

MEMO

This memo was originally sent on April 10, 2008. Given changes that have taken place in Arizona, it has been updated with input from the City of Tucson.

To: **June 28, 2008**

From: **Bruce Plenk
City of Tucson**

Date: **Jason Coughlin
National Renewable Energy Laboratory**

Subject: **Solar America Cities - Financial discussion**

Financing the installation of public sector photovoltaic (PV) systems requires an evaluation and analysis of the various mechanisms available to local governments in the current marketplace. In most cases, different incentives must be combined in order for the deployment of a PV system to make economic sense. Tax incentives in particular play a very important role in the financing of PV systems. Until recently, public sector entities have been at a disadvantage given their inability to monetize these tax benefits - save for creative programs such as the Oregon Business Energy Tax Credit (BETC) which allows government agencies to sell their tax credits to tax paying entities.¹ However, the emergence of third party models and the use of the Power Purchase Agreement (PPA) now provide a mechanism for public entities to leverage these tax incentives. As a result, many cities are evaluating how the third party model fits into their overall plans for installing public sector PV installations going forward.

The city of Tucson has significant experience deploying PV systems on public facilities. The city's designation as a Department of Energy Solar America City (SAC) recognizes this experience. As part of the statement of work between Tucson and the SAC program, the city requested the following information:

For the purposes of financial planning, provide descriptions and comparative analyses of the strengths/weaknesses of funding sources including: CREBS, REST, government incentives, and third-party financing options.

The following memo was prepared by Jason Coughlin of the National Renewable Energy Laboratory (NREL) in order to address these topics. This memo draws extensively from an NREL technical report which was released in May 2008 and covers many of the topics in more detail. The paper, titled “*Solar Photovoltaic Financing: Deployment on Public Property by State and Local Governments*”, was co-authored by Coughlin, Karlynn Cory, and Charlie Coggeshall. The report is available at the following link.
www.nrel.gov/docs/fy08osti/43115.pdf



1.0 Introduction

Despite technological advances, PV systems are still expensive in today's marketplace. Reducing the upfront cost of the system and financing the residual installation costs continue to be a challenge for local governments. However, with the emergence of third party financing models, cities now have an additional mechanism at their disposal to finance the installation of PV systems on public buildings. The third party model does however create a question of the importance and timing of ownership for a given PV system.

If it is important or legally required that Tucson take ownership of a PV system upon installation, then the options available to finance it are limited to a sub-set of the universe of available PV financing mechanisms in the marketplace. Tucson can use proceeds from traditional tax exempt financing or other sources of city revenues and combine them with incentives from Tucson Electric Power's SunShare incentive program and other available grants. This is likely the standard practice to date for financing PV in the City. With the introduction of Clean Renewable Energy Bonds (CREBs), tax-exempt financing can be replaced with "interest-free" financing which can then be combined with SunShare incentives and other grant monies as available. The transition to production-based incentives under the Renewable Energy Standard Tariff (REST) will likely have an impact on the City's choice of financial structures as Tucson will now need to finance more of a system's cost upfront.

If immediate ownership is less of a priority, or if the city lacks the necessary capital for the upfront investment, then the third party financing model may be the more appropriate solution. Under this model, the city of Tucson would agree to host (but not own) a PV system on a public rooftop or public space. In lieu of initial ownership, Tucson agrees to purchase electricity from the third-party for a fixed period of time (20 years is common). Under this structure, it is the third party that would receive the production-based incentives in addition to the various state and federal tax incentives available to it as a tax-paying entity. While Tucson relinquishes initial ownership of the system under the third party model, ownership options (commonly after year six) can be built into the PPA agreement.

This memo will review the requested financial incentives and mechanisms available to the City of Tucson, discuss their advantages and disadvantages, and provide some examples of how other cities have put them into practice to deploy public sector PV systems.

2.0 Federal, State, and Utility Incentives

Monetizing available incentives is critical to financing PV systems. There is a wide array of incentives at the federal, state, and utility level. Many of these incentives are tax-based which has traditionally excluded public sector entities from taking advantage of them.

Federal Tax Incentives

There are significant federal tax incentives for private sector entities that purchase and own PV systems. These incentives provide tremendous value to the owner and significantly reduce the installed cost of the system. Given that the Federal Investment Tax Credit (ITC) and Modified Accelerated Cost Recovery System (MACRS) can account for 40-60% of the installed cost of a PV system,² these incentives dramatically alter the economic viability of installing solar PV systems.

o Investment Tax Credit (ITC)

For commercial entities, the Federal government currently offers a 30% investment tax credit to partially offset the up-front installed cost of a PV system.³ This credit will revert back to 10% as of January 1st, 2009 if Congress does not reauthorize it. The system owner can use this credit to

reduce his tax burden. As an example, a PV system with an installed cost of \$1 million will qualify for a \$300,000 tax credit. The rules associated with the ITC are complex and a tax lawyer should review its application. Certain incentives can reduce the value of the ITC and the ITC can impact the depreciable basis of the underlying asset as well. The Solar Energy Industry Association's *Guide to Federal Tax Incentives for Solar Energy* provides good background information and incentive detail.⁴

- **Modified Accelerated Cost Recovery System (MACRS)**

As defined by the IRS, "depreciation is an income tax deduction that allows a taxpayer to recover the cost or other basis of certain property. It is an annual allowance for the wear and tear, deterioration, or obsolescence of the property."⁵ Depreciation schedules can range from 3 to 50 years depending on the asset.⁶ It is a non-cash charge recorded as a depreciation expense for tax purposes. Most property today is depreciated using MACRS.⁷ The IRS allows commercial owners of PV systems to use a 5-yr MACRS schedule.

Depreciation reduces an entity's taxable income and subsequently, its tax burden. The shorter the depreciation schedule, the greater the percentage of the asset that can be depreciated each year. So in the case of PV, 5-yr MACRS is more advantageous than longer depreciation schedules, all else being equal, because a shorter schedule allows businesses to accelerate the tax benefits of depreciating the PV system.

- **Bonus Depreciation⁸**

The Economic Stimulus Act of 2008 (ESA08) contains bonus depreciation for qualifying assets placed in service in 2008. Renewable energy installations, including PV systems, may qualify for this bonus depreciation if certain criteria are met. Instead of the standard 5-yr MACRS schedule described in the preceding paragraph, under the ESA08, 50% of the installed cost of the PV system can be depreciated in the first year, with the remaining 50% to be depreciated over the original schedule. By accelerating the amount of depreciation in year one, tax benefits will accrue more rapidly to investors, improving the return characteristics of the project. The requirement that the depreciable basis of the underlying asset be reduced by 50% of the federal investment tax credit did not change.

State Tax Incentives

State tax incentives also provide benefits to tax paying entities although they are not traditionally as generous as federal tax incentives. According to the North Carolina Solar Center's Database for State Incentives for Renewable and Efficiency (DSIRE), Arizona has a number of state-based tax incentives at the corporate level.⁹ The non-residential corporate tax incentive provides a 10% tax credit up to \$25,000 per building.¹⁰ It appears that this incentive was modified in 2007 to provide additional flexibility to tax exempt entities and third parties. Arizona offers a state sales tax exemption for qualifying solar equipment¹¹ as well as a property tax incentive.¹²

Tucson Electric Power - Renewable Energy Standard Tariff (REST)

As a mechanism to finance compliance with the state's Renewable Energy Standard (RES), as of May 2008, Tucson Electric Power (TEP) will increase the fee added to its customers' utility bills.¹³ This fee, approximately one half-cent per kWh, will now be called the Renewable Energy Standard Tariff (REST) and will replace the Environmental Portfolio Surcharge (EPS). Initially, TEP has decided to allocate 80% of the funds raised from the REST to residential PV systems with the remaining 20% going to non-residential systems.

