target IRR**
Single Owner	CREB (Low)	10.81	10.82	0.01
Single Owner	Municipal Bond (Low)	10.95	10.96	0.01
Single Owner	USDA Loan	11.38	11.39	0.01
Single Owner	CREB (High)	11.97	11.97	0
Single Owner	Project Finance (Low)	13.2	13.2	0
Single Owner	Municipal Bond (High)	13.24	13.22	-0.02
Single Owner	Project Finance (High)	14.82	14.79	-0.03
Single Owner	All Equity	17.26	16.78	-0.48
Partnership Flip	CREB (Low)	9.36	9.37	0.01
Partnership Flip	Municipal Bond (Low)	9.49	9.5	0.01
Partnership Flip	USDA Loan	9.8	9.81	0.01
Partnership Flip	CREB (High)	10.22	10.27	0.05
Partnership Flip	Project Finance (Low)	11.19	11.19	0
Partnership Flip	Municipal Bond (High)	11.3	10.29	-1.01
Partnership Flip	Project Finance (High)	12.49	12.46	-0.03
Partnership Flip	All Equity	14.31	13.58	-0.73
Sale Leaseback	All Equity	13.5	13.14	-0.36
Commercial	USDA Loan	9.77	9.64	-0.13
Commercial	Project Finance (Low)	9.89	9.89	0
Commercial	Project Finance (High)	11.47	11.44	-0.03
Commercial	All Equity	13.2	12.96	-0.24
Total Average				**-0.14**

The data in Tables 23 and 24 suggest that the effect of both increasing or decreasing the target IRR changes depending on the interest rate of the project in question. Lowering the target IRR increased the LCOE for the scenarios with the lowest interest rates in the Single Owner structure and the Partnership Flip structure (See Figure 22). What is remarkable is that these two structures are two of the most dissimilar of the four ownership structures. The Commercial structure does not fit the pattern of the previous two, considering that the LCOE of the USDA Loan scenario, which boasts a very low interest rate, decreased as the target IRR was lowered. The Sale Leaseback structure does not have an interest rate and so cannot be considered for the pattern.

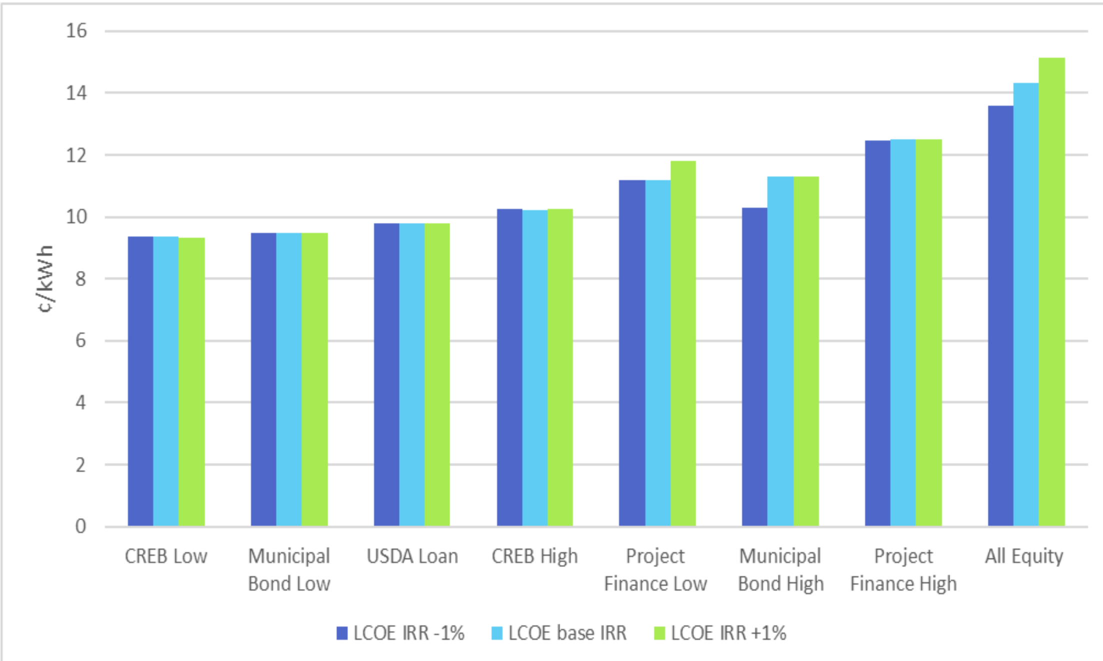

Figure 22. Results of increasing the target IRR by one percentage point across all the financing options in the Partnership Flip ownership structure.