The use of a fee -often called a system benefit charge (SBC) or public benefit charge- is a common source of funding for PV incentives in many states. Since the mid 1990's, 17 states

(including the District of Columbia)¹⁴ have implemented some variation of the SBC to support renewable energy.¹⁵ The implementation of these SBC programs, for the most part, has been the result of electric utility restructuring legislation approved over the past ten years.¹⁶ While the fee is usually modest to the consumer, in aggregate, significant funds are generated using this mechanism. According to the North Carolina Solar Center, between 1997 and 2017, \$6.8 billion dollars will be raised via the system benefit charge system.¹⁷ California alone will collect \$331 million in 2008 under this mechanism.¹⁸

In Tucson, under the new REST structure, TEP will continue to provide subsidies for PV systems through its SunShare program.¹⁹ The upfront \$3.00/watt incentive (UFI) will remain in place for residential grid-tied customers and \$2.50/watt will be paid upfront for non-residential, grid-tied systems up to 20 kW. However, and most significant, is the implementation of a production-based incentive (PBI) for non-residential, grid-tied PV systems greater than 20 kW. The PBI will be paid out quarterly and will be based on the actual generation of solar electricity by a given system. In return for receiving the PBI, the system owner will sell the rights to the renewable energy credits (RECs) that the system generates. This REC agreement will be in place for as long as the PBI is being paid out to the system owner (e.g. 10, 15, or 20 years). In the case of the UFI, TEP will acquire the REC rights for 20 years.

Both the UFI and the PBI can be combined with other incentives. However, in order to ensure that the system owner invests its own capital in the project, neither the UFI or the PBI can represent more than 60% of the cost of the system. In addition, TEP will require a minimum 15% contribution from the system owner. This may reduce the actual UFI or PBI pay-out depending on the additional incentives that the system owner is able to obtain.

TEP has published its table of production-based incentives as an appendix in its April 19, 2008 RECPP Manual.²⁰ TEP is attempting to create a market-based system for allocating the PBI and as a result is encouraging potential program participants to bid in their PBI requests at a rate lower than the maximum in order to improve the chances of being selected. Therefore, the City of Tucson will need to determine the level at which it will bid for PBIs over a 10-yr, 15-yr or 20-yr period. According to the RECPP Manual, in 2008 and 2009, the maximum incentives are 20.2 cents/kWh, 18.7 cents/kWh and 18 cents/kWh for 10, 15, and 20-years, respectively.

The dilemma posed by this competitive bidding process is that the City must bid high enough to recover as much of the initial capital investment as possible (*and not leave any money on the table*) but not bid so high that the bid is not accepted. There is a caveat in that the Manual does refer to the situation where all bids will be accepted if program funding exceeds demand. These incentives are scheduled to decrease on a kWh-basis in 2010-2011, and again in 2012.

New Jersey and California are also in the process of transitioning from a system of upfront incentives to a system of production-based incentives (PBI).^{21,22} In the case of California, the PBI will be paid out for 5 years whereas in New Jersey, solar RECs will be sold into the marketplace as PV systems generate them over their useful lives.^{23,24} A positive element in California's PBI program is that government agencies get a higher production incentive given their inability to benefit from the various tax incentives available to tax-paying entities.²⁵

The introduction of the PBI for larger systems will have a noticeable financial impact as upfront cash incentives are redirected to later years. Even if the economic value of the incentives is equal across time on a present value basis, a shift away from upfront incentives to production-based incentives increases the upfront investment needed to deploy PV. In other words, the same size system will now require a larger upfront capital investment or for a given amount of resources,

the system size that can be financed will be reduced. As a result of the transition to a PBI, the third-party finance model may become even more attractive to public entities in Tucson as a mechanism to avoid this initial (and now higher) investment.

Customer Self-Directed Renewable Energy Option

According to a review of various documents from both the ACC²⁶ and TEP,²⁷ it does appear that entities that pay \$25,000 or more in surcharges under the REST program in a given year can apply to participate in the customer self-directed renewable energy option. The money available under this option is capped at the total REST payments made by an entity in a given calendar year. Since the City of Tucson will fall into this category, it should have the option to apply for the self-directed funding option if it is unsuccessful bidding into the PBI program. It is not clear whether or not an entity that receives funding under the self-directed option can also participate in the standard UFI and PBI programs. As with the standard programs, TEP will take ownership of the RECs under the self-directed option as well.

Renewable Energy Credits (RECs)

RECs²⁸ have become the dominant mechanism for compliance with renewable portfolio standards (RPS) and for voluntary green power purchases. RECs are commodities with monetary value, separate from the electricity produced, that bundle the “attributes” of renewable electricity generation. The definition of "attributes" can vary across contracts but will likely include any future carbon trading credits, emission reduction credits, and emission allowances, among others. One REC typically represents the attributes of 1 megawatt-hour (MWh) of renewable electricity generation and therefore, it is interesting to see that TEP is defining a REC as the environmental attributes generated by one kWh of renewable energy.²⁹ Once the REC is separated from the underlying electricity and sold to another party, claims to the attributes can only be made by the REC owner, and not by the electricity owner or the owner of the project.

As mentioned above, RECs will be transferred to the utility as a condition of receiving either the UFI or the PBI. This is common as RECs are often used by utilities to demonstrate compliance with their states' Renewable Portfolio Standard (RPS). As stated, in the case of the UFI, TEP will own the RECs for 20 years. In the PBI program, TEP will own the RECs for the duration of the PBI contract.

3.0 Financing Mechanisms for Public Sector PV

Once the universe of potential incentives is understood, the next step is to determine the financial instruments and structures that can be combined with these incentives to install PV systems in an economically viable manner. Included in this section is an analysis of third party PPA models, clean renewable energy bonds (CREBs), and tax-exempt renewable energy bonds. As noted, Tucson is familiar with many of these instruments having received allocations for the issuance of CREBs from the Internal Revenue Service (IRS) in addition to being in the midst of the RFP process for PPA-funded PV projects

3.1 Third-Party Finance Models and the PPA

In the public sector PV marketplace, some local governments are moving away from direct ownership of PV systems and towards the use of partnering with third-party owners. While

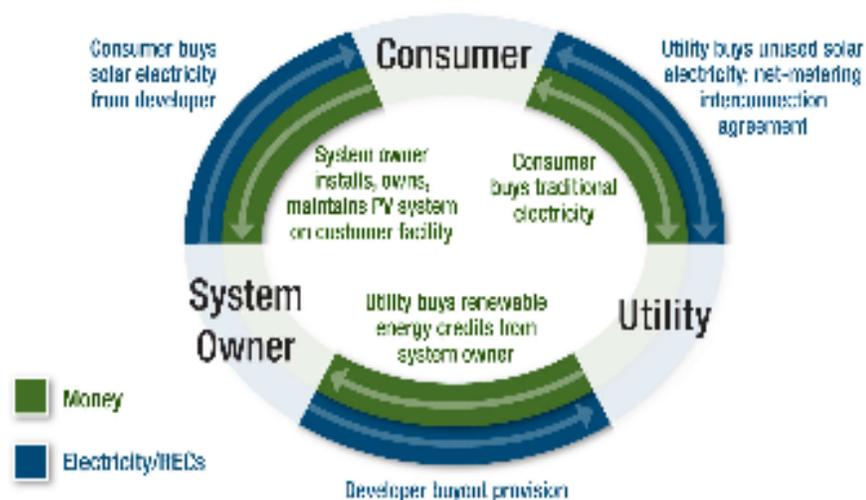
common in the private sector, the use of third-party ownership structures is still a relatively new phenomenon in the public sector. According to Greentech Media, in 2007, 50% of the growth in the commercial and institutional market for solar in the United States was carried out using the third-party owner model compared to just 10% in 2006.³⁰ State and local governments see the third-party ownership model as a way to effectively monetize federal tax benefits, avoid paying

the up-front cost of solar, more efficiently allocate public funds, and accelerate the deployment of PV.

Instead of owning the PV system, a public entity hosts a system that is paid for and owned by a taxable entity. The public entity enters into a long-term contract (the "PPA") with a third-party to purchase the electricity generated on its property. The electricity price is typically set at or below the host's current retail rate for the first year, and then it will typically escalate at some fixed percentage over time. The developer manages all aspects of system financing, installation, and maintenance, and bears all standard operating risks.

Benefits of the third-party ownership structure include no upfront capital costs, known electricity prices purchased from the system for 20-25 years, no responsibility if the system does not perform over time (except to purchase more power from their utility), and a shift in the O&M responsibility on to a qualified party. Examples of the third-party ownership structure in place in the public sector include PV facilities at an airport,³¹ a water treatment plant,³² and a port,³³ to name a few.

Figure 1. Contracts and Cash Flow in Third-Party Ownership Model



Source: Department of Energy Solar Program

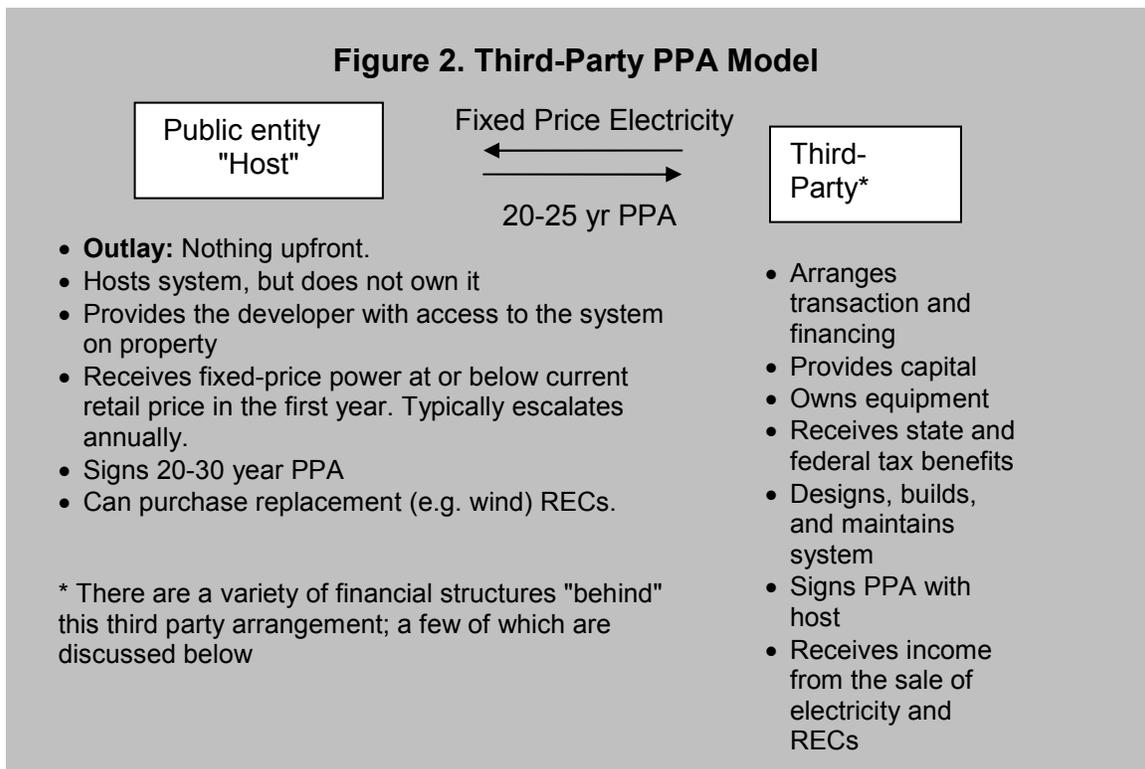
While the third-party owner model is attractive, there are some important disadvantages and caveats – most notably, if the SRECs are sold, then the municipality cannot claim they are getting green power unless they buy replacement RECs.³⁴ Another issue is that even though the public entity has solar PV on-site, it still must pay for the electricity the system generates through the PPA (rather than reducing its overall electricity purchases). Also, the partners in the third-party ownership model must have access to the site where the PV system is located. Transaction costs can be significant and there are some specific contracting issues that require attention. Very recently, the issue of the legality of the PPA has come up in Nevada and has been raised by Commission staff in Arizona. Finally, while not a disadvantage per se, the equity of below market rates in a PPA when public funding is involved has been raised in one instance at the state level. These challenges are explored below.

Advantages of Third-Party Ownership

There are several key reasons why more state and local governments are considering the third-party PPA an integral component of their PV strategy.

- Ability to Monetize Federal Tax Incentives: As noted, at the present time (until 12/31/08) the federal ITC for commercial solar projects is 30% of the installed capital cost. In addition, businesses can accelerate the depreciation of the cost of a solar system using a 5-yr MACRS. Together, these two tax incentives have a tremendous impact on both the cost of and the financial returns on a project. However, as non-tax paying entities, state and local governments cannot benefit from these attractive incentives if they own PV systems. The third-party ownership model introduces a taxable entity into the structure that can benefit from the federal tax incentives, lowering the overall cost to the non-taxable entity.
- Low/No Upfront Costs: PV systems are not cheap. For example, at \$9-10 per installed watt in parts of California,³⁵ public sector PV systems (above 100 kW) can easily cost hundreds of thousands of dollars and higher. Even if rebates and incentives reduce this amount, the upfront cost is still significant. Given budget constraints, committing to such a large initial investment, even if the long-run economics make sense, is not always feasible. The third-party ownership structure pushes this initial cost on to the solar developer and its investors.
- Pre-Determined Electricity Price for 20-25 years: In today's volatile energy markets, a fixed-priced PPA (with an escalation rate) offers predictable electricity pricing for the portion of the entity's load served by the PV system. To make the third-party ownership model work, the price of electricity is usually set at or below the customer's current retail rate for the first year, and then escalates annually for 20-25 years. This structure provides a price hedge against the potential volatility of both fossil fuel and electricity markets. An annual price escalator of 3-3.5% is common in today's marketplace³⁶ although smaller escalators are possible. For example, San Francisco's bus company, AC Transit, has signed a 20-yr PPA with MMA Renewable Ventures with a 2.5% price escalator.³⁷
- Shift O&M Responsibility to Qualified Third-Party: Owning a large PV system implies a certain degree of oversight and maintenance that a public entity may not want to be responsible for or have the expertise to carry out. One of the attractive features of the third-party ownership structure is the ability to assign the operation and maintenance of the PV system to more qualified counterparties. The third-party ownership model streamlines the number of counterparties that the public entity has to deal with down to basically one, the PPA provider/developer.
- Path to Ownership: It is possible for a local government to include a buy-out option in the PPA. From a financial perspective, this buy-out option would likely be structured to take place after year 6 so that the original investors are able to capture all of the tax incentives. This buy-out will likely represent a mutually agreed upon fair market value for the PV system. For example, the Denver International Airport (DIA) has entered into a 25-year PPA with MMA Renewable Ventures for a 2 MW PV system at the airport. This PPA contains a buy-out option after year 5 that would allow DIA to take ownership.³⁸ If a buy-out option is not exercised prior to the end of the original PPA term, at the end of the term, the three likely scenarios would be that the host could 1) extend the PPA agreement, 2) purchase the system, or 3) ask that the system be removed.³⁹

Figure 2. Third-Party PPA Model



Disadvantages and Caveats with the Third-Party Ownership Model

While the third-party ownership model can be attractive for state and local governments, it is not perfect. There are nuances to PPA agreements which must be understood before moving ahead with the third-party ownership structure.

- *Green versus Brown Energy:* In third-party PPA agreements, the ownership of the environmental attributes (in the form of SRECs) resides with the owner of the system (i.e. not the state/local government). As a result, state and local governments must be careful in how they market the solar PV systems they host under this model. While somewhat confusing, in the absence of owning the SRECs, it is inaccurate for the City to claim that it is powered by solar energy (or renewable energy for that matter). The owner of the SRECs, which in this case is either the third party PPA provider or the party that has purchased them from the PPA provider, is the only entity that can claim the environmental attributes of the solar power. The rationale behind this distinction is the desire to avoid double-counting of renewable energy credits by more than one entity.⁴⁰ Otherwise, multiple entities could claim they are generating solar power and create the impression that more renewable electricity is being generated than is actually the case.

The accurate description is that the City is *hosting* solar panels on its property which may in itself be sufficient. However, if the City wants to make additional renewable power claims, it could purchase RECs (replacement RECs) in the voluntary green power market. If the City chooses this route, it will be cheaper to purchase RECs that are being generated by wind or biomass projects than to purchase replacement RECs from other solar projects. So for example, if a 250 kW, rooftop PV system in Tucson generates 415,000 kWh or 415 MWh per year,⁴¹ the City can buy wind RECs in the same quantity and then claim that the particular building is powered by renewable energy (but not solar powered since solar RECs were not purchased). Assuming the cost of buying one MWh of wind energy in the form of a REC is \$5.00 (or one-half of one cent per kWh) in the voluntary green power market, the City can "green" up its system for \$2,075.00 per year.