By definition, the All Equity scenarios do not have interest rates that would interplay with the change in target IRR. However, in this analysis the All Equity scenarios seem to act like the higher interest rate financing options. As noted previously, the All Equity financing option produces the most expensive energy of all the scenarios. Perhaps the change in LCOE as produced by the shift of the target IRR is not dictated by the interest rate but some other factor that affects the LCOE.

Ultimately, the data suggest that modestly changing the target IRR of a project will not have a predictable effect. This appears to be a positive for a small entity negotiating with a large tax equity partner. The tax equity investor has a strong incentive to secure a high target IRR. Considering these results, the smaller partner would likely have every reason to cooperate and focus the negotiation on some other aspect that will have a great effect on the long-term success of the project. However, as the results of changing the target IRR do not seem to follow a predictable pattern, they should be modelled before any new policies are set for a real understanding of the chosen change's implications.

CONCLUSION

In support of RCEA's goal to contract five megawatts of local solar by the end of 2018, this project has examined the possible ownership structures and finance sources for a one-megawatt array in Humboldt County. There are a number of possible combinations of those two variables, which are investigated in this analysis. Many of the combinations of financing and ownership structure were modeled using the SAM program. Possible variations of those projects were also modeled, using the parametrics function of SAM, to better understand the relationship between different variables and the economic viability of the project as a whole.

The scenarios that are able to take advantage of the ITC are clearly more economically feasible even than projects with no debt servicing costs. There is no interest rate low enough for a project without tax incentives to compete with a project that can capture those benefits. Despite that fact, financing is still a crucial factor in the viability of a project.

Regardless of the ownership structure, using financing is a better approach than relying on equity from the controlling company exclusively. This was stressed in much of the literature and the modeled results bore out the same conclusion. The All Equity financing scenario was the most expensive across all the ownership structures.

The location of the solar array is a key determining factor for the economic outcome of the project. The analysis of location was constrained by only having solar irradiance data from a single site in Humboldt County. It is likely that there are other locations in Humboldt County with more plentiful solar resource that would reduce the cost of producing energy. The data from the SAM model suggest that choosing a sunny location, even in the neighboring counties, may be a reasonable option in service of an affordable LCOE. Building a PV array in a neighboring county may be less politically tenable for RCEA but if the installation work was done by a local company it could still retain enough of the vestiges of local solar.

The target IRR that a tax equity partner requires is not a strong determinant of the economic viability of a project. So, if a project is working with a tax equity partner, that may be a good place to acquiesce to their demands and negotiate more vehemently on other points. According to the SAM results, transaction costs do appear to contribute to the LCOE, but they are not a defining variable in the way that location and the MACRS depreciation incentive seemed to be. Solar projects appear to be more sensitive to transaction costs the larger they become, but it is still not a defining feature of the project. Together, the transaction cost and target IRR variables could change the competitiveness of a project, but there is some room to be flexible with those variables.

The two lowest cost scenarios were tax equity partnership flips that would require access to government financing, the CREB and the Municipal Bonds. This analysis could not accurately capture the increase in transaction costs from accessing these two forms of financing. As demonstrated in the transaction cost sensitivity analysis, those increased costs may not make the projects infeasible, but it could increase their LCOEs.

A commercial project that accesses USDA subsidized financing resulted in the third lowest LCOE in the analysis. It is possible that this would be the lowest cost option for building solar capacity in Humboldt County. Determining which industries could benefit from the ITC of a multi-million-dollar project would be the next step in assessing if this approach could bear fruit in Humboldt County.

The timeframe for starting a project will play a crucial role in the economic viability of any proposed solar array. A project initialized by the end of 2018 will have the benefit the MACRS depreciation and the full ITC, which is a crucial advantage. The cost of the hardware and installing solar has decreased rapidly and is expected to continue on this trend, but the results of this analysis suggest that the declining cost per installed watt will not make up for the tax incentives tapering out for some years. In addition, price forecasting, like any kind of prediction, becomes more dubious the farther out the projection. So, it could make sense for RCEA to contract for the first five megawatts of solar as soon as possible, then focus on other local sources of renewable energy, until towards the end of the five-year period to encourage the next ten megawatts of solar.