- *Ownership and Facility Access:* In some cases, ownership is important.
 - One of the attractive concepts of PV is the idea of a permanent reduction in electricity costs. Owning a system outright can reduce electricity bills; whereas under a PPA, although a portion of the electricity expense is reallocated away from the utility, 100% of the electricity consumed must be paid for. While a third party PPA can allow for system buy-out options (generally after tax incentives are exhausted), in most cases, truly lower electric bills must wait until the PPA expires and the host exercises the ownership option.
 - Some government agencies, in particular, plant and facility managers may not be comfortable with a third-party having access to and installing equipment on their property. On-going site access is critical to the performance of the system and if that is not acceptable, the third-party ownership model will unlikely be a viable option.

- *Transaction Costs:* There are a number of contracts involved in the third party PPA process. While the host is not necessarily a party to all of these contracts, it is safe to say that it is a legally intensive process which may be costly both in terms of lawyer labor-hours and money, especially if outside counsel is used.

- *Municipal-Specific Contractual Issues:* Most state and local governments approve the funding of their operating obligations on an annual basis, so there is a question about the enforceability of a long-term PPA. This is typically addressed through two mechanisms:
 - Non-appropriation clause: A non-appropriation clause permits the hosting customer to terminate the PPA at the end of any appropriation period without further obligation or payment of any penalty, if and only if, the host was unable to obtain appropriation for funds to meet future scheduled payments and a formal resolution or ordinance is passed. Often, this type of clause will contain a "best efforts" requirement, i.e. the customer promises to use its best efforts to seek and obtain the necessary appropriation for payment. This provision is common in tax-exempt leases and is designed to enable the customer to account for the PPA obligation as a current expense instead of debt.

 - Non-substitution clause: In today's fast evolving solar industry, non-substitution clauses are used to protect a project's viability. If a PPA is cancelled due to non-appropriation, the clause prohibits the customer from replacing the hosted equipment supported by the PPA with equipment that performs the same or similar function. A non-substitution period of 365 days is common, and shorter time periods are also used. Decisions regarding the length of the non-substitution period are based in part on the perceived essential nature of the equipment. Generally, the more essential the equipment is, the shorter the non-substitution period will be. Given the host's right to cancel under the non-appropriation clause, the non-substitution clause is intended to provide some comfort to the investor and the project developer.

- *Legality Concerns:* In Nevada, there may be some question about the legality of using the third-party model for on-site projects. The argument is that by selling power to a host facility, the third-party PPA provider might be illegally competing with the utilities. The Public Utilities Commission of Nevada is investigating these concerns and is expected to make a ruling later in 2008.⁴² The Arizona ACC is likely to rule on this issue in 2008 as well.

- *At or Below Market Rates:* When third-party ownership transactions are announced, the concept of below-market rate electricity is often highlighted as one of the advantages. Representatives of the Connecticut Clean Energy Fund (CCEF) raised an interesting issue related to the equitable nature of below-market rates within the third-party ownership model when combined with a state incentive:

Should limited public funds be used to drive down electricity rates in a PPA below current market rates or are market rates sufficient given PV's promise of predictable future rates?⁴³

The case for requiring market rates for electricity in PPAs can be made when limited public funds are provided through up-front incentives. If market rates are used (rather than below-market rates), program administrators would be able to support more solar PV projects for the same amount of money, or help support the same amount of PV by spending less money. However, this logic assumes that electricity rates will increase in the future. If the market behaves otherwise and future electricity prices fall, below-market PPA rates may cushion the impact to the host since it will be locked into above market electricity rates. In addition, below-market rates can be a powerful incentive to encourage public agencies to sign a PPA and host a solar system. Some agencies may decide that navigating the legal complexities of the PPA process to simply get the same rates they are currently paying is not worth the effort, despite the expected future benefits. Therefore, reducing the agency's electricity bill may indeed be a significant motivator.

In the end, city and state program administrators will determine how best to tailor third-party ownership and the PPAs to meet their PV program goals and to capitalize on any incentives. Certainly, the promise of stable and predictable electricity prices for 20-25 years has value. However, it is only at the end of the life of the PPA, when contracted prices can be retroactively measured against real market prices, will the actual electricity savings be determined.

Who is Using Third-Party Ownership in the Public Sector?

While there are many examples of individual public sector projects which include a third-party ownership structure, comprehensive programmatic approaches to third-party financing are relatively new. States like Massachusetts⁴⁴ and Hawaii,⁴⁵ and local governments such as Boulder County, Colorado⁴⁶ are among those pursuing more comprehensive third-party ownership models. Some examples of PPAs in California and Colorado are included below.

Examples of Third Party PPA Models

- **San Diego's Alvarado Water Treatment Plant⁴⁷**

San Diego's Water Department has entered into a PPA with SunEdison for 1 MW of solar PV at its Alvarado Water Treatment Plant. According to the City's press release, \$6.5 million in upfront installation costs were avoided by signing the PPA with SunEdison (as opposed to buying the system). Once installed, the PV system will cover 20% of the plant's power needs.

- **Port of Oakland⁴⁸**

On November 8, 2007, the Port of Oakland inaugurated its 4,000 panel, 756 kW, ground-mounted PV system. SunEdison financed, built, and will own and operate the system. The Port of Oakland signed a PPA with SunEdison to purchase "clean and predictably priced electricity" for 20 years at a cost of approximately \$4.1 million.⁴⁹

- **Fresno State University**⁵⁰

On November 9, 2007, Fresno State and Chevron Energy Solutions completed the installation of a 1.1 MW PV system that will provide the University with 20% of its annual electricity needs. The project cost approximately \$12 million; an amount that was partially offset by a \$2.8 million rebate from PG&E under California's Self-Generation Incentive Program. Chevron Energy Solutions installed the PV system and Fresno State signed a 20-year PPA with MMA Renewable Ventures. MMA financed and will own the system. The University expects to save \$13 million in avoided electricity costs over a 30-year period.

- **Denver International Airport (DIA)**⁵¹

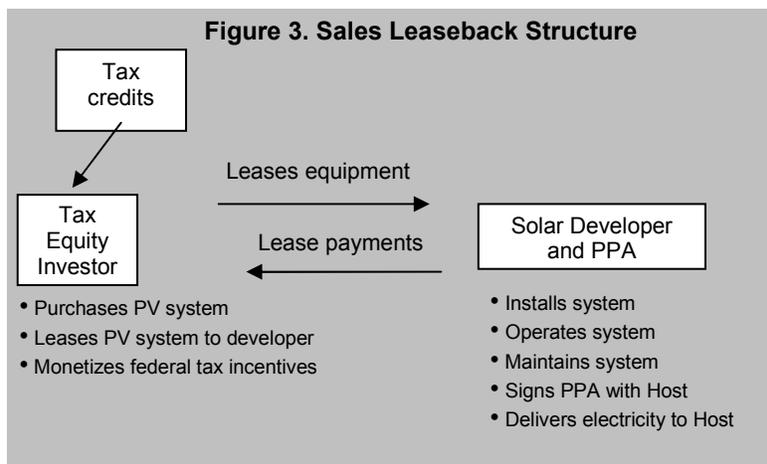
In 2007, DIA announced that it had signed a 25-year PPA with MMA Renewable Ventures for a 2 MW solar PV system which will produce 3.5 million kWh per year. The total cost of power to be purchased under the PPA was reported to be \$10.9 million or roughly 12.5c/kWh. Xcel Energy will provide a \$200,000 rebate to partially offset the project's initial costs. While not stated in the press release, it is also reasonable to assume that MMA sold solar RECs to Xcel Energy as part of the project's financing. The system is expected to begin producing electricity in 2008. Built into the agreement is a buyout option after 5 years allowing DIA to assume ownership of the system.

"Behind the PPA": Sale Leaseback and the Partnership Flip Models⁵²

It is important to understand the dynamics between the solar developer and its tax equity investors as the agreement between these two parties will influence elements of the PPA, including the timing and the cost of any potential buy-out options. Common system ownership structures include the sale-leaseback model and the partnership flip model.

Sale-Leaseback Structure

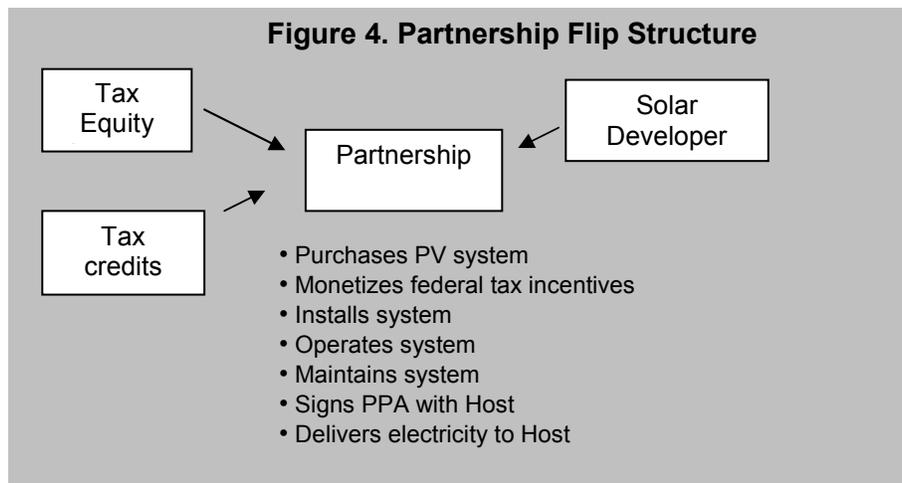
The sale-leaseback structure is shown in Figure 3. Under the sale-leaseback arrangement, the tax equity investor purchases the PV system and leases it to the third-party PPA provider. The third-party PPA provider in turn, signs a PPA with the government agency that will host the PV system. At the end of the lease period, which will likely be after year 6 when the tax benefits have been exhausted, the third-party PPA provider can purchase the system. At that time, and at pre-determined times throughout the remainder of the PPA, the municipality may have the option to purchase the system and take full ownership, if this was contractually arranged in the PPA. The sale-leaseback structure is subject to the same rules of any capital equipment lease, in that the tax investor must show a before-tax, net of investment tax benefit, profit on the lease. Therefore the transaction must be structured so that it shows an economic benefit to the tax investor, other than merely the tax incentives



Partnership Flip Structure

The partnership flip structure is borrowed from the wind industry and is shown in Figure 4. The solar developer and its tax equity investor(s) form a partnership for the express purpose of installing and operating that system, usually in the form of a limited liability corporation (LLC) or other special purpose entity (SPE). This SPE may use debt financing as well depending on the size of the project.

The SPE purchases the PV system and enters into a PPA with the public sector host of the system. The SPE, or its affiliates, will install, operate, and maintain the PV system. The tax equity investor will own a nearly 100% stake in the SPE in the early years of the project (through year 6) in order to monetize the federal tax incentives. When these tax benefits are exhausted, majority ownership “flips” from the tax investor to the developer. At that time, and at pre-determined times throughout the remainder of the PPA, the municipality may have the option to purchase the system and take full ownership, if this was contractually arranged in the PPA.



While the ownership requirements are not clear for solar facilities using the ITC, at the end of 2007, the IRS clarified the rules of the PTC for wind energy deals under Revenue Procedure 2007-65.⁵³ In this ruling, the IRS created a “safe harbor,” whereby if the ownership structure meets the entire set of key requirements, investors can be certain about the allocation of wind tax credits.⁵⁴ While the IRS made it clear that this procedure does not apply to other technologies or other tax credits, the solar industry is using it as a guideline for how the ITC ownership should be structured.

3.2 Clean Renewable Energy Bonds (CREBs)

Tucson is certainly familiar with CREBs having received allocations from the IRS. However, a brief overview is presented below prior to discussing the advantages and disadvantages of the instrument.

Basic Principles of CREBs

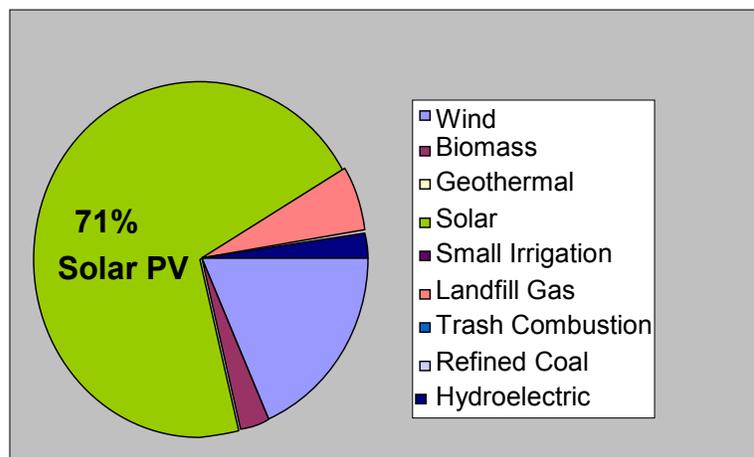
Originally created in the 2005 Energy Tax Incentives Act, CREBs provide a federal tax credit to the bond owners in lieu of interest payments from the issuer.⁵⁵ CREBs allocations are made by the Internal Revenue Service (IRS) based on applications submitted by potential issuers. In theory, interest-free debt is issued in order to finance renewable energy projects. It is this interest-free feature that makes CREBs attractive vis-à-vis tax-exempt municipal bonds or other interest bearing instruments that may be available to finance PV projects.

However, a CREBs issuance is unique for a couple of reasons. The longer the term of the bond, the longer the investor gets to benefit from the tax credit, which increases the cost to the US Treasury. As a result, the IRS limits the term of the bond; this limit is currently 15 years.⁵⁶ The IRS uses the market rate for AA-rated corporate bonds to determine the tax credit offered to investors. Each annual principal payment is treated as a separate bond with its own tax credit rate, rather than a single bond with one tax credit rate over the term of the bond.

Initial Two Rounds of CREBs Allocations

The initial allocation for the CREBs program was \$800 million. Legislation in 2006 increased this amount to \$1.2 billion dollars. In the first round, \$800 million of CREBs allocations went to 610 projects.⁵⁷ Figure 5 shows that 433, or 71%, of these projects were for PV; of these, 93% were in the public sector.⁵⁸

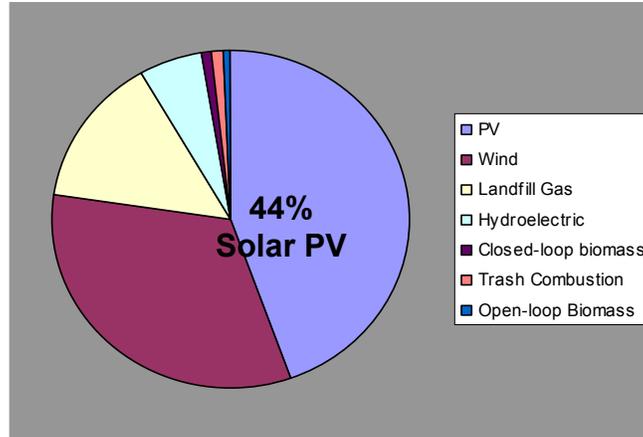
**Figure 5. Allocation of 610 Round 1 CREBs Projects:
Distributed by the Number of Projects per Technology**



Source: Internal Revenue Service 2006

The second round of CREBs applications was due in July 2007⁵⁹ and project awards were announced on February 8, 2008.⁶⁰ 312 projects received allocations totaling \$477 million dollars. Similar to the 2006 allocations, public sector PV projects were awarded a significant percentage of the total allocations. In 2008, as illustrated in Figure 6, 44% of the total number of allocations were for PV projects (includes both governments and cooperatives).⁶¹

**Figure 6. Allocation of 312 Round 2 CREBs Projects:
Distributed by the Number of Projects per Technology**



Source: Internal Revenue Service 2008

Challenges with CREBs

As Tucson is well aware given its knowledge of the CREBs program and its pending CREBs issuance, there are a few important things to keep in mind. First, the bonds must be issued before the end of 2008, or else the City forfeits the ability to secure the CREBs tax credits.⁶² Second, the first payment for a CREB issued in 2008 will be due in December 2008, so Tucson must be prepared to tap other sources of funding to make the first bond payment. Finally, as has recently been the case, there is very limited flexibility with regards to modifying projects once the allocation award has been made. While communication with the IRS has indicated it may be possible to slightly shift project locations, Tucson's efforts to relocate projects to more favorable sites after initial approval have been rejected by the IRS.