Solar energy generation in Humboldt County must contend with a number of challenges. While it may remain more expensive than energy from solar arrays in sunnier parts of the state, there are reasonable options for RCEA to satisfy its goal of contracting for five megawatts of local solar by 2018 and catalyzing the utility scale solar industry in the Humboldt County.

Recommendations for Future Research

Bundling smaller projects together is a useful tool in accessing tax benefits through a tax equity flip and thus minimizing transaction costs. In the case that RCEA wants to own a solar project, bundling it with other small projects in a large-scale tax equity partnership flip, while using subsidized financing like CREBs, could result in the most feasible LCOE. Unfortunately, a bundled ownership structure was outside of the scope of the SAM model and therefore is not considered here. Modeling a set of bundled projects would be an excellent next step for further research.

I attempted to run a sensitivity analysis on the capacity of the system, testing the economies of scale, but this model does not have the nuance to investigate that facet of the project. Exploring the effect that size would have on a similar project in Humboldt County could be very informative and useful.

Based on the literature, Community Solar seems like a good fit for the culture of Humboldt County. Unfortunately, the unique structure of a Community Solar project could not be modeled with the SAM program. Further research could examine the economic viability of a Community Solar array using more malleable modeling software.

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APPENDIX

Appendix A. The tables included in Appendix A contain data from the results of the analysis.

Table A.1 LCOE for three different ownership structures with interest rates between zero and eight percent in ¢/kWh.

%	**Single Owner (No ITC)**	**Partnership Flip (ITC)**	**Commercial (ITC)**
0	10.81	9.36	9.32
1	11.38	9.8	9.77
2	11.97	10.27	10.23
3	12.58	10.75	10.71
4	13.2	11.25	11.19
5	13.84	11.76	11.69
6	14.49	12.29	12.19
7	15.15	12.83	12.7
8	15.81	13.39	13.23

Table A.2 LCOE for the Single Owner model with FIT rates in ¢/kWh.

Financing Method	**PPA Rate**	**FIT Rate**	**FiT Rate + Incentives**
CREB Low	11.36	9.5	12.5
Municipal Bond Low	11.52	9.5	12.5
USDA Subsidized Loan	11.99	9.5	12.5
CREB High	12.63	9.5	12.5
Project Finance Low	13.99	9.5	12.5
Municipal Bond High	14.01	9.5	12.5
Project Finance High	15.76	9.5	12.5
All Equity	19.87	9.5	12.5

Table A.3 LCOE for the Partnership Flip model with FIT rates in ¢/kWh.

Financing Method	**PPA Rate**	**FIT Rate**	**FiT Rate + Incentives**
CREB Low	9.83	9.5	12.5
Municipal Bond Low	9.99	9.5	12.5
USDA Subsidized Loan	10.37	9.5	12.5
CREB High	10.93	9.5	12.5
Project Finance Low	11.9	9.5	12.5
Municipal Bond High	12.3	9.5	12.5
Project Finance High	13.45	9.5	12.5
All Equity	16.05	9.5	12.5

Table A.4 LCOE for the Commercial model with FIT rates in ¢/kWh.

Financing Method	**PPA Rate**	**FIT Rate**	**FiT Rate + Incentives**
USDA Subsidized Loan	10.25	9.5	12.5
Project Finance Low	10.48	9.5	12.5
Project Finance High	12.21	9.5	12.5
All Equity	15.24	9.5	12.5

Table A.5 LCOE for Arcata, Crescent City, and Redding in ¢/kWh.

Ownership Structure	**Arcata**	**Crescent City**	**Redding**
Single Owner	9.36	9.08	8.14
Single Owner	9.49	9.21	8.26
Single Owner	9.77	9.35	8.38
Single Owner	9.80	9.51	8.52
Single Owner	9.89	9.60	8.60
Single Owner	10.22	9.97	8.93
Single Owner	10.81	10.49	9.40
Single Owner	10.95	10.63	9.52
Partnership flip	11.19	10.85	9.72
Partnership flip	11.30	10.97	9.82
Partnership flip	11.38	11.05	9.90
Partnership flip	11.47	11.13	9.97
Partnership flip	11.97	11.62	10.41
Partnership flip	12.49	12.12	10.86
Partnership flip	13.20	12.81	11.48
Partnership flip	13.20	12.84	11.50
Sale Leaseback	13.24	12.93	11.58
Commercial	13.50	13.10	11.74
Commercial	14.31	13.89	12.44
Commercial	14.82	14.38	12.89
Commercial	17.26	16.75	15.00