Transaction Costs

For small projects, transactions costs can be particularly problematic. The IRS has specific rules regarding how the proceeds from the CREBs can be spent. At least 95% of the CREBs allocation must be invested in qualified project costs.⁶³ Up to 5% of the proceeds can be used to cover non-qualified project costs, including transaction costs, and a debt service reserve fund, if required by investors.

Bundling projects and issuing larger bonds may help reduce these transaction costs on a per project basis. The state of Massachusetts bundled several CREBs issuances together and as a result, was able to achieve notable transaction cost savings. As noted on the March 6, 2008 NREL conference call to discuss CREBs, Massachusetts combined bulk purchasing with CREBs financing to reduce project costs even further.

Interest Rates

To date, according to Bruce Serchuk, a lawyer with Nixon Peabody LLP, most CREBs have been issued at either a discount to par or with a supplemental interest payment. As mentioned, the tax credit earned by a buyer of a CREBs bond is based on the current market rate for AA corporate bonds.⁶⁴ However, issuers are not assured of issuing at this rate for a number of reasons, including:

- 1) The state/municipality's borrowing rate may exceed the current AA corporate rate.
- 2) Investor demand for CREBs may be limited given a lack of familiarity with the instrument, complicating the ability to sell the bonds at par.
- 3) The amount of the bond issue is small.

Figure 7. Clean Renewable Energy Bonds (CREBs)



- Applies to IRS for CREBs allocation
- If received, issues a bond to secure capital for a renewable project.
- **Outlay:** Principal repaid to investor annually in December, starting in the year in which the CREB is issued. Ideally, no interest payment.

- Investor buys CREBs, thus lending money to the project.
- Investor receives a tax credit from federal government in lieu of interest payments.
- May discount the CREBs, or request supplemental interest payment depending on the level of the tax credit and familiarity with the debt instrument.

- Provides investor with a tax credit

Challenges:

- Not truly equivalent to an interest-free bond issue.
- Assumes bond issuer can issue bonds equivalent to AA corporate credit; public entities however may have to make supplemental interest payments, or sell the bond at a discount.
- Limits transaction costs that can be financed by proceeds from the CREBs to 5%.
- First principal payment is due in December of the year the CREBs is issued.

The Future of CREBs

There have been a number of proposals in the House and Senate to expand the CREBs program, often grouped with the reauthorization of production and investment tax credits for renewable energy. Unfortunately, all attempts to allocate additional funding to the CREBs program have failed. The most recent attempt was the Renewable Energy and Job Creation Act of 2008 (H.R. 6049) passed by the House of Representatives in May 2008 which would have established an additional \$2 billion dollars for new CREB allocations. However, the bill failed to make it to the Senate floor. However, if the CREBs program is expanded, then an additional round of CREBs would likely be issued by the IRS soon thereafter, and applicants would have a few months to put together an application.

The proposed legislation may address a few other issues as well. For municipalities, the proposal shifts away from making awards to the smallest projects first, to one that provides a

pro-rata share of the total funds available across all eligible projects that apply. It also proposes to eliminate the requirement to make the first principal repayment in the year that the bond is issued and to either allow for a grace period of some duration or a lump sum payment at maturity.

3.3 Tax-Exempt Renewable Energy Bonds

As an alternative to traditional municipal bond issuances, local governments can also consider issuing tax-exempt energy bonds; the proceeds of which will be used to finance renewable energy installations. However, obtaining the authorization to issue these bonds to finance renewable energy projects may be easier than actually getting the bonds to market.

Four examples of public bond programs that have been approved specifically for renewable energy (including PV) can be found in San Francisco in 2001,⁶⁵ Honolulu⁶⁶ and New Mexico⁶⁷ in 2004, and Delaware in 2007.⁶⁸ To date, of these four, only Honolulu has successfully issued its renewable energy bond. However, to be fair, Delaware's proposal is a recent one and there appears to be some movement in San Francisco as of late related to the use of Proposition H bonds.

In the case of Honolulu and New Mexico, general obligation (GO) bonds were authorized. With GO bonds, the taxing authority of the issuing entity supports the repayment of the debt. Conceptually however, the energy savings from the renewable energy and energy efficiency investments are expected to pay for the bonds over time. Nonetheless, the taxing authority can be drawn upon if needed.

In the case of San Francisco and Delaware, revenue bonds were approved. The repayment of revenue bonds requires that the new projects themselves generate (or save) sufficient revenue to cover both principal and interest. Since revenue bonds don't add to a City's bonding authority and aren't repaid with tax revenue, it may be politically easier to obtain authorization. However, renewable energy revenue bonds may be more complicated to issue because energy savings as a source of repayment is somewhat unique when compared to more traditional revenue bonds that may have a more defined revenue stream identified for debt repayment (e.g. a toll road).

Here are some more specific details of each of these four bond authorizations:

- **Honolulu.** The city issued \$7.85 million in solar general obligation bonds in FY05 and used the proceeds for solar powered parking lots, energy retrofits, and LED streetlamps.⁶⁹
- **New Mexico.** The New Mexico Finance Authority (NMFA) has approval to issue up to \$20 million in general obligation bonds. The proceeds would go towards the Public Project Revolving Fund to make loans to state agencies, universities, and public schools to fund energy efficiency and renewable energy investments. It is expected that 90% of the energy savings will be "captured" from the participating agencies to fund debt service.⁷⁰ No bonds have yet been issued under this authorization.
- **San Francisco.** Proposition B was approved by San Francisco voters in 2001; it gave the city the authority to issue up to \$100 million of revenue bonds for renewable energy projects, including PV. In the same election, Proposition H was passed which gave the City authority to issue additional revenue bonds with greater flexibility as to the issuer and the amount. To date, neither B nor H bonds have been issued, apparently for a number of reasons, including net metering issues between PG&E and the City of San Francisco⁷¹ and some potential creditworthiness concerns at Hetch Hetchy Water and Power.⁷² However, in 2007, the San Francisco Board of Supervisors adopted certain community electricity aggregation measures with Proposition H bonds being cited as the potential funding source for this initiative.⁷³
- **Delaware.** In 2007, Delaware announced the creation of a Sustainable Energy Utility to promote energy efficiency, weatherization, and distributed renewable energy generation, including PV. Proposed funding for the Sustainable Energy Utility would come from a number of sources, including the issuance of special purpose, tax-exempt bonds up to the amount of \$30 million.⁷⁴ Energy savings are expected to generate funds to repay these bonds.

4.0 Review of Incentives and Financing Mechanisms

As noted at the beginning of this memo, many in the Tucson city government are well versed in the financial topics presented in this document. However, for those that may not be as active in the day-to-day process of financing PV installations throughout the City, a summary of the advantages and the disadvantages is presented as follows.

REST:

With the recent approval of production-based incentives for non-residential systems greater than 20 kW, the third party PPA model becomes a more attractive model to the City of Tucson as it considers its financing options for public sector projects. If the City chooses to finance and own PV systems greater than 20 kW, the upfront capital costs will increase by what would have been the amount of the upfront incentives under the old program structure. All else being equal, the City will either have to raise additional funds to install the same size project or reduce the size of the project to match available funding.

For example, if under the original SunShare program, the City would have received an upfront incentive of \$2.50/watt on a 200 kW system; this would have translated into a \$500,000 reduction in the upfront cost of the system from \$1.6 million to \$1.1 million (assuming a cost of \$8/watt). As a result of the new PBI system, the City can either choose to raise an additional \$500,000 in financing to cover the cost of the same 200 kW system, or reduce the size the system by roughly 62 kW so that the upfront installed cost remains the same (\$1.1 million now only buys a 138 kW system). If the City chooses to issue additional debt, the production-based incentives earned by the system will create a source of cash flow that can be used to pay the cost of the incremental debt. According to PVWatts, a 200 kW system in Tucson will generate 332,544 kWh per year. If Tucson qualified for the 15-year, \$.187 per kWh PBI, this would result in an annual payment from TEP of \$62,186 which could be used for debt repayment (see Annex 1 for the PVWatts output table).

Given that one of the primary features of the third party PPA model is that the City avoids the upfront capital costs associated with the installation of a PV system, the fact that this upfront cost will now be much higher than it would have been, now makes the third party model even more attractive. However, small projects that are larger than 20 kW, but not large enough on their own to create interest from PPA providers on a stand-alone basis, may need to be bundled together to create an attractive package of projects for a third party to finance. Alternatively, the City can target these projects for CREBs financing. Projects less than 20 kW continue to qualify for the upfront incentive (UFI) of \$2.50/watt. Therefore, if the City is contemplating smaller projects, for example, on individual schools or libraries, the UFI, combined with the proceeds from CREBs, for example, would be a good way to finance these projects.

Tax Incentives: It is difficult to talk about tax incentives in terms of advantages or disadvantages, but rather can the City benefit from them or not. As previously mentioned, traditionally the City has not been in a position to monetize tax credits or benefit from accelerated depreciation. However, with the advent of the third-party model, Tucson now has the opportunity to leverage these tax incentives. This benefit will be in the form of predictable and competitive electricity rates as agreed to in the PPA. In the future, if the City chooses to exercise a buy-out option, it may be in a position to take ownership of the system at an advantageous price vis-à-vis what the system would have cost initially without the benefits of the tax credits.

CREBs: The advantage of CREBs is the "close to interest-free" issuance of debt. Even though Tucson will likely pay a modest supplemental interest payment to issue its CREBs, it is likely to

be the lowest cost debt available to the City to finance public sector PV systems. The disadvantages of CREBs - or perhaps more appropriately labeled, the caveats involved with the use of the instrument - include internal expectations that the instrument was truly interest-free; the requirement to make annual bond payments with the first payment potentially due prior to the PV system being placed in service; and the transaction costs associated with both applying for the IRS allocation and then issuing the debt. There are cities that decided against applying for an allocation and others who will forego the allocations they received. In the case of Tucson, with the allocations in hand and despite the challenges, it is attractive financing. As noted above, combined with the SunShare incentives (either UFI or PBI), and possibly, bulk purchasing and other cost-reduction strategies, the life-cycle cost of the PV installations financed by CREBs should be attractive. If however the City is faced with issuing CREBs at a steep discount to par, as has been the experience of some other cities, traditional tax-exempt municipal bond issuances might be the more attractive option, all else being equal.

Tax-Exempt Renewable Energy Bonds: While some cities are contemplating the issuance of renewable energy bonds, so far there is not a lot of market experience to draw definitive conclusions. General obligation bonds for renewable energy may be appealing to potential investors given the backing of the City's taxing authority. However, issuing general obligation bonds for PV projects may not be politically feasible. Revenue bonds can be appealing politically, but potentially less interesting to investors. As a result, the jury is still out on dedicated renewable energy bonds. Given the CREBs allocations that Tucson currently has, this alternative form of renewable energy bonds is not necessarily very relevant at this time.

Third Party Models: This memo presents both advantages and disadvantages of the third party model. To summarize, the benefits of the third party model include a minimal initial outlay of capital (if any), the ability to benefit from tax incentives, predictable electricity prices for 20-25 years, no O&M responsibilities, and finally, a pathway to ownership. The disadvantages include relinquishing the right to claim green power unless replacement RECs are purchased, no ownership control, and the need to provide third party access to the City's facilities, which may or may not be a major concern, depending on the facility.

5.0 Summary

Tucson is approaching the installation of public sector PV systems from a number of different angles; a prudent course to take. The availability of capital, system size, and interest in immediate ownership will dictate how each project gets financed. Taking advantage of CREBs, even if a modest supplemental interest payment is required, makes sense vis-à-vis other debt instruments. If City has to heavily discount the CREBs, other tax-exempt financing may make greater financial sense. With the adoption of the PBI under REST, the use of the third party PPA model may accelerate over time given the increase in the required upfront capital outlay. The third party PPA model can take advantage of both the PBI and monetize federal and state tax incentives; a combination that the City can not achieve on its own. Small projects may be better suited for City-financing as they still benefit from upfront incentives (UFI) and are unlikely to be candidates for the third party PPA model unless bundled with larger projects.

Annex 1.



**AC Energy
&
Cost Savings**



Station Identification	
City:	Tucson
State:	AZ
Latitude:	32.12° N
Longitude:	110.93° W
Elevation:	779 m
PV System Specifications	
DC Rating:	200.0 kW
DC to AC Derate Factor:	0.77
AC Rating:	154.0 kW
Array Type:	Fixed Tilt
Array Tilt:	32.1°
Array Azimuth:	180.0°
Energy Specifications	
Cost of Electricity*:	18.7 ¢/kWh

Results			
Month	Solar Radiation (kWh/m ² /day)	AC Energy (kWh)	Energy Value (\$)
1	5.70	25642	4795.05
2	6.11	24240	4532.88
3	7.03	31006	5798.12
4	7.50	31226	5839.26
5	7.28	30256	5657.87
6	7.15	28353	5302.01
7	6.44	26312	4920.34
8	6.85	28225	5278.07
9	7.06	28672	5361.66
10	6.72	28875	5399.62
11	5.99	25746	4814.50
12	5.27	23992	4486.50
Year	6.59	332544	62185.73

*For this model, cost of electricity was set to equal the 15-year PBI in order to calculate the annual revenue from this incentive.

Source: PVWatts.

http://rredc.nrel.gov/solar/codes_algs/PVWATTS/version1/US/Arizona/

- ¹ The BETC Pass-Through Option is described in detail on the Oregon Energy Trust website which can be found at <http://www.oregon.gov/ENERGY/CONS/BUS/tax/pass-through.shtml>.
- ² Cory, Karlynn, Jason Coughlin, et al, "Innovations in Wind and Solar PV Financing," National Renewable Energy Laboratory Technical Report NREL/TP-670-42919, February 2008, at <http://www.nrel.gov/docs/fy08osti/42919.pdf>
- ³ See Section 48 (a) (3) (Investment Credit: Energy Credit) in the IRS tax code.
- ⁴ <http://seia.org/taxmanualdownload.php>
- ⁵ See *A Brief Overview of Depreciation* at <http://www.irs.gov/businesses/small/article/0,,id=137026,00.html>
- ⁶ http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=US06F&State=Federal¤tpageid=1
- ⁷ See IRS Publication 946 at <http://www.irs.gov/publications/p946/ch04.html>
- ⁸ http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=US06F&State=federal¤tpageid=1&ee=1&re=1
- ⁹ <http://www.dsireusa.org/library/includes/statesearch.cfm?EE=1&RE=1>
- ¹⁰ http://www.dsireusa.org/library/includes/incentivesearch.cfm?Incentive_Code=AZ18F&state=AZ¤tpageid=2&search=State&EE=1&RE=1
- ¹¹ http://www.dsireusa.org/library/includes/incentivesearch.cfm?Incentive_Code=AZ08F&state=AZ¤tpageid=2&search=State&EE=1&RE=1
- ¹² http://www.dsireusa.org/library/includes/incentivesearch.cfm?Incentive_Code=AZ20F&state=AZ¤tpageid=2&search=State&EE=1&RE=1
- ¹³ About TEP: Questions and answers about Renewable Energy Standard fees <http://www.tep.com/company/news/REST.asp>
- ¹⁴ <http://www.dsireusa.org/>
- ¹⁵ In addition to renewables, some states use SBC funds to target energy efficiency, energy R&D, weatherization, and low-income customer assistance.
- ¹⁶ http://www.eere.energy.gov/states/alternatives/system_benefits.cfm
- ¹⁷ Refer to http://www.dsireusa.org/documents/summarymaps/PBF_Map.ppt
- ¹⁸ Ibid.
- ¹⁹ About TEP: Questions and answers about Renewable Energy Standard fees <http://www.tep.com/company/news/REST.asp>
- ²⁰ Tucson Electric Power Uniform Credit Purchase Program - Renewable Energy Credit Purchase Program (RECPP). April 19, 2008. http://www.tep.com/Docs/RESTDocs/TEP_RECPEPP_04192008.pdf
- ²¹ http://www.njcleanenergy.com/files/file/NJ-BPU_Market_Transition_Interim_Report_0315076.pdf
- ²² California Solar Initiative Program Handbook. January 2008. http://www.gosolarcalifornia.ca.gov/documents/CSI_HANDBOOK.PDF
- ²³ Ibid
- ²⁴ http://www.njcleanenergy.com/files/file/NJ-BPU_Market_Transition_Interim_Report_0315076.pdf
- ²⁵ California Solar Handbook. p. 38
- ²⁶ Arizona Corporation Commission. Docket NO. RE-00000C-05-0030. 2006 <http://www.azcc.gov/divisions/utilities/electric/res.pdf>
- ²⁷ Customer Self-Directed Renewable Energy Option. REST-TS2. Tucson Electric Power <http://www.tucsonelectric.com/Docs/REST-TS2.pdf>
- ²⁸ Also called renewable energy credits, tradable renewable certificates, or green tags.
- ²⁹ MANUAL PAGE 3
- ³⁰ Guice, J. and J. King. 2008. Solar Power Services: How PPAs are changing the PV Value Chain. Greentech Media Inc.
- ³¹ Denver International Airport
- ³² San Diego's Alvarado Water Treatment Plant
- ³³ Port of Oakland, California
- ³⁴ When a renewable generation owner sells the RECs, it also sells the right to claim they are using renewable power.
- ³⁵ Roy Phillips. President of Marin Solar. November 14, 2007. Presentation. *Solar Technology* Solar Power Project Development and Finance Tutorial. San Diego, CA.
- ³⁶ Ed Horsey. Principal. Enselle LLC. *Modeling Solar Projects*. November 15, 2007. Solar Power Project Development and Finance Tutorial. San Diego, CA.
- ³⁷ http://www.businessweek.com/magazine/content/07_49/b4061074.htm?chan=technology_technology+index+page_top+stories&chan=innovation_architecture_top+stories
- ³⁸ See the Denver Post. October 1, 2007 at http://www.denverpost.com/ci_7056394?source=rss
- ³⁹ Guice, Jon and John D. H. King, "Solar Power Services: How PPAs are Changing the PV Value Chain,"

- Greentech Media, February 14, 2008.
- ⁴⁰ Holt, E. & Associates, R. Wisner, and M. Bolinger. 2006. Who Owns Renewable Energy Certificates? An Exploration of Policy Options and Practice. Lawrence Berkeley National Laboratory. <http://eetd.lbl.gov/ea/emp/reports/59965.pdf> still working on reference
- ⁴¹ PVWatts calculation. http://irredc.nrel.gov/solar/codes_algs/PVWATTS/version1/US/Arizona/
- ⁴² Lacey, Stephen, "Nevada Debates Third-Party Ownership of Renewable Energy Systems," Renewable Energy World, March 24, 2008. at <http://www.renewableenergyworld.com/rea/news/story?id=51908>.
- ⁴³ Personal communications with Lise Dondy and Dale Hedman of the Connecticut Clean Energy Fund, on 12/6/07
- ⁴⁴ Conversations with Jon Abe of the Massachusetts Technology Collaborative
- ⁴⁵ See Hawaii's Governor's Press Release on January 9, 2008. http://hawaii.gov/gov/news/releases/2008/news_item.2008-01-09.3842330405
- ⁴⁶ <http://www.co.boulder.co.us/newsroom/templates/?a=976&z=1>
- ⁴⁷ City of San Diego Press Release. March 1, 2007. <http://www.sandiego.gov/environmental-services/energy/news/pdf/070301.pdf>
- ⁴⁸ Port of Oakland Press Release. November 7, 2007. <http://www.portofoakland.com/newsroom/pressrel/view.asp?id=82>
- ⁴⁹ Port of Oakland Press Release. June 6, 2006. <http://www.portofoakland.com/newsroom/pressrel/view.asp?id=28>
- ⁵⁰ Fresno State News. November 9, 2007. <http://www.fresnostatenews.com/2007/11/solarwrapup2.htm>
- ⁵¹ The Denver Post. October 1, 2007. http://www.denverpost.com/ci_7056394?source=rss
- ⁵² Most of the information in this section was provided through several personal communications with Charles Jennings, of Financial Analytics Consulting Corporation in February and March, 2008. Additional input was provided from Mark Bolinger, Lawrence Berkeley National Laboratory on March 30, 2008.
- ⁵³ "Revenue Procedure 2007-65," Internal Revenue Service, http://www.novoco.com/energy/resource_files/irs_guidance/rulings/proc_07-65.pdf
- ⁵⁴ "IRS Establishes Safe Harbor Provision for Investors Claiming Section 45 Wind Energy Credits," Bracewell & Giuliani Update, October 29, 2007 http://www.bracewellgiuliani.com/index.cfm/fa/news.advisory/item/0d77e273-7527-4f00-90d1-dc105955d58d/IRS_Establishes_Safe_Harbor_Provisions_for_Investors_Claiming_Section_45_Wind_Energy_Credits.cfm
- ⁵⁵ Section 1303 of the Energy Tax Incentives Act of 2005, Pub. L. No. 109-58, 119 Stat. 594 (2005) (the "2005 Act") added section 54 to the Internal Revenue Code.
- ⁵⁶ Clean Renewable Energy Bond Rate: <https://www.treasurydirect.gov/SZ/SPEsRates?type=CREBS>
- ⁵⁷ IRS News Release. November 20, 2006. <http://www.irs.gov/newsroom/article/0,,id=164423,00.html>
- ⁵⁸ Ibid.
- ⁵⁹ http://www.hunton.com/files/tbl_s10News%5CFileUpload44%5C14044%5CCREB_Alert_March2007.pdf
- ⁶⁰ IRS News Release. Feb. 8, 2008. IR-2008-016. <http://www.irs.gov/pub/irs-news/ir-08-016.pdf>
- ⁶¹ Ibid.
- ⁶² This deadline could be pushed back if the CREB s program receives an extension from Congress, but this should not be counted upon.
- ⁶³ "Clean Renewable Energy Bonds – Part III – Administrative, Procedural, and Miscellaneous," Internal Revenue Service, 2007, at <http://www.irs.gov/pub/irs-drop/n-07-26.pdf> Section 2 – top of page 4.
- ⁶⁴ Clean Renewable Energy Bonds. Notice 2007-26. p14. <http://www.irs.gov/pub/irs-tege/n-07-26a.pdf>
- ⁶⁵ Passed Honolulu City Council on June 4, 2004 <http://www.bizjournals.com/pacific/stories/2004/06/21/focus3.html>
- ⁶⁶ <http://www.nmfa.net/loan/?t=State%20Building%20Automation%20Project%20Financing>
- ⁶⁷ Energy Efficiency and Renewable Energy Bonding Act 2005 (HB. 32)
- ⁶⁸ http://www.seu-de.org/docs/fina_report_brief.pdf
- ⁶⁹ Lori Goropse Winguard, Chief of Staff to Council Member Charles K. Djou. Email communication. 10/16/2007.
- ⁷⁰ New Mexico Finance Authority Annual Report 2005. p 24. (<http://www.nmfa.net/uploads/document/Annual%20Report%202005.pdf>)
- ⁷¹ California Assembly AB 2573. April 17, 2006. See page 7. http://www.leginfo.ca.gov/pub/05-06/bill/asm/ab_2551-2600/ab_2573_cfa_20060414_120324_asm_comm.html
- ⁷² http://sfwater.org/detail.cfm/MC_ID/18/MSC_ID/113/MTO_ID/369/C_ID/2422/Keyword/Proposition%20B
- ⁷³ San Francisco's Community Choice Aggregation Program Description and Revenue Bond Plan adopted

by the Board of Supervisors.

http://sfwater.org/detail.cfm/MC_ID/12/MS_C_ID/138/MTO_ID/237/C_ID/2475

⁷⁴ http://www.seu-de.org/docs/fina_report_brief.pdf